# Transmission pricing methodology review: Beneficiaries-pay options

## Working paper

21 January 2014

Market Design

# 1 Executive summary

### Introduction

1.1 The Electricity Authority (Authority) is conducting a review of the Transmission Pricing Methodology (TPM) in schedule 12.4 of the Electricity Industry Participation Code 2010 (Code). The Authority is developing its response to submissions and cross submissions in relation to the consultation paper *'Transmission Pricing Methodology: issues and proposal'* dated 10 October 2012 (October 2012 issues paper) and to points raised in the May 2013 TPM conference.

1.2 Prior to developing a second issues paper, the Authority is developing and considering key aspects of a revised TPM proposal through a series of working papers. This working paper examines options for applying beneficiaries-pay to recovering the costs of HVDC and interconnection assets, which the Authority proposes to consider for inclusion in the second issues paper. It is the fifth of the series of working papers identified by the Authority.

### Submissions on beneficiaries-pay

1.1 The October 2012 issues paper proposed to introduce a beneficiaries-pay charge calculated using the scheduling, pricing and dispatch (SPD) model used to operate the wholesale market. This charge was referred to as the SPD charge.

1.2 Of the submissions that commented on the SPD charge proposed in the October 2012 issues paper, most did not support the specific proposal. However, a significant proportion of those that commented supported a beneficiaries-pay approach in general. Of the 36 submissions that commented on whether a beneficiaries-pay approach is the optimal approach for recovering HVDC and interconnection costs, 16 submitters[1] provided support or partial support for a beneficiaries-pay approach, while 20 submitters did not.[2]

1.3 Submitters that supported a beneficiaries-pay approach sought a simpler, more certain and less volatile charge that better reflected beneficiaries-pay. To the extent that submitters agreed the SPD charge should apply to historical assets, they considered it should apply to a more limited subset than proposed in the paper. The main points raised in submissions on the design of the beneficiaries-pay charges were as follows: such charges should take into account dis-benefits; calculation of the charge should take into account that demand may be

[1] MEUG, Pacific Aluminium, Contact, Genesis, Meridian, AECT, Business NZ, NZWEA, Northpower, Nova Energy, Unison, Transpower, Orion, Buller Electricity, CHH, NZCID.

[2] TrustPower, MRP, Tuaropaki, Alinta Energy, Auckland, Chamber of Commerce, Auckland Council, DEUN, EPOC, ENA, EMA, NZGA, Phillip Wong Too, PwC, Pulse Utilities, Ringa Matau, Simply Energy, Ventus Energy, WPI, Vector.

responsive to price; that the charge should not discourage embedded generation; and there should be a minimum threshold of 10MW for application of the charge.

1.4 This paper discusses options that respond to these submissions.

**Reasons for considering beneficiaries-pay options**

1.5 Applying some market based approaches, such as capacity rights or long-term contracts may lead to significant market power issues. This means it is likely to be inefficient for them to be adopted as part of the TPM. Large scale economies means market-based approaches based on loss and constraint excess (LCE) yield an insufficient income flow to pay for the grid alone. Accordingly, administrative approaches are required to pay for the costs of the grid that cannot be funded by LCE.

1.6 The ‘loop flow’ characteristics of the interconnected system combined with the large number of parties using it makes it impracticable to adopt an administrative approach of calculating the long-run marginal cost (LRMC) of transmission for each user and setting transmission prices on that basis. The Authority therefore considers that a beneficiaries-pay approach is the next best option in terms of efficiency and practicality.

1.7 The Authority considers that a beneficiaries-pay approach that charges transmission customers on the basis of the gross benefits they receive from transmission investments facilitates dynamic efficiency without greatly compromising static efficiency. This is because charging according to benefit would incentivise consumers to make broadly efficient decisions, as prices will incentivise them to consume no more of a service than their private benefit.

**Beneficiaries-pay options for consideration**

1.8 The Authority has decided to consider the following beneficiaries-pay options:

(a) a simplified version of the SPD charge that seeks to address submitters’ key concerns about design of the charge (**Simplified SPD charge**)

(b) a beneficiaries-pay charging approach based around the grid investment test (GIT). This has two variations, the **GIT-plus-SPD** option and the **SPD-plus-GIT** option

(c) a zonal beneficiaries-pay option that would apply beneficiaries-pay on a zonal basis (**zonal SPD option**).

1.9 All of the above options utilise the SPD method for determining charges for some assets. In the case of the GIT-plus-SPD option, the SPD method is used to calculate investments not subject to the GIT charge. The zonal SPD approach uses the SPD method to determine charges for transmission that enables electricity transfer between zones.

1.10 In identifying beneficiaries-pay options, the Authority decided to limit its consideration to options that use the SPD method to apply a beneficiaries-pay approach to at least some assets. The SPD method enables beneficiaries-pay to be applied in an objective way, with beneficiaries identified using actual wholesale market outcomes.

1.11 The Authority also considered two other simpler options:

(a) a less complex SPD method that, rather than calculating benefits separately for each asset, would calculate benefits from the grid as a whole

(b) an import- and export-based approach that uses the less complex SPD method to calculate benefits to different zones according to whether the grid as a whole provided import or export benefits to the zone.

1.12 The Authority decided to not investigate these options in depth as they spread the costs of a new investment across the entire grid rather than to the parties primarily benefiting from the investment. The Authority does not consider this would promote efficient investment in the electricity industry.

1.13 This paper does not examine whether beneficiaries-pay options should be applied to new investments only, as suggested by some submitters, or historical investments as well. The Authority's approach to charging for historical investments will be informed by the sunk costs working paper and submissions in response to it. This working paper does, however, consider the issue of *if* beneficiaries-pay charges were applied to historical investments *how* should this be done.

**Simplified SPD charge**

1.14 This option is a simplified version of the SPD charge discussed in the October 2012 issues paper that incorporates a number of suggestions from submitters to improve the design of the charge.

1.15 Based on the analysis and modelling presented in this paper, the Authority proposes that the simplified SPD charge would have the following parameters:

(a) it would apply to:

(i) Pole 2

(ii) investments, including replacement assets, added to Transpower's regulatory asset base after 28 May 2004 but before 10 October 2012 with a cost greater than $50m

(iii) investments, including replacement assets, added to Transpower's regulatory asset base from 10 October 2012 with a cost greater than $20m

(b) the charge for a year would be calculated ex post and applied ex ante. For example, charges calculated in relation to the 2013 pricing year would be charged during the 2014 pricing year

(c) the charge would be calculated on the basis of gross benefits from transmission investments for which the charge is being calculated, i.e. disbenefits would be ignored

(d) the amount that could be recovered from beneficiaries for any single day would be capped to no more than the daily share of annualised costs of the investment

(e) where demand is subject to dispatchable demand, dispatchable bids would be used for calculation of the SPD charge, provided dispatchable demand is dispatched. For other demand not subject to dispatchable demand, the SPD charge would be calculated using a demand elasticity based on empirical estimation

(f) the price for non-supply would reflect the frequency of non-supply in the absence of the investment. Of the 10 investments modelled in this paper, this would mean a price for non-supply of $3000/MWh, except for Pole 2, which would have a price for non-supply of $1000/MWh

(g) the charge would be calculated using a three-year rolling average, though this would be subject to review

(h) the charging period would be one year

(i) SPD charges for distributed generation would be calculated either on the basis of net or gross injection to the grid depending on which is most efficient

(j) SPD charges could be calculated at substation level at locations where grid-connected generation has been installed to supply a specific load at a separate node at the same location, provided this is efficient. Otherwise the prudent policy discount could be designed to address this issue

(k) the minimum threshold for the SPD charge would be 10MW by scheme

(l) benefits to IR providers should be included in calculation of the SPD charge.

1.16 The Authority proposes that generators, retailers and direct connect consumers would be subject to the SPD charge.

1.17 Based on qualitative cost-benefit analysis, the Authority considers that the Simplified SPD charge may better promote its statutory objective of promoting competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers than maintaining the status quo. Quantitative cost-benefit analysis would be required to confirm this.

### GIT-plus-SPD option

1.18 This is the first of two variations on a GIT-based option seeking to respond to the suggestions in submissions that, to most effectively promote efficient investment, the charging approach needs to align with the Commerce Commission's transmission investment approvals process.

1.19 Under this approach, a charge would be applied to recover the costs of a transmission investment approved on the basis of a reduction in expected unserved energy, or approved on an N-1 basis.

1.20 The Authority proposes that if the GIT-plus-SPD option were applied, the same criteria would be used for determining the assets subject to GIT-plus-SPD option as for the simplified SPD charge.[3] In particular, the Authority proposes that the GIT-plus-SPD option would apply to:

(a) Pole 2

(b) investments, including replacement assets, added to Transpower's regulatory asset base after 28 May 2004 but before 10 October 2012 with a cost greater than $50m

(c) investments, including replacement assets, added to Transpower's regulatory asset base from 10 October 2012 with a cost greater than $20m.

1.21 Of those investments, a GIT-based charge would be applied to recover the costs of an investment approved primarily on the basis that it:

(a) reduces expected unserved energy, or

(b) is necessary to meet the N – 1 limb of the grid reliability standards.

1.22 The above criteria fit with both the investment test specified for major capex projects approved under the Commerce Commission's Capital Expenditure Input Methodology (Capex IM), and investments approved by the Electricity Commission under schedule F4 of Part F of the Electricity Governance Rules (Rules).

1.23 The GIT-based charge would not apply to minor or base capex proposals.

1.24 The GIT-based charge would be allocated to an "area of benefit". The area of benefit would be the load served by GXPs that benefit from the investment.

1.25 The allocation of the charge would be in proportion to energy consumed in the previous year's measurement period (or, in the case of industrial consumers that have their charges calculated at a substation level[4], net energy consumed).

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[3] See paragraphs 7.4-7.11 for an explanation of the reasons for these proposed thresholds.

[4] See paragraphs 7.90-7.91.

1.26 Project costs that are not recovered through the GIT-based charge would be recovered through a simplified SPD charge, applied to generators, direct connect consumers and retailers on the same basis as under the simplified SPD charge option.

1.27 The following investments would initially be subject to the GIT-based charge (assuming the investment has been completed):

(a) NIGU

(b) NAaN

(c) UNI reactive

(d) Otahuhu GIS

(e) USI reactive

(f) LSI reliability.

1.28 Initially, the following investments would be subject to the simplified SPD charge only, assuming the investment has been completed:

(a) Pole 2

(b) Pole 3

(c) Wairakei Ring

(d) LSI renewables

(e) BPE-HAY.

1.29 Based on qualitative cost-benefit analysis, the Authority considers that the GIT-plus-SPD option may better promote the Authority's statutory objective of competition in, reliable supply by, and efficient operation of the electricity industry for the long-term benefit of consumers than maintaining the status quo. Quantitative cost-benefit analysis would be required to confirm this.

1.30 Because the GIT-based charge enables full recovery of the costs of reliability investments that fall within the application criteria, the GIT-plus-SPD option arguably better achieves beneficiaries-pay than the simplified SPD charge alone. The GIT-based charge could therefore form part of an option for a revised TPM. It should be noted, however, the GIT-based charge is not robust to large changes in generation or demand patterns across the whole grid, as this charge is calculated on expected future benefits not actual benefits.

**SPD-plus-GIT option**

1.31 This is the second approach under a GIT-based option. Under this approach the simplified SPD charge would first be applied to all eligible investments. For investments approved primarily on the basis of a reduction in expected unserved energy, or approved on a N-1 basis (“reliability” investments), the GIT-based charge would then be applied to recover any costs not recovered by the SPD charge. The SPD-plus-GIT approach would be the same in detail as the GIT-plus-SPD approach except for the prior application of the SPD charge to reliability investments before recovery of remaining costs through the GIT-based charge.

1.32 The Authority has modelled this option so that:

(a) the SPD charge would only apply to parties receiving net benefits from an investment

(b) parties receiving dis-benefits from an investment would be compensated for the dis-benefits.

1.33 The option could also be applied so that the SPD charge applied to any party receiving gross benefits from an investment (ie any dis-benefits would not be considered in calculation of the charge).

1.34 This option would enable recovery of costs from reliability investments where capping prevents full cost recovery under the SPD charge. Further, through enabling full cost recovery of reliability investments as a result of the combination of the SPD and GIT-based charges, this option would reflect that the reliability benefits of the investment in the more distant future are likely to be larger, and so parties benefiting from this would have willingly paid for these costs if this were required to secure the investment.

1.35 Based on qualitative cost-benefit analysis, the Authority considers that the SPD-plus-GIT option may better promote the Authority's statutory objective of competition in, reliable supply by, and efficient operation of the electricity industry for the long-term benefit of consumers than maintaining the status quo. Quantitative cost-benefit analysis would be required to confirm this.

1.36 The key advantages of the SPD-plus-GIT charge over the GIT-plus-SPD charge are that it takes into account that the benefits of so-called reliability investments may not be confined to reliability alone and is able to reflect that the pattern of benefit and beneficiaries may change over time. Like the GIT-plus-SPD option it enables full recovery of the costs of reliability investments that fall within the application criteria, so arguably better achieves beneficiaries pay than the simplified SPD charge alone.

**Zonal SPD option**

1.37 This option seeks to respond to suggestions in submissions that charging options should be simple. The option applies beneficiaries-pay in a more aggregated way than other options. As a result, charges may not reflect each party’s private benefit. This option is therefore likely to provide less efficient price signals than options that set prices that more accurately reflect private benefit.

1.38 This option would apply to historical assets regardless of the date assets were added to Transpower's regulatory asset base.

1.39 The zonal SPD option divides the country into several zones. Each zone is connected to other zones by an inter-zonal “interconnector” made up of the transmission assets that enable electricity to flow between the zones. The HVDC would be a separate interconnector and would comprise both Pole 2 and Pole 3.

1.40 The SPD method would be used to identify the benefit to each node or zone from each inter-zonal interconnector. The costs of the investments making up each interconnector would be charged according to each node’s or zone’s share of the benefits from the interconnector (SPD inter-zonal charge).

1.41 Transmission assets that are not part of inter-zonal interconnectors would be deemed to be providing transmission services within the zone only, ie enabling transmission of electricity from generation to load within the zone, or from the border of the zone to a node within the zone, or vice versa. These assets would be charged only to parties within the zone on the basis that the only beneficiaries of these assets are load and generation within the zone.

1.42 There are a number of ways the cost of investments providing intra-zonal transmission could be allocated (ie “within-zone charge”). Only a charge per MWh of load or injection in the zone has been modelled in this working paper.

1.43 The key design issues that would need to be determined for this option are:

(a) definition of zones

(b) definition of interconnectors

(c) charging basis for within-zone charges and whether charges should be levied on generation and/or load.

1.44 Inter-zonal charges would apply to generation, direct connect consumers and either retailers or distributors. Retailers are likely to be the more efficient agent for inter-zonal charges for the same reason as for the simplified SPD charge.

1.45 Since both generators and load benefit from within zone transmission the Authority proposes that both would be subject to within-zone charges – generators, direct connect consumers and retailers or distributors. Whether distributors or retailers are the most efficient agent for end consumers is likely to depend on the design of the charge.

1.46 Based on qualitative cost-benefit analysis, the Authority considers that the zonal SPD option may better promote the Authority's statutory objective of promoting competition in, reliably supply by, and efficient operation of the electricity industry for the long term benefit of consumers than the approach under the status quo for recovering HVDC and interconnection costs. Further quantitative cost-benefit analysis would be needed to establish this.

As with the GIT-based option, elements of this option could be incorporated into a final TPM proposal. Quantitative cost-benefit analysis would be required to determine whether such options provided net benefits.

### Overall assessment of the options

1.47 The Authority has conducted a preliminary assessment of these options, summarised in Table 1. The assessment criteria were developed from submissions on the October 2012 issues paper and from the Authority's economic and decision making framework.

**Table 1: Summary of assessment of beneficiaries-pay options**

| | October 2012 SPD proposal | *Simplified SPD* | *GIT-plus-SPD* | *SPD-plus-GIT* | *Zonal SPD* |
|---|---|---|---|---|---|
| Prices reflect benefit of investment | Yes | Yes | Yes | Yes | Partial |
| Extent of application of beneficiaries-pay | Partial | Partial | Partial, though greater than Simplified SPD alone as applies beneficiaries pay to reliability benefits | Partial, though greater than Simplified SPD alone as applies beneficiaries pay to reliability benefits | Partial |
| Recovery of costs of reliability investments | Partial | Partial | Full | Full | Full |

| | October 2012 SPD proposal | *Simplified SPD* | *GIT-plus-SPD* | *SPD-plus-GIT* | *Zonal SPD* |
|---|---|---|---|---|---|
| Simplicity | 5th | 3rd | 2nd. Calculation of GIT-based charge is simple. SPD charge only applied to subset of assets | 4th. Same assets subject to SPD charge as Simplified SPD but also subject to GIT-based charge | 1st. SPD charge only applies to five interconnectors. Simple within-zone charge. |
| Avoid altering use of the grid | Partial | Partial. Since SPD charge is based on market outcomes incentives may exist to alter grid use to avoid the charge | Partial. Less ability to alter use of the grid to avoid GIT-based charge | Partial. Combination of SPD plus GIT-based charge may mean incentive on parties paying SPD charge to shift costs on to payers of GIT-based charge. Less ability to alter use of grid to avoid GIT-based charge | Partial |
| Incentives for evolution of more efficient charging over time | Yes – provides information that enables development of more efficient charging | Yes – provides information that enables development of more efficient charging | Yes – provides information that enables development of more efficient charging | Yes – provides information that enables development of more efficient charging | Partial – interzonal SPD charge provides information that enables development of more efficient charging |

| | October 2012 SPD proposal | *Simplified SPD* | *GIT-plus-SPD* | *SPD-plus-GIT* | *Zonal SPD* |
|---|---|---|---|---|---|
| Costs involved in implementing option | Development of SPD charge only | Development of Simplified SPD charge only | Development of Simplified SPD charge plus application of GIT-based charge | Development of Simplified SPD charge plus application of GIT-based charge | Development of Simplified SPD charge for interconnectors plus identification of zones and interconnectors and development of within zone charge |
| Incremental participation costs | Need to understand application of SPD charge to multiple assets | Need to understand application of SPD charge to multiple assets | Need to understand application of SPD charge to some assets plus need to understand (simple) GIT-based charge | Need to understand:<br>• application of SPD charge to some assets<br>• GIT-based charge<br>• effect of combination of charges | Need to understand application of SPD charge to interconnectors plus need to understand (simple) within-zone charge |
| Other costs | | Low risk of inefficient disconnection | Medium risk of inefficient disconnection | Medium risk of inefficient disconnection | Low to medium risk of inefficient disconnection |

Source: Electricity Authority

1.48 Determining which option delivers greatest net benefits would require quantitative cost benefit analysis. The Authority intends to develop a refined option or options based on feedback on this and the other working papers. Quantitative cost-benefit analysis would be applied to the Authority's preferred option and an alternative or alternatives in the second issues paper.

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# 2 Introduction

### Background

2.1 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 operating, maintaining, upgrading and extending the transmission grid.

2.2 The Authority considers that the current TPM can be improved so as to better meet the Authority's statutory objective of promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

### Working papers

2.3 The Authority has decided to advance the process of reviewing the TPM by developing a second TPM issues paper (second issues paper) following consideration of submissions on the issues paper released in October 2012 (October 2012 issues paper)[5] and information provided at the TPM conference held in Wellington in May 2013.

2.4 Prior to developing a second issues paper, the Authority intends to develop and further consider key aspects of a revised TPM proposal through a series of working papers, which will form key inputs into the second issues paper.

2.5 This paper is the fifth of the series of working papers identified by the Authority. This working paper examines options for applying beneficiaries-pay to recover the costs of HVDC and interconnection assets that the Authority proposes to consider for inclusion in the second issues paper.

### Other working papers

2.6 Other working papers the Authority has identified include:

(a) Cost benefit analysis –This paper outlines a revised approach that the Authority intends to apply to the cost benefit analysis of proposals in the second issues paper. [6] The paper was released for consultation on 3 September 2013. Consultation on the paper closed on 15 October 2013.

(b) Definition of sunk costs – This paper examines the extent to which the costs involved in the provision of electricity transmission services are actually "sunk" and the implications for transmission pricing.[7] This paper was

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[5] Available from http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c2119

[6] Available from http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c6765

[7] Available from http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c6766

released for consultation on 8 October 2013. Consultation on this working paper closed on 19 November 2013.

(c) Avoided cost of transmission (ACOT) payments for distributed generation – This paper investigates the benefits and costs that result from payment of ACOT to distributed generation. This paper also examines whether or not ACOT payments to date reflect actual avoided costs of transmission.[8] This paper was released for consultation on 19 November 2013. Consultation on this working paper closes on 31 January 2013.

(d) Use of loss and constraint excess (LCE) to offset transmission charges – This paper explores submitter suggestions that the proposed use of LCE to offset transmission charges would distort the otherwise efficient wholesale market signals.[9] This paper was released for consultation on 21 January 2014. Consultation on this working paper closes on 4 March 2014.

(e) Approach to residual charge – This paper will consider whether it may be efficient to levy any residual charge on the basis of congestion or capacity rather than load during peak demand periods.

(f) Connection charges – This paper will examine whether the pool charging approach for transmission connection assets is efficient and whether there is potential for connection assets to be inefficiently classified as interconnection assets.

**Decisions on the TPM**

2.7 Section 32(1) of the Electricity Industry Act 2010 (Act) requires that provisions in the Electricity Industry Participation Code 2010 (Code) must be consistent with the Authority's statutory objective. The TPM is part of the Code, so any amendments to the TPM must be consistent with the Authority's statutory objective.

2.8 In order to assist the Authority to make decisions about the TPM consistent with its statutory objective, the Authority developed a decision-making and economic framework.[10] The Authority applied this framework to derive the proposal for the TPM that is set out in the October 2012 issues paper.[11] After considering submissions on the October 2012 issues paper and the responses of parties to the Authority's questions at the May 2013 TPM conference, the Authority has decided to develop and release a second issues paper, which will include a

8 Available from http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c7428

9 Available from http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c7493

10 Available from http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c6767

11 Available from http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c2119

revised TPM proposal and related guidelines (as referred to in clause 12.89 of the Code) to be followed by Transpower in developing a new TPM.

2.9 In developing the second issues paper, the Authority will continue to be guided in its decisions by its TPM decision-making and economic framework.

2.10 The Authority's Consultation Charter[12] sets out guidelines relating to the processes for amending the Code and the Code amendment principles that the Authority must adhere to when considering Code amendments.

2.11 The Authority will make decisions about the development of the TPM according to its Code amendment principles and the Authority's statutory objective.

[12] Available from http://www.ea.govt.nz/about-us/strategic-planning-and-reporting/foundation-documents/

# 3 Purpose of this paper

3.1 The purpose of this paper is to consult with participants and persons that the Authority thinks are representative of the interests of persons likely to be substantially affected by the TPM.

**Submissions**

3.2 The Authority's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Authority, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with 'Working Paper— TPM beneficiaries-pay options' in the subject line.

3.3 If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to the address below.

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

3.4 Submissions should be received by 5pm on Tuesday 25 March 2014. Please note that late submissions are unlikely to be considered.

3.5 The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions' Administrator if you do not receive electronic acknowledgement of your submission within two business days.

3.6 Your submission is likely to be made available to the general public on the Authority's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Authority on a confidential basis. However, all information provided to the Authority is subject to the Official Information Act 1982.

# 4 Summary of Authority response to submissions

## Introduction

4.1 A full summary of submissions on the beneficiaries-pay charge proposed in the October issues paper, the SPD charge, and other beneficiaries-pay options, and a full transcript of the conference discussion are available at the Authority's TPM review project webpage.[13] This working paper provides an overview of key criticisms of the SPD charge, suggestions for improvements to it, and suggested alternatives.

4.2 Forty-five (45) submissions commented on the merits of the SPD method: seven submitters partially supported the proposal;[14] 38 submitters did not support the proposal. Of the 36 submissions that commented on whether a beneficiaries-pay approach is the optimal approach for recovering HVDC and interconnection costs, 16 submitters provided support or partial support for a beneficiaries-pay approach,[15] while 20 submitters did not.[16]

## Authority response to main concerns with SPD charge

4.3 The main concerns with the SPD charge and the Authority's response are summarised in Table 2. A conceptual explanation of the SPD method is provided in Appendix A.

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13 Available from http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/

14 MEUG, NZX, Pacific Aluminium, Meridian, Smart Power, BusinessNZ, and Nova.

15 MEUG, Pacific Aluminium, Contact, Genesis, Meridian, AECT, Business NZ, NZWEA, Northpower, Nova Energy, Unison, Transpower, Orion, Buller Electricity, CHH, NZCID.

16 TrustPower, MRP, Tuaropaki, Alinta Energy, Auckland, Chamber of Commerce, Auckland Council, DEUN, EPOC, ENA, EMA, NZGA, Phillip Wong Too, PwC, Pulse Utilities, Ringa Matau, Simply Energy, Ventus Energy, WPI, Vector.

**Table 2: Submitter comments and Authority response**

| | Submitter comment | Action |
|---|---|---|
| 1 | Calculating the charge using half-hourly calculations of private benefit would result in an uncertain, complex and volatile charge | Charge uncertainty can be addressed by calculating and setting the charge prior to the charging period. The Authority will consider calculating the charge over longer periods to reduce its short-term volatility but notes that half-hourly calculations are the same time period as that used to discover wholesale market prices. The Authority will consider simpler charging designs but it considers the SPD method is an effective means of applying beneficiaries-pay. |
| 2 | Capping the revenue recovered in each half-hour to the half-hourly share of the annual costs of an investment undermines the beneficiaries-pay principle by preventing the full costs of an investment being recovered from the parties that benefit from the investment | Shorter capping periods minimise the incentives to game the charge. A longer capping period increases the incentives to game the charge as it increases the possibility that a substantial portion of an investment's costs would be covered in a small number of periods. |
| 3 | An ex-post charge (that is, a charge that is determined after the charging period) will cause uncertainty and (unacceptable) volatility | The Authority is considering calculating the charge ex-post but setting the charge prior to the charging period (as is done under the status quo) to address uncertainty of the charge. Volatility is a function of the period used to calculate the charge and other key parameters, such as the cost that applies when removal of the asset would result in unserved energy. Volatility would not arise because of ex-post calculation of the charge. |
| 4 | Generators will be able to alter their offer behaviour to avoid the SPD charge, which will cause inefficient dispatch and enable them to pass a greater | While generators may be able to alter their offer behaviour to minimise the charge they face they are unlikely to be able to avoid it entirely. The extent to which they can do this depends on how demand is modelled in the calculation of SPD charge, which the Authority is reconsidering. |

| | | |
|---|---|---|
| | share of the costs to consumers | |
| 5 | The proposal to use the SPD method to allocate costs for investments made since May 2004 and Pole 2 involves reallocating sunk costs which compromises efficiency | The Authority has published a working paper on this issue. The paper suggests that even if transmission costs are sunk altering transmission charges to reflect the full costs of providing transmission services could promote efficiency, especially dynamic efficiency. However, this would depend on the detail of the charge design and its effects. Charges would be designed to promote efficiency and this would be assessed through cost-benefit analysis. |
| 6 | The SPD charge should apply to a much more limited set of historical investments, such as those with a cost greater than $100 million | The Authority is considering applying a simplified SPD charge to:<br><br>• Pole 2<br>• investments, including replacements assets, added to Transpower's regulatory asset base after 28 May 2004 but before 10 October 2012 with a cost greater than $50m<br>• added to Transpower's regulatory asset base from 10 October 2012 with a cost greater than $20m<br><br>However, simpler charging options, such as the zonal SPD option, could apply to all non-connection and non-static-reactive assets (as the current interconnection charge does except for the HVDC). |
| 7 | The SPD charge should reflect disbenefits as well as benefits | This paper considers applying an SPD charge on both a net benefit basis (ie benefits minus disbenefits) and a gross benefits basis (ie ignoring disbenefits). |
| 8 | Key design elements, such as assumptions around the wholesale demand curve for electricity and, in particular, the assumption of no demand response and the cost of alternatives in the event of non- | This paper considers the efficiency of changes to assumptions to key inputs, such as assumptions around the price-responsiveness of demand, and the costs assumed in the event of non-supply. |

| | | |
|---|---|---|
| | supply as a result of removal of the investment, are not consistent with efficiency | |
| 9 | The SPD method should not disincentivise embedded generation where this is efficient or disincentivise generation built to support industrial load. | This paper considers applying the SPD charge to embedded generation on a net rather than gross generation basis, which would mean embedded generation is not subject to the SPD charge unless there is net injection at the relevant node. The paper also considers whether it would be more efficient to apply the SPD charge on a substation basis at nodes with significant industrial load. This would mean generation built to support industrial load would only be subject to the SPD charge if there was net injection at the substation. |
| 10 | There should be a minimum threshold for application of the SPD charge to generation of 10MW | This paper considers a 10MW minimum threshold that would apply to individual generation schemes rather than individual generators. Applying a threshold of 10MW to generators would exclude some large schemes with total generation capacity above 10MW, e.g. large windfarms. |

Source: Electricity Authority

4.4 Section 6 explains in more detail the options that the Authority considers may meet the concerns described in this section.

# 5 Why focus on beneficiaries-pay options?

### Characteristics of efficient transport prices

5.1 The decision-making and economic framework consultation paper[17] noted that transmission services are essentially transport services. In particular, transmission services involve the transportation of a product (electricity) from the place of production (where the electricity is generated) to consumers directly connected to the grid (direct connect consumers) and distributors that transport the product to the end consumers.

5.2 Provided the transport market is workably competitive, transport businesses (including transmission) are forced to set their prices for a service at the level that just covers both:

(a) the additional cost of transporting another unit, e.g. a package or a passenger, which will include the costs of fuel, drivers, etc - the short run marginal cost (SRMC)

(b) the cost of adding another unit of transport to the service, e.g. a truck, – the long run marginal cost (LRMC).

5.3 When there is workable competition this pricing structure promotes three sources of efficiency:

(a) productive efficiency – the efficient production of transport services as otherwise new entrants with lower costs will enter or threaten to enter the market at lower prices and take away business from other producers if their costs remain higher

(b) allocative efficiency – the efficient use of the transport service, as producers and consumers will transport their goods only when the benefits of transporting exceed the costs of transport

(c) dynamic efficiency – efficient investment decisions as:

(i) consumers and producers face price signals that ensure they take into account the cost of transport when deciding where to locate their next plant and/or expand existing plant; and

(ii) transport businesses face price signals that ensure they only add capacity to their business when consumers are willing to pay.

5.4 Dynamically efficient pricing provides signals about both contraction and expansion of services. Where lack of demand means the transport service is not able to recover its SRMC this provides a signal to reduce the service, e.g. reduce the number of flights to a particular destination. Similarly, where excess demand

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[17] Decision-making and economic framework for transmission pricing methodology review: consultation paper, page 21. Available from http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c6767

means the firm could recover more than LRMC it has a signal to expand the service, e.g. increase the number of flights to a destination.

**Efficient pricing for transmission services**

5.5 Transmission is not, in general, subject to workable competition as it is a natural monopoly. Further, transmission is subject to significant economies of scale so charges based on SRMC would significantly under-recover the costs of providing transmission services.

5.6 However, nodal pricing should provide (approximately) correct signals about the SRMC of transmission through its pricing of losses and constraints on the grid. This means that nodal pricing promotes both:

(a) productive efficiency, by providing signals for the efficient operation of the transmission network

(b) allocative efficiency, by providing signals for the efficient use of the transmission network, as generators and consumers will only use the transmission network when the benefits of the transmission of power across the grid exceed the costs.

5.7 As some submitters on the October 2012 issues paper and the cost-benefit analysis working paper have pointed out, charges based on the LRMC of transmission would provide efficient price signals about the cost of transmission investment. The LRMC of transmission can be defined as the capital and operating costs that would be incurred to increase transmission capacity rather than by one unit. Charges based on LRMC would promote dynamic efficiency since such charges would ensure that:

(a) consumers and producers face price signals that ensure they take into account the cost of transmission investment when making their own investment decisions. This includes investment decisions in relation to:

(i) expansion

(ii) location

(iii) innovation

(b) the transmission provider would face a price signal to only add capacity when consumers of transmission services are willing to pay for it.

5.8 Establishing prices based on LRMC to *connect* to the grid is relatively straightforward. A customer may contract with Transpower under a new investment contract, under which Transpower agrees to make a transmission investment in return for a charge. Otherwise, a customer may connect to existing assets under a bilateral transmission agreement.[18] Under a new investment

[18] If Transpower and the customer do not agree on a transmission agreement, the Benchmark Agreement applies as the default transmission agreement.

contract, if the customer requires a change in capacity or, the parties may negotiate arrangements to make further investments. The customer will willingly pay for the transmission assets that deliver benefits to them if failure to establish a contract for those assets would mean they were precluded from receiving those benefits. Under a transmission agreement/the Benchmark Agreement, there is a process for considering upgrades/changes to connection assets in the event that Transpower has identified potential reliability issues.[19]

5.9 Dynamic efficiency is promoted by contract-based arrangements provided consumers are able to secure the benefits they are seeking without impinging on the property rights of other parties who are not party to the contract. Since it is straightforward to construct contracts that protect parties' property rights at the periphery of the grid, market-based approaches such as contracts or capacity rights can therefore be readily used to establish prices based on LRMC for connection or, potentially, spur lines. Capacity rights could also be applied across the HVDC but the Authority considers that the risk of market power problems plus significant practical implementation difficulties means that capacity rights are not a viable option for the HVDC.

5.10 The meshed nature of the interconnected grid and the large number of parties that use it means it is likely to be impracticable to use mechanisms such as capacity rights or contracts to establish prices based on LRMC for the interconnected grid. This is because:

(a) loop flows in the interconnected grid means it is difficult to define property rights over much of it, which precludes the use of mechanisms such as contracts or capacity rights for establishing prices

(b) the number of parties involved means transaction costs are likely to preclude the use of contracts for establishing prices.

5.11 Given this, an administrative approach for establishing prices is likely to be required. Even though it is not possible to use market-based arrangements to establish prices based on LRMC for the interconnected grid, the Authority considers that it is possible to utilise the fact that, under market-based approaches, consumers will only be willing to pay for a service up to the level where it provides the benefit they seek from it.

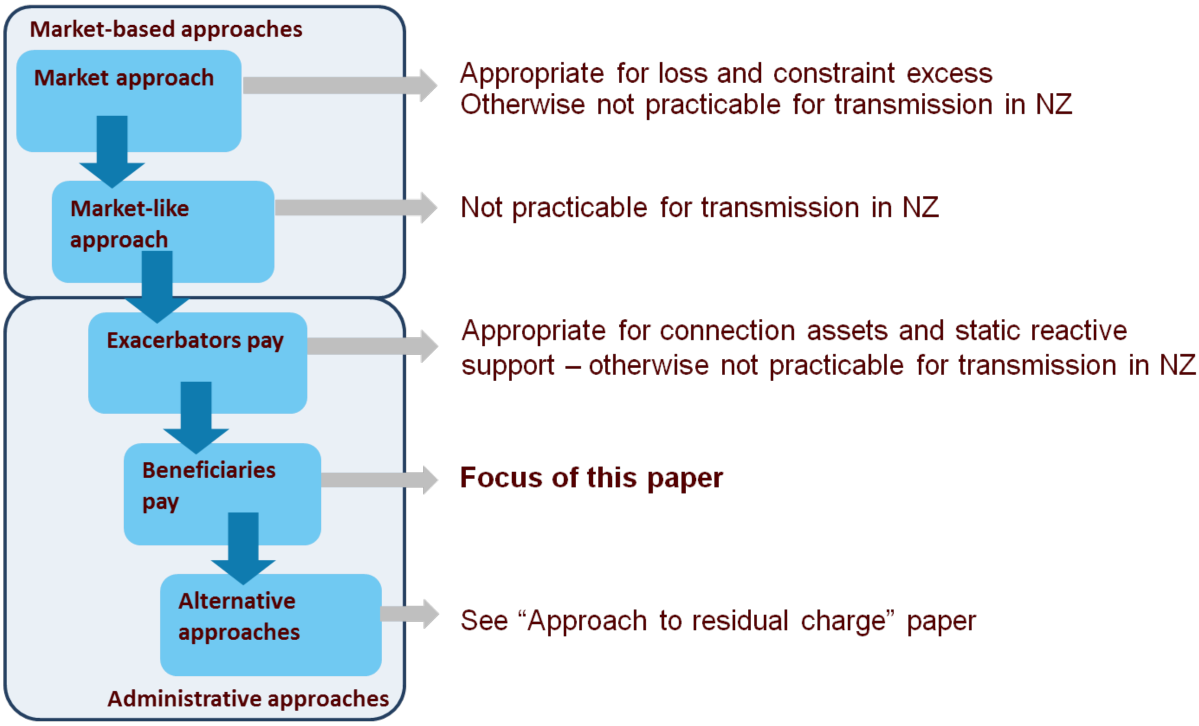
5.12 In particular, charging according to incremental benefit takes advantage of the fact that consumers are only likely to be willing to purchase an increment to a service up to the point where their marginal private benefit equals their marginal private cost. This means consumers have incentives to make broadly efficient decisions under a beneficiaries-pay approach, as the price incentivises them to consume no more of the service than their private benefit.

[19] In some cases, this may involve Transpower getting approval from the Commerce Commission to make the reliability investment.

5.13 The Authority acknowledges that setting prices according to incremental benefit at best only approximates efficient signals since prices are unlikely to reflect LRMC. However, in the absence of a mechanism that produces prices that reflect LRMC, benefit-based charges are likely to be the most efficient means of promoting dynamic efficiency.

5.14 The place of beneficiaries pay in the Authority's decision-making and economic framework and the rationale for applying this approach is summarised in Figure 1.

**Figure 1: Application of decision-making and economic framework for TPM**




Source: Electricity Authority

### Could causer pays pricing be used?

5.15 Some submitters on the October 2012 issues paper considered causers pay would better promote dynamic efficiency as prices based on causers pay were more likely to reflect LRMC than prices based on beneficiaries-pay.[20]

5.16 The Authority notes that in some other regulated sectors administrative pricing methodologies are used to establish prices that seek to approximate LRMC. In particular, in telecommunications regulated prices are often based on total service long run incremental cost (TSLRIC). TSLRIC is the long-run cost of the increment to the network required to provide the total service in question. TSLRIC is usually calculated by modelling the increment to the network required

20 e.g. Vector, DEUN.

to provide the service in question, e.g. the interconnection of a particular customer.

5.17 In terms of the Authority's decision-making and economic framework, even though a TSLRIC-based charge would be set administratively, it can be considered market-like in that it reflects a charge similar to that which would arise in a workably competitive market, since the price approximates LRMC. This means that it would sit above the beneficiaries-pay charge in the Authority's hierarchy of preferred options for a TPM.[21]

5.18 TSLRIC could be applied to transmission by identifying the incremental change to the transmission network needed to provide transmission services to a particular customer.[22] One way this could be done would be to model the grid that would be required in the absence of a customer and compare this to the current grid in order to identify the incremental costs involved in providing transmission services to that customer. This is a possible variation on what was previously referred to as "but-for" pricing. (In this case, the costs a customer would be charged for would be the cost of those assets that would not be required but for the connection of the customer.)

5.19 However, the significant economies of scale involved in transmission investment and the need to deal with loop flows in transmission design mean it is likely to be impracticable to apply this approach to non-connection assets in New Zealand. In addition, a methodology (or method) would have to be identified or developed to model the increments to the transmission network required to service transmission customers. Accordingly, the Authority is not proposing to develop this option further.

[21] See October 2012 issues paper, paragraph 5.2.1.

[22] Note that TSLRIC pricing as applied under telecommunications regulation in New Zealand may under-recover costs if it were applied to recovering Transpower's costs. This is because TSLRIC as applied to telecommunications uses forward-looking costs and not the prices actually incurred by the provider. Accordingly, if forward-looking costs were less than Transpower's actual costs, insufficient revenue would be recovered under TSLRIC pricing based on forward-looking costs. Since the TPM must recover Transpower's full economic costs (clause 12.78 of the Code) a residual charge may therefore be required.

# 6 Beneficiaries-pay options the Authority is proposing to consider

### Introduction

6.1 The Authority has decided to consider the following beneficiaries-pay options for transmission pricing:

(a) A **simplified version of the SPD charge** that seeks to address submitters' key concerns about design of the charge.

(b) A beneficiaries-pay charging option based on the investment test for major capex set out in the Commerce Commission's capital expenditure input methodology and, for investments that pre-date November 2010, the grid investment test previously set out in Schedule F4 of Part F of the Electricity Governance Rules. There are two approaches to this option. **GIT-plus-SPD** would apply a beneficiaries-pay charge to parties benefiting from investments approved primarily on the basis of a reduction in expected unserved energy (EUE) or on the basis that the investment is necessary to meet the N – 1 limb of the grid reliability standards. The simplified SPD method would be used to apply charges for investments approved primarily for other reasons. The **SPD-plus-GIT** approach would apply the simplified SPD charge first to all eligible investments and then the GIT-based charge would then be applied to recover any costs not recovered by the simplified SPD charge.

(c) A **zonal beneficiaries-pay** option that would apply beneficiaries-pay on a zonal basis. This option divides the transmission network into zones and uses the simplified SPD method to identify beneficiaries at a zonal level from transmission assets that enable transfer of power between zones ("zonal interconnectors"). It also allocates the costs of transmission assets that enable transfer of power within a zone to the parties generating or purchasing electricity within that zone.

6.2 This section sets out why these options were selected. The options themselves are described in detail in sections 7 to 10. Those sections also present the results of modelling for these options and provide a qualitative cost-benefit analysis of each option, as well as an assessment of the practicality of each option.

6.3 This paper does not examine the issue of *whether* beneficiaries-pay options should be applied to new investments only, as suggested by some submitters, or historical investments as well. The issue of whether transmission costs are sunk or not and the implications of this for transmission pricing are examined in the sunk costs working paper. The Authority's approach to charging for sunk assets will be informed by the sunk costs working paper and submissions in response to it.

6.4 Instead, this paper considers *if* beneficiaries-pay charges were applied to historical investments *how* should this be done. Accordingly, it presents modelling showing the impact of options applied to some, or in the case of the zonal option, all, historical transmission investments for which costs need to be recovered.

**Identification of beneficiaries-pay options**

6.5 In identifying beneficiaries-pay options, the Authority decided to limit its consideration to options that incorporate use of the SPD method to apply beneficiaries-pay to at least some assets. The reason for this is that the SPD method enables beneficiaries-pay to be applied in an objective way, with beneficiaries identified using actual wholesale market outcomes. Like other beneficiaries-pay options that use models to identify beneficiaries, some of the parameters can involve a degree of subjectivity. However, unlike methods that identify beneficiaries on a forward looking basis using models, once the parameters are established, the SPD method is flexible to significant changes in the pattern of grid use over time.

6.6 The Authority considered that at least one of the options examined should be based on the option proposed in the October 2012 issues paper, but modified to reflect comments in submissions on that proposal. This is the reason for the inclusion of the simplified SPD charge option discussed in section 7.

6.7 The Authority also decided that an option should be examined that reflected the view expressed in some submissions that beneficiaries-pay would only promote efficient transmission investment if beneficiaries-pay was applied in a way that reflected the transmission investment decision process. This is the reason for the inclusion of the GIT-based option discussed in sections 8 and 9.

6.8 A number of submissions considered the Authority's proposal in the October 2012 issues paper was too complex and sought a less complex option. In addition, some submissions considered the proposal only applied beneficiaries-pay in a limited way, which would detract from the promotion of efficiency. For these reasons, the Authority considered three less complex options that sought to apply beneficiaries-pay across the whole grid but as simply as possible:

(a) a less complex SPD method that, rather than calculating benefits separately for each asset, calculated benefits from the grid as a whole

(b) an import- and export-based approach that calculated benefits to different zones according to whether the grid as a whole provided import or export benefits to the zone

(c) zonal SPD approach, as briefly described in paragraph 6.1(c).

6.9 Of these three less complex options, the Authority considers that the zonal SPD option (discussed in section 10) is the only option that warrants further consideration. This is because the prices from the less complex SPD method and the import- and export-based approach spread the costs of a new investment across the entire grid proportional to the benefit each beneficiary is assessed as receiving from the grid as a whole. This means that if parties in, say, Auckland are calculated as benefiting more from the grid as a whole than, say, parties on the West Coast of the South Island, parties in Auckland would be charged proportionately more for an investment on the West Coast of the South island than parties on the West Coast itself. It is unlikely, however, in reality that parties in Auckland would benefit more from the investment. This means it is unlikely these options would promote efficient investment in the electricity industry more effectively than options that calculate benefit and apply charges on a more locational basis.

6.10 The less complex SPD method and the import- and export-based method are described in Appendix B, together with modelling results for these options.

# 7 Option 1 - Simplified SPD charge

7.1 This option is a simplified version of the SPD charge discussed in the October 2012 issues paper that incorporates suggestions from submitters to improve the design of the simplified charge.

**Concept of simplified SPD charge**

7.2 The concept of this option is the same as the SPD charge proposed in the October 2012 issues paper:

(a) beneficiaries of transmission investment would be charged according to the private benefits they derive from the transmission investment

(b) the benefit they derive would be calculated using the wholesale market model (SPD) or its equivalent (vSPD)

(c) the charge for each party would be based on the increase in their producer surplus (for generators) or consumer surplus (for load) in the wholesale market as a result of having the transmission investment in question in place compared with the grid in its pre-investment state[23].

**Revisions to parameters used for calculation of simplified SPD charge**

7.3 The simplified SPD charge option involves a number of changes to the inputs and to the way the simplified SPD charge would be calculated, compared with the SPD charge proposed in the October 2012 issues paper. These changes are described in table 3.

[23] Depending on the investment, the pre-investment state may be with the investment removed or it may be an older asset that was in place prior to the investment, etc.

**Table 3: Overview of parameters for simplified SPD charge compared with 2012 proposal**

| *Issue* | *2012 proposal* | *simplified SPD charge* | *Options considered* | *Rationale* |
|---|---|---|---|---|
| Assets subject to simplified SPD charge | Assets added to Transpower's regulated asset base after 28 May 2004 with a cost greater than $2m, and Pole 2 | (a) Pole 2<br>(b) investments, including replacement assets, added to Transpower's regulatory asset base after 28 May 2004 but before 10 October 2012 with a cost of greater than $50m<br>(c) investments, including replacement assets, added to Transpower's regulatory asset base from 10 October 2012 with a cost of greater than $20m. | 2012 proposal, revised proposal, different cost and timing thresholds | Captures bulk of Transpower's MAR to be recovered under original proposal but SPD charges apply to fewer assets initially. Threshold for new investments consistent with threshold for major capex under Commerce Commission's Capex IM.<br>10 October 2012 was the date the Authority released the October 2012 issues paper, it is reasonable to assume that parties took into account the possibility of the SPD charge applying to new investments from that date. |

| *Issue* | *2012 proposal* | *simplified SPD charge* | *Options considered* | *Rationale* |
|---|---|---|---|---|
| | | | | |
| Calculation period for charge ex post or ex ante? | Ex post – charge for a month based on market outcomes for that month | Ex ante – charge for a period (e.g. a year) based on outcome for previous period (e.g. previous year) | Monthly, annual, two-year rolling average[24] | Modification should improve charge certainty as parties will have certainty of the charge they face for the period in which they are operating |
| Calculation of benefits from an investment based on net or gross benefits? | Gross benefits – calculation based only on benefits from an investment and ignored disbenefits | To be determined through CBA. Proposed to use gross benefits.<br>If net benefits with compensation to disbeneficiaries is used, compensation would be funded from residual charge | Gross benefits, net benefits with compensation to disbeneficiaries, net benefits only (no compensation) | Charging on net benefits basis consistent with investment decisions. Charging on gross benefits still provides incentives for efficient decisions, ensures greater proportion of costs are recovered from beneficiaries. Charging on the basis of net benefits with no compensation likely to result in inefficient vertical integration to |

24 While the Authority modelled a two-year rolling average for this charge, a longer period such as three years may be preferred in practice if it meant parties subject to the charge were less able to alter their behaviour to avoid the charge.

| *Issue* | *2012 proposal* | *simplified SPD charge* | *Options considered* | *Rationale* |
|---|---|---|---|---|
| | | | | avoid the charge |
| Maximum cost-recovery within a period (capping period) | Half hourly – share of annualised costs that may be recovered from beneficiaries within a particular timeframe limited to half-hourly share of annualised costs of the assets | More than half hourly – limited to either daily, weekly, or monthly share of annualised costs of the assets | Daily, weekly, monthly | More consistent with beneficiaries-pay as increasing the capping period means more costs are recovered from beneficiaries rather than through the residual charge. A capping period is required to limit incentives for inefficient behaviour to avoid the charge |
| Cost that applies in event of non-supply in counterfactual SPD case ("Value of lost load (VoLL")) | $3000 | Calculate for each investment the amount of non-supply that would occur with the investment removed (ie what the SPD counterfactual would have been if the cost of non-supply was $3,000/MWh (or $1000/MWh for Pole 2) and then convert this into a capacity factor. The price | | Ensures that benefit calculation better reflects the benefits in the long run from the investment |

| *Issue* | *2012 proposal* | *simplified SPD charge* | *Options considered* | *Rationale* |
|---|---|---|---|---|
| | | for non-supply based on the implicit capacity factor for an asset is then applied at all nodes across the country when the SPD charge for that asset is being calculated | | |
| Slope of demand curve | Vertical up to point of non-supply - assumes perfectly price inelastic demand, ie demand does not respond to wholesale market prices. At point of non-supply, horizontal | Use demand curves that imply some demand response to wholesale market prices | (a) Apply a cost of non-supply of $3000/MWh, plus apply a demand curve based on actual price-responsive bids into the Price Response Schedule (PRS). Bids must result in actual price response.<br>(b) Apply a cost of non-supply of $3000/MWh, plus price-responsive bids of $200/MWh at specified quantities at industrial nodes showing a price response.<br>(c) Apply a cost of non-supply of $3000/MWh, plus 2.5% of actual load at each node bid at $200/MWh and 10% of actual load at each | Closer reflection of reality that some demand does respond to high wholesale prices |

| *Issue* | *2012 proposal* | *simplified SPD charge* | *Options considered* | *Rationale* |
|---|---|---|---|---|
| | | | node bid at $1000/MWh. (This crudely represents a short-term price elasticity of demand of -0.01.)<br><br>(d) apply approach for determining cost of non-supply only, ie vertical demand curve up to cost of non-supply | |
| Calculation of charges for nodes with embedded generation – net or gross injection? | Gross injection | To be determined. Could consider net injection – ie generation minus demand at the node<br><br>SPD charge calculated at substation level at locations where grid-connected generation has been installed to supply a specific load at a separate node at the same location but would only take this approach if demonstrated to be more efficient than SPD charges based on gross injection. | Both net and gross injection | Some argue that SPD charges based on net injection better ensures that charges to embedded generation reflect the benefit they receive from the grid, and that major industrial load has efficient incentives to invest in generation to support its processes and incentives for efficient grid configuration at industrial locations. Gross injection would |

| *Issue* | *2012 proposal* | *simplified SPD charge* | *Options considered* | *Rationale* |
|---|---|---|---|---|
| | | | | be preferred if substantial charge avoidance would occur if SPD charges were calculated on a net injection basis |
| Minimum threshold for generation subject to SPD charge | 1MW | 10MW by scheme | 10MW by generator, 10MW by scheme | A threshold is needed to ensure the benefits of collecting a charge from small generators do not exceed the costs, including compliance and transactions costs. A threshold based on scheme size is proposed as some schemes may be very large but the generators may be below 10MW, e.g. windfarms |

Source: Electricity Authority

### Assets subject to the simplified SPD charge

7.4 Reflecting comments in submissions, the Authority proposes that the simplified SPD charge would be applied to a more limited number of assets than that proposed in the October 2012 issues paper. In particular, the Authority proposes that the simplified SPD charge would apply to:

(a) Pole 2

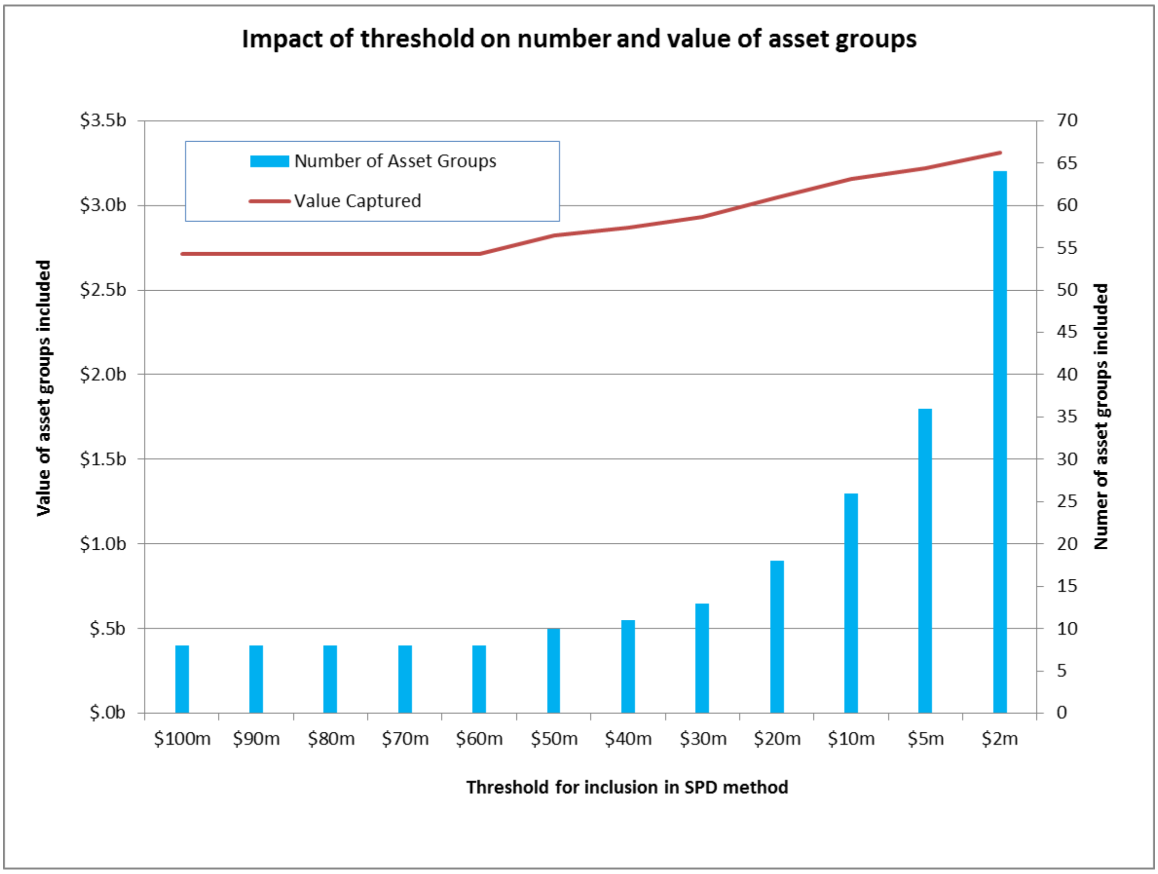
(b) investments, including replacement assets, added to Transpower's regulatory asset base after 28 May 2004 but before 10 October 2012 with a cost of greater than $50m

(c) investments, including replacement assets, added to Transpower's regulatory asset base from 10 October 2012 with a cost of greater than $20m.

7.5 The rationale for 7.4(b) is that it would limit historical application of the SPD charge to large recent investments and Pole 2. These make up the bulk of Transpower's maximum allowable revenue to be recovered in relation to interconnection and HVDC assets added to the regulatory asset base since 28 May 2004 (except Pole 2) and above a value of $2m as shown in Figure 2. These assets represent approximately 81% of Transpower's total regulatory asset base.

7.6 Pole 2 is the fourth largest investment by cost among the assets that the Authority originally proposed would be subject to the SPD method in the October 2012 issues paper. As one of the highest cost investments, the Authority considers that it is appropriate that it is charged on the same basis as other high cost investments, in particular, Pole 3.

**Figure 2: Impact of SPD threshold on number and value of asset groups**




Source: Transpower

Notes: 1. Available at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/spd-pricing-asset-groups.xlsx

7.7 As noted in the previous section, this threshold does not take into account the possibility that the threshold may change as result of consultation on the sunk costs working paper.

7.8 The rationale for the $20m threshold in 7.4(c) is that this is consistent with the threshold for the Commerce Commission's Capex Input Methodology (Capex) for major capital expenditure. For disclosure years 2013-2015, the threshold is $15m. The threshold increases to $20m from regulatory control period 2 (2015-2016).

7.9 A date of 10 October 2012 has been chosen as that was the date the Authority released the October 2012 issues paper, and it is reasonable to assume that parties took into account the possibility of the SPD charge applying to new investments from that date.

7.10 Currently, the investments that the simplified SPD charge would apply to, and for which SPD charges have been modelled in relation to, are:

- North Island Grid Upgrade (NIGU)[25]
- HVDC Pole 3 (HVDC and upgrade proposal)[26]
- HVDC Pole 2
- North Auckland and Northland (NAaN) project[27]
- Lower South Island (LSI) Renewables[28]
- Wairakei Ring[29]
- Otahuhu substation diversity project[30]
- UNI dynamic reactive support[31]
- LSI reliability[32]
- Upper South Island (USI) reactive support (IGE 4)[33]
- Bunnythorpe-Haywards (BPE-HAY) A and B lines conductor replacement (if this is approved by the Commerce Commission)[34]

7.11 The location of these investments is shown in Figure 3.

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[25] Available from http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/transpower-major-capital-proposal/amending-the-allowance-and-outputs-for-the-north-island-grid-upgrade-project/

[26] Available from http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/hvdc-grid-upgrade/

[27] Available from http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/north-auckland-and-northland-proposal-history/

[28] Available from http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-renewables/

[29] Available from http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2008-gup/wairakei-ring-economic-investment-history/

[30] Available from http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/transpower-major-capital-proposal/otahuhu-substation-diversity-project-mca-amendment-application/

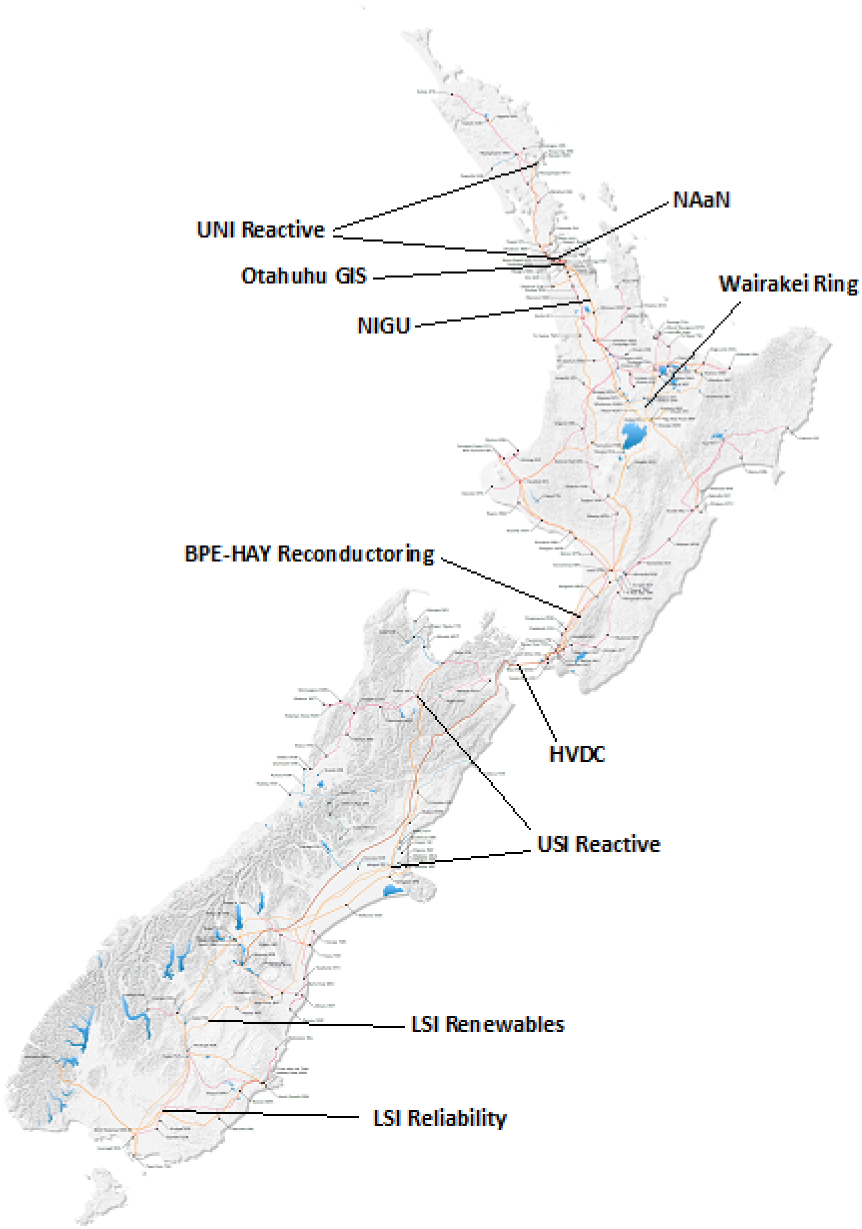
[31] Available from http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/upper-north-island-dynamic-reactive-support-investment-proposal-archive/

[32] Available from http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-reliability/

[33] Available from http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/grid-development-proposals-archive/ige-applications/upper-south-island-reactive-support-history/

[34] Available from http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/transpower-major-capital-proposal/bunnythorpe-haywards-a-and-b-lines-conductor-replacement-investment-proposal/

**Figure 3: Investments initially subject to SPD charged under simplified SPD charge proposal**




Source: Electricity Authority

### Identifying benefits ex post and applying the charge ex ante

7.12 Under the SPD charge proposed in the October 2012 issues paper, the SPD charge for a month would not be until after the end of the month because the charge depended on the wholesale market outcomes during that month. In other words, the proposal was to both calculate and apply the charge ex post. The rationale for this approach was to link transmission charges with actual benefits.

7.13 Some submitters considered that this approach would create too much uncertainty as parties would not know what their charges were until the month was complete.[35] Submitters considered that this uncertainty would lead to increased final prices as generators and retailers would price to mitigate the risk of unexpected adverse charges. Further, submitters considered that creation of uncertainty was inconsistent with the Authority's statutory objective because it would not promote efficient investment.

7.14 The alternative would be to calculate the charge ex post but apply the charge ex ante. This is the approach used under the existing TPM. For example, for the April 2014 pricing year the interconnection charge is based on RCPD for the period 1 September 2012 to 31 August 2013. Similarly, the HVDC charge for an April pricing year is calculated using historical anytime maximum injection in either the previous 12 month period between 1 September and 31 August or the immediately preceding 4 years, whichever is the higher.

7.15 Taking this approach would mean parties would know their transmission charges in advance and so could take the charges into account in setting their own prices.

7.16 The main disadvantage with this approach is that the price for a charging period may not reflect the actual benefit to the party from transmission investments subject to the SPD charge during the period. However, for efficient investment the accuracy of the price signal within the charging period is less important than the long run signal of the cost implications from a transmission investment. Accordingly, the Authority agrees with submitters that calculating the charge in one period and using this information to apply the charge in a future period is likely to be preferable. Options for the calculation and charging period are discussed later in this section.

**Modelling results and determination of parameters for simplified SPD charge**

7.17 The Authority has modelled all options discussed in this working paper using data for July-October 2012 inclusive. This time period was selected because it has several advantages:

(a) it includes both south HVDC transfer (in July) and north HVDC transfer (in October)

(b) it includes some relatively high peaks (in July/August) which should test the need for reliability investments

(c) it is reasonably short (less than a full year) so allowed more scenarios to be run across the data set in the time available, than would be the case if a longer time period was chosen

(d) it is quite recent

[35] e.g. Auckland Energy Consumers Trust.

(e) it did not feature any major changes to SPD or to the power system.

7.18 The results were converted into a 2017 scenario.[36]

***Overall incidence of simplified SPD charges***

7.19 The overall initial incidence[37] of simplified SPD charges for the modelling period for generation and load is shown in Figure 4. These results were undertaken calculating benefit on a gross benefit basis and capping the amount that could be recovered from beneficiaries in any single day to no more than the daily share of annualised costs of the investment.

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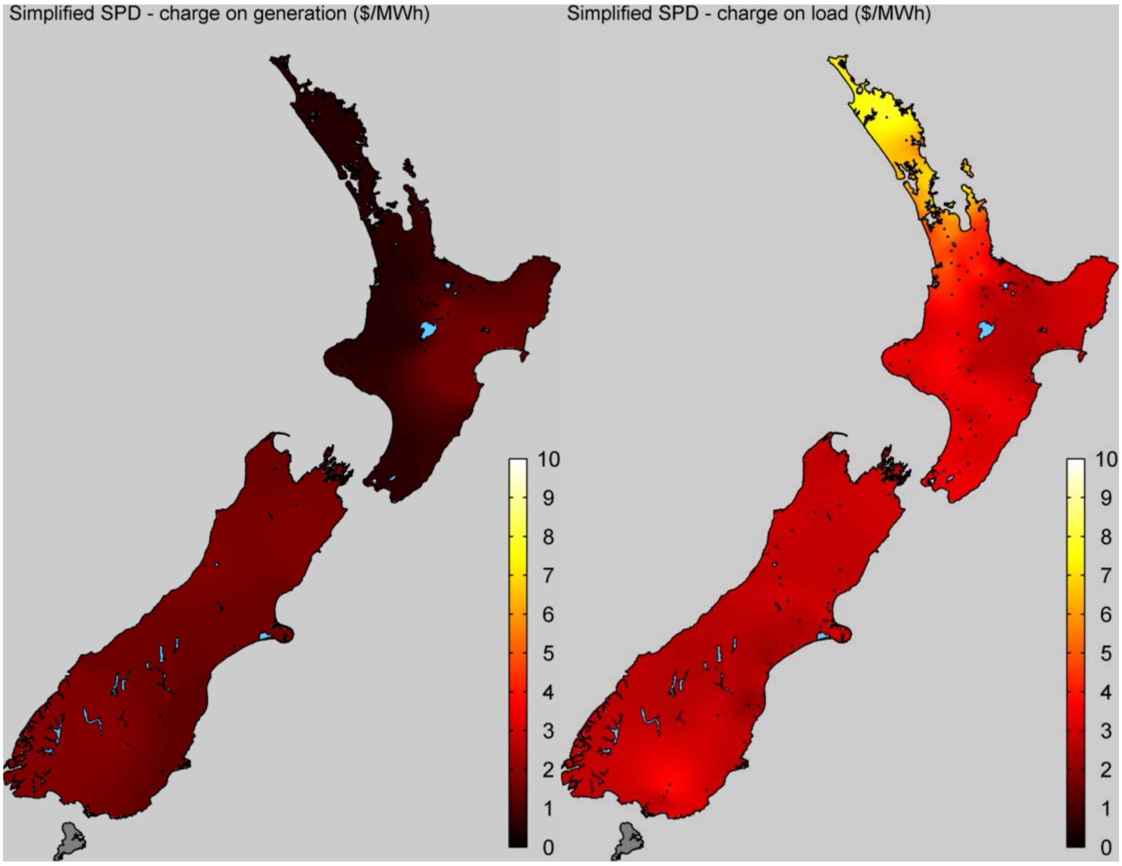
[36] This involved:

- increasing demand by 7% at all nodes (except Tiwai, where demand is not scaled, and Kawerau, where demand is scaled down)
- removing one coal-fired Huntly unit, leaving just two coal-fired units remaining
- adding Te Mihi geothermal (105 MW after derating), Ngatamariki geothermal (75 MW after derating, as close as possible to the actual location), Mill Creek wind (mean 25 MW, proportional to West Wind), and the McKee peaker (100 MW, replicating the offers of one of the Stratford peakers)
- using the network configuration from 31 July 2013
- updating the network configuration to reflect the availability of all 9 AC investments (assuming no outages on new circuits, and using winter line ratings at all times)
- adjusting IR requirements to reflect the availability of the bipole HVDC
- turning off all group constraints.

[37] Note, in this paper “incidence” only refers to the initial incidence of charges. This paper does not consider the economic incidence of charges, which would be affected by the extent of pass-through of charges.

**Figure 4: Overall incidence of simplified SPD method**




Source: Electricity Authority

7.20 Figure 4 shows that the simplified SPD method would result in a greater concentration of charges on load than generation.

7.21 Charges are highest for the upper North Island load – in this sample around $6-$7/MWh, with most other load paying $2.50-$4/MWh. The reason for this is upper North Island loads are the principal beneficiaries of two of the most expensive investments – NIGU (approved cost $824m[38,39]) and NAaN (total investment cost $415m). The distribution of charges for NIGU and NAaN are shown in Figure 36 and Figure 37 in Appendix C.

7.22 Charges to generation are lower than charges to load. The charge to generation is no more than about $2/MWh for this sample period, which would be paid by some South Island and eastern central North Island generators. The reason for the higher charges to South Island generators is they are the principal generator beneficiaries of Pole 2 and Pole 3 of the HVDC (total investment cost $200m and $672m respectively) and lower South Island generators are the principal generator beneficiaries of the LSI Renewables project (total investment cost

[38] Costs of transmission investments in this working paper are nominal, unless other indicated.

[39] The Authority understands that Transpower has applied to the Commerce Commission to increase its approved allowance for NIGU up to $894m, and that the Commerce Commission is currently consulting on this request.

$190.6m). Eastern central North Island generators would experience higher charges because they are the principal beneficiaries of the Wairakei Ring Project (total investment cost $131m). The distribution of charges for Pole 2, Pole 3, LSI Renewables and the Wairakei Ring are shown in Figure 38 to Figure 41 in Appendix C. All generation pays some transmission charges – even generation in the upper North Island, which benefits the least from the transmission investments modelled, would face charges of about $0.60/MWh.

7.23 This distribution of charges is similar to distribution of charges under the original SPD proposal, as shown in Figure 45 in Appendix C. However, charges are generally higher under the simplified SPD charge as a result of daily rather than half-hourly capping. This means that more costs would be recovered from beneficiaries under the simplified SPD charge. Based on the modelling undertaken and the period investigated, the simplified SPD charge (with daily capping) would recover about $221m per annum compared to about $165m per annum that would be recoverable under the SPD charge proposed in the October 2012 issues paper.

7.24 The important point to note from the overall distribution of charges is that it reflects the benefit from the investments and the cost of the investments. If a new investment is undertaken, this would alter the overall distribution of charges, reflecting the benefit received from the investment.

7.25 For example, if a large investment were undertaken in the upper South Island, and if the beneficiaries of the investment were upper South Island loads, this would be reflected in SPD charges to those parties. Further, the distribution of charges would be specific to the benefit received at each node. If the charge was applied, prospective beneficiaries would therefore need to take into account the cost involved in paying for the investment in their own investment decisions. This would promote more efficient investment than the current interconnection charge, where a new investment would result in an increase in interconnection charges for *all* interconnection customers.

***Gross versus net benefit charging***

7.26 In the 2012 proposal, the SPD charge was calculated according to only the positive benefits a party received from an investment. The charge did not take into account any negative benefits (disbenefits) to the party. This form of charging can be referred to as “gross benefit” charging. This approach means a party would have to pay the SPD charge even though the transmission investment for which the charge was calculated would make them worse off in net terms.

7.27 Examples of parties that may experience disbenefits of a transmission investment are:

(a) a generator that faces a lower wholesale price as a result of a transmission investment

(b) load that faces a higher wholesale price as a result of a transmission investment.

7.28 Submitters considered that charging according to gross benefit was inconsistent with promoting efficient investment because when an investor was considering whether to make an investment the investor's decision to proceed would depend on the net benefits they expected to receive from the investment – that is, positive benefits less disbenefits. These submitters therefore considered that if the SPD charge was introduced it should be calculated on a net benefits basis – positive benefits less disbenefits.

7.29 There are two ways to apply net benefits charging:

(a) charging only those parties that receive positive net benefits from the investment ("net benefits only, or NBO"), or

(b) charging only those parties that receive positive net benefits and compensating or refunding those parties that experience net disbenefits ("net benefits with refund, or NBR"). This is analogous to the situation with GST where application of the 15% GST rate to situations where payments exceed receipts results in a refund or compensation.

7.30 Under the NBO approach, benefits and disbenefits are summed over the charging period[40]. Where a party experiences net benefits the party would be subject to an SPD charge that reflects the level of net benefits to a party. However, where a party experiences net disbenefits, they would not be subject to an SPD charge for the charging period.

7.31 The main advantages of the NBO approach compared with the gross benefits and the NBR approach are that:

(a) it is consistent with the approach taken to many investments in that disbeneficiaries from an investment do not often receive compensation, except where the investment impinges on their property rights, which would not be the case for transmission customers

(b) it is self-funding as no funding is required to compensate disbeneficiaries.

7.32 The main disadvantages of the NBO approach compared with the gross benefits and the NBR approach are:

(a) to the extent that parties are charged in net terms for their generation and load it provides incentives for inefficient vertical integration to avoid the charge. This is because when a generator experiences disbenefits from an investment a load party at the same location is likely to experience benefits. If parties are allowed to offset benefits against disbenefits vertical integration would allow them to minimise their SPD charge. Vertical

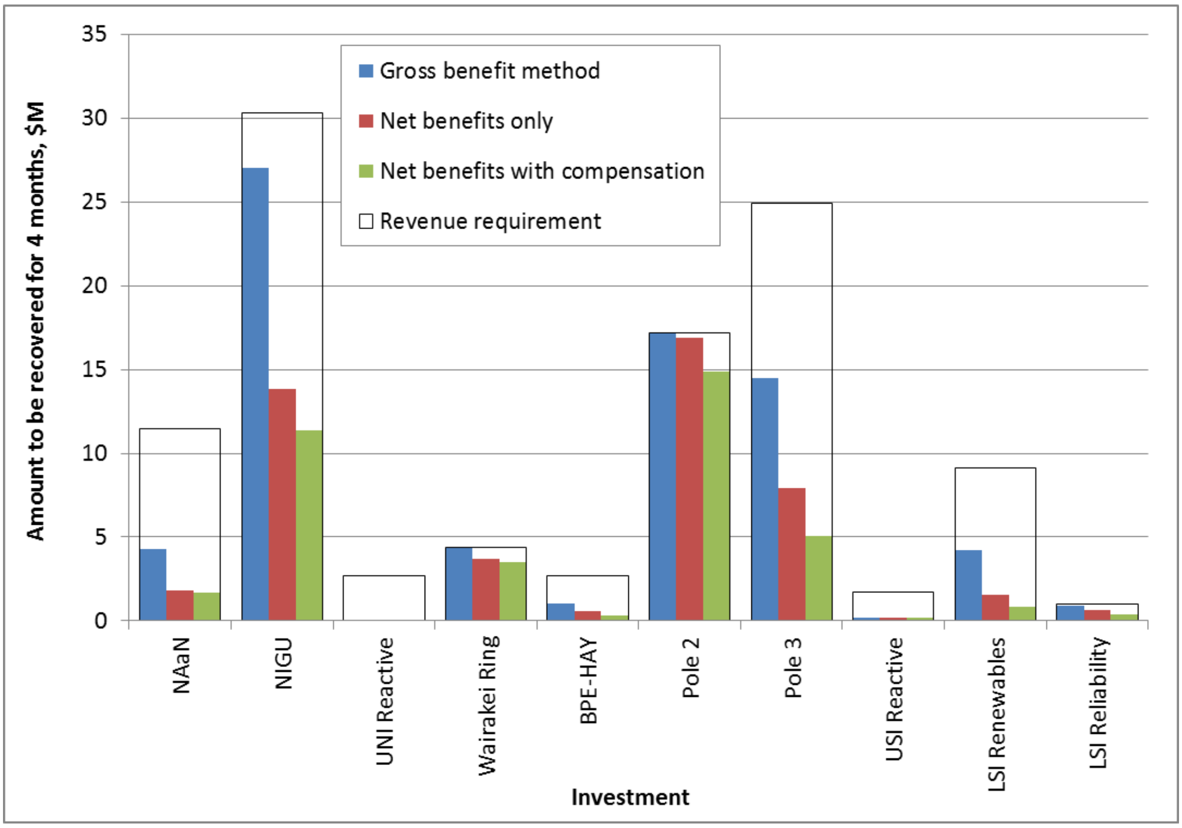
[40] Note that in the modelling presented below benefits and disbenefits are summed over the capping period – usually daily.

integration is likely to be detrimental to retail competition as parties would have incentives to withdraw from retailing in areas where they do not have generation

(b) it results in less of the costs of the investment recovered from beneficiaries than the gross benefit approach as shown in Figure 5.

7.33 Because of the incentives for inefficient vertical integration, and the adverse impact this could have on competition, the Authority considers that the costs of applying the SPD charge on a net benefits only basis are likely to exceed the benefits.

**Figure 5: Net versus gross benefit charging (with SPD charges calculated using daily capping)**




Source: Electricity Authority

7.34 Under the NBR approach, benefits and disbenefits would be summed over the charging period. As with the net benefits only approach, net beneficiaries would be subject to an SPD charge that reflects the level of net benefits they receive from an investment. However, net disbeneficiaries would receive compensation reflecting their net disbenefit from the investment.

7.35 There are two possible sources of funding for compensation to net disbeneficiaries:

(a) beneficiaries of the investment:

In particular, to the extent their benefit from an investment exceeded the costs of the investment beneficiaries could be charged so as to compensate disbeneficiaries. Provided the combined cost of the charge for the investment itself plus their contribution to the costs of compensating disbeneficiaries did not exceed their private benefits from the investment, they would be at least as well off in net terms.

(b) the residual charge.

7.36 Of these two possible sources of funding, the Authority considers that the residual charge is likely to be preferable. The main reason for this is that funding compensation from beneficiaries will increase the charges they face, which in turn will increase their incentives to act inefficiently to avoid the charge to the extent that they can. While this is also the case with the residual charge, provided this is charged over a broader base the incentive for inefficient charge avoidance should be lower.

7.37 The main advantages of the NBR approach to the gross benefits and NBO approach are:

(a) the compensation means that parties made worse off by the investment:

(i) continue to have incentives to invest as if they are no worse off as a result of the investment

(ii) do not have inefficient incentives for vertical integration to avoid the charge, as this would result in reduced compensation

(b) the approach is consistent with the approach taken to investments where parties are charged only when they receive net benefits from the investment and parties made worse off from the investment are compensated.

7.38 The main disadvantages of the NBR approach are:

(a) a source of funding is required to provide compensation to disbeneficiaries, this will raise charges for other parties.[41] This may:

(i) increase incentives for inefficient avoidance of charges to the extent parties have the ability to do this

(ii) potentially increase allocative inefficiency to the extent that the compensation costs are funded by charging non-beneficiaries through the residual charge

(b) it results in less of the costs of the investment recovered from beneficiaries compared with both the gross benefits and net benefits only approaches, as shown in Figure 5.

[41] LCE is a possible source of funding for this but it may cause other potential problems – e.g. giving LCE (which would in effect involve pre-allocated FTRs) to downstream generators may give them incentives to act to cause constraints to maximise their FTR payout and discourage entry, which would be detrimental to competition.

7.39 The Authority considers that the NBR approach is likely to be superior to the NBO approach. This is because it preserves incentives for efficient investment and does not suffer from providing inefficient incentives for vertical integration and therefore would not have consequent adverse impacts on competition.

7.40 Overall, the judgement of which of the gross benefits approach and NBR approach is superior depends on weighing up:

(a) greater recovery of costs of investments from beneficiaries under the gross benefits approach

(b) preservation of incentives for investment under the NBR approach compared with the disincentives for investment under the gross benefits approach since disbeneficiaries would be made worse off

(c) likely lower charges to each party under the gross benefits approach (since costs would be recovered from a broader base and no funding for compensation is required), which would lower incentives for inefficient avoidance of the charge

(d) potential allocative inefficiency under the NBR approach if compensation costs were recovered through the residual charge.

7.41 The Authority's preliminary view is that the gross benefits approach is superior. This is because the costs of the NBR approach are likely to be higher. The risk of investment in generation or load being undermined by a transmission investment is a matter that parties making investments are likely to take in their investment decisions, as it is equivalent to the risk of new entry undermining an investment. The Authority notes that parties made worse off as a result of competition from imports as a result of a trade agreement, for example, are not normally compensated.

***Maximum cost recovery period – capping***

7.42 In the proposal in the October 2012 issues paper, the Authority proposed that the revenue recovered within a trading period in relation to an investment through the SPD charge would be limited to the half hourly share of the annualised costs of the investment. The reason for this approach was to limit the extent to which a high proportion of the costs of an investment could be recovered in a single trading period. This would limit the size of the charge in any one trading period and therefore limit incentives for inefficient avoidance of the charge.

7.43 Some submitters considered that this approach undermined achievement of beneficiaries-pay, as it limited the extent of recovery of costs from beneficiaries. This was likely to be the case particularly for investments aimed at improving reliability. For these investments the limit (or "cap") meant only partial recovery of the costs from beneficiaries during periods when the absence of the investment would mean electricity was not supplied. Since the actual need for such investments is likely to be infrequent the SPD method implies recovery of the costs of these investments in only a few trading periods but the half hourly cap limited the extent of cost recovery.

7.44 The Authority has therefore investigated allowing a greater proportion of annual costs to be recovered before a cap applies. In particular, the Authority has investigated limiting the proportion of annual costs of an investment that can be recovered in a period to the proportion of a year corresponding with that period:

(a) daily

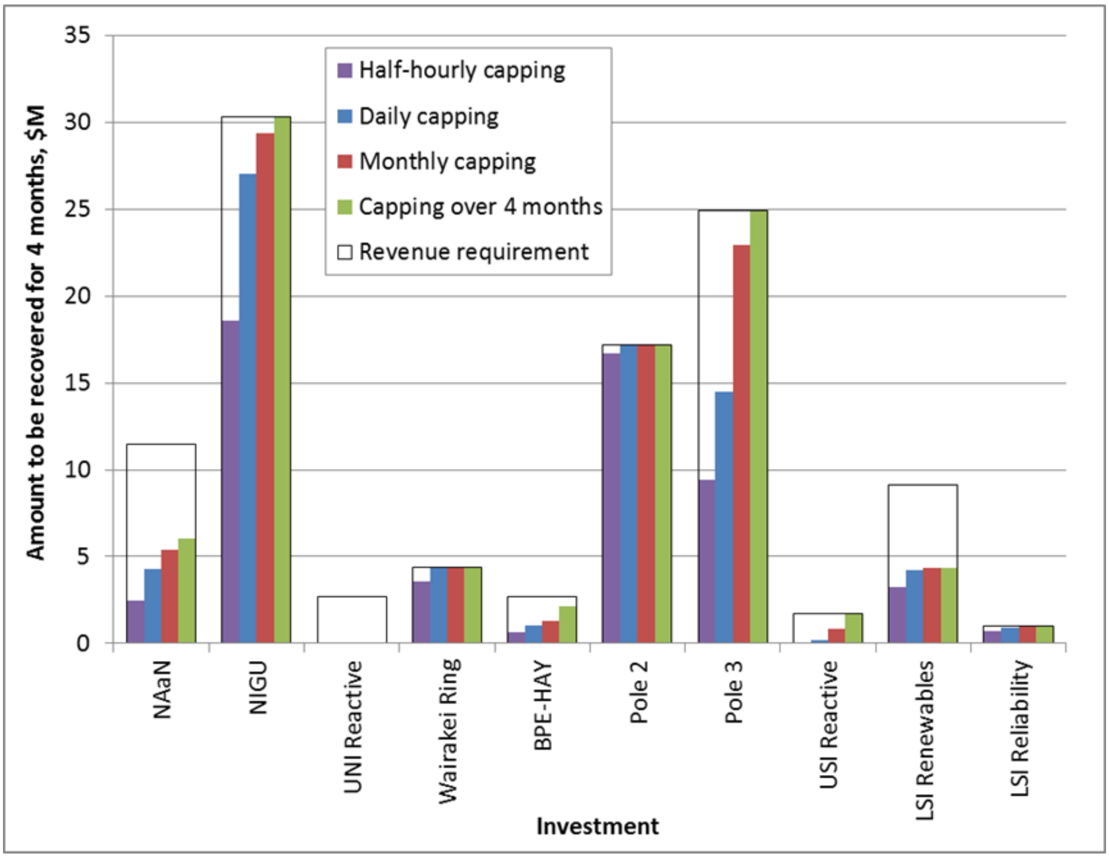
(b) monthly

(c) 4 monthly.

7.45 For example, a daily cap would limit the costs that can be recovered in one day to 1/365$^{th}$ of the annual costs of an investment, while a monthly cap would limit the costs that can be recovered in one month to 1/12$^{th}$ of the annual costs of an investment.

7.46 The impact of the capping period on the extent of recovery of the costs of the investments subject to the simplified SPD charge is shown in Figure 6.

**Figure 6: Effect of capping period on revenue recovery. SPD charges calculated using gross benefit**




Source: Electricity Authority

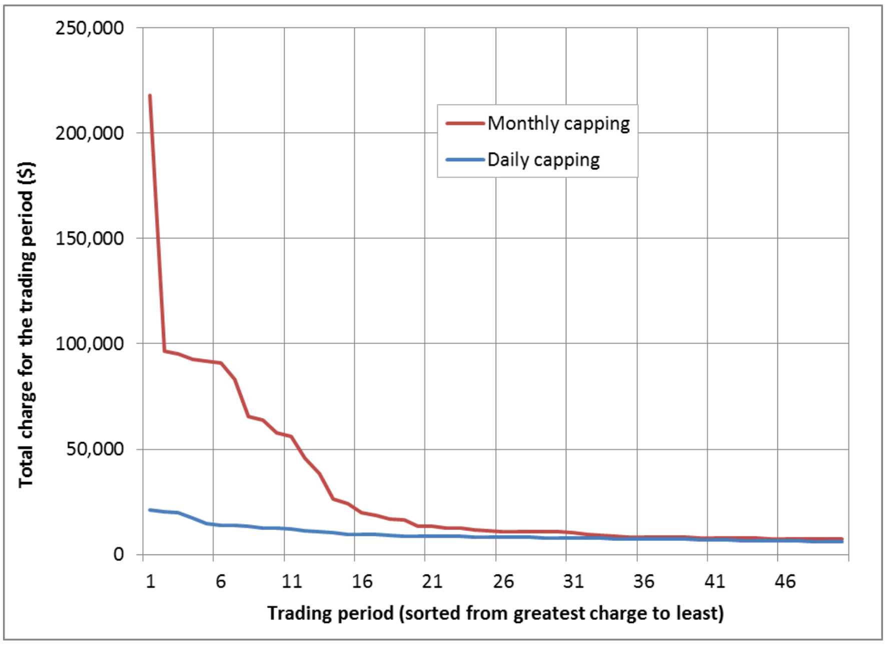
7.47 Figure 6 shows that lengthening the capping period increases the revenue recovered. However, once the full revenue requirement is reached further increases in the capping period may only alter the incidence of the charge, limiting the extent to which costs are recovered from parties that benefit from the investment as a result of it preventing non-supply or providing significant benefit during periods of significant congestion.

7.48 On this basis, a longer capping period is preferable to a shorter capping period. Against this, however, is the fact that a longer capping period implies potentially higher charges in an individual trading period. Higher charges will increase the incentive to avoid the charge for the parties that have the ability to take actions to do this. As several parties pointed out in submissions, some generators may be able to alter their offer curves to minimise their charge and shift the burden of the charge on to load and generators unable to alter their offers. Further, having a high price when there is non-supply means generators that are able to alter their offers may have a greater ability and incentive to shift the costs of transmission onto load.

7.49 A balance therefore needs to be struck between having a sufficiently long capping period that costs are recovered from beneficiaries but not having it so long as to provide excessive incentives for avoidance of the charge. Figure 6 shows that, except for Pole 3, there is not a significant difference in the cost recovery under daily capping versus monthly capping. Further, for the investments with significant benefits as determined by the simplified SPD method – Pole 2, the Wairakei Ring, and LSI reliability – full costs are recovered or almost recovered under daily capping.

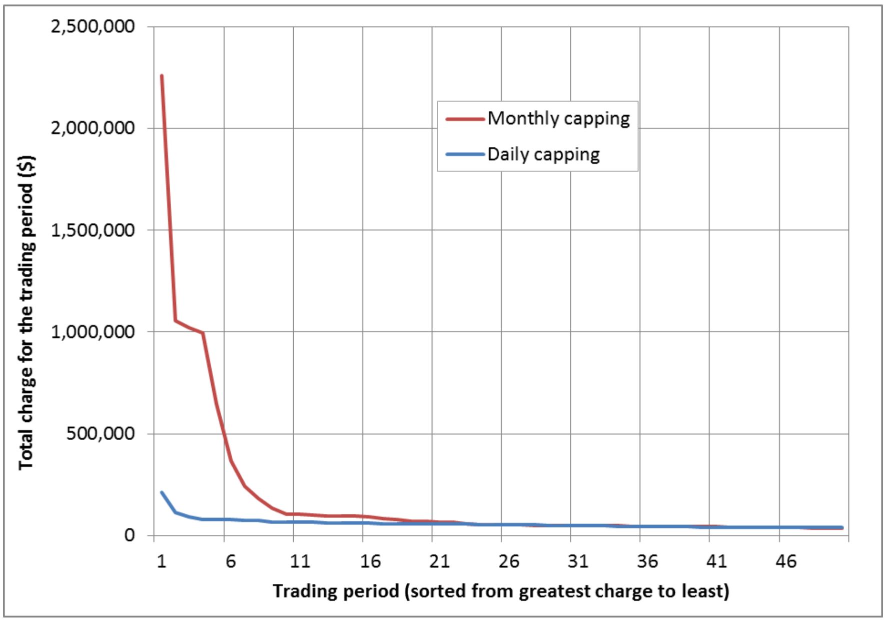
7.50 To investigate the extent to which the different capping periods might provide incentives for inefficient behaviour to avoid the charge, the Authority examined the extent to which costs were recovered in a limited number of periods. Figure 7 to Figure 9 show the number of trading periods in which a large proportion of costs were recovered for the Wairakei Ring, NIGU and Pole 3.

## Figure 7: Charges in top 50 trading periods – Wairakei Ring



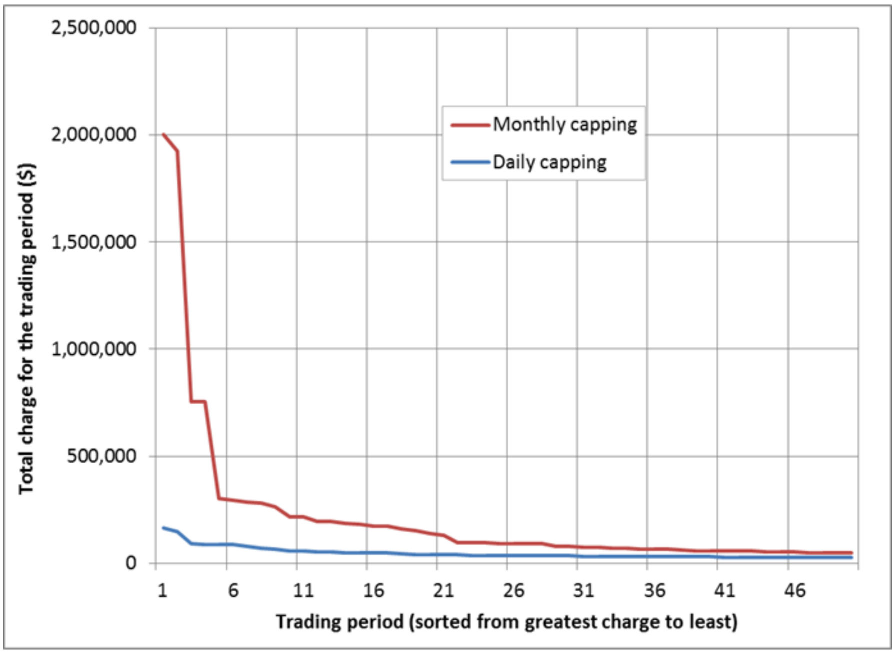

Source: Electricity Authority

## Figure 8: Charges in top 50 trading periods – NIGU




Source: Electricity Authority

**Figure 9: Charges in top 50 trading periods – Pole 3**




Source: Electricity Authority

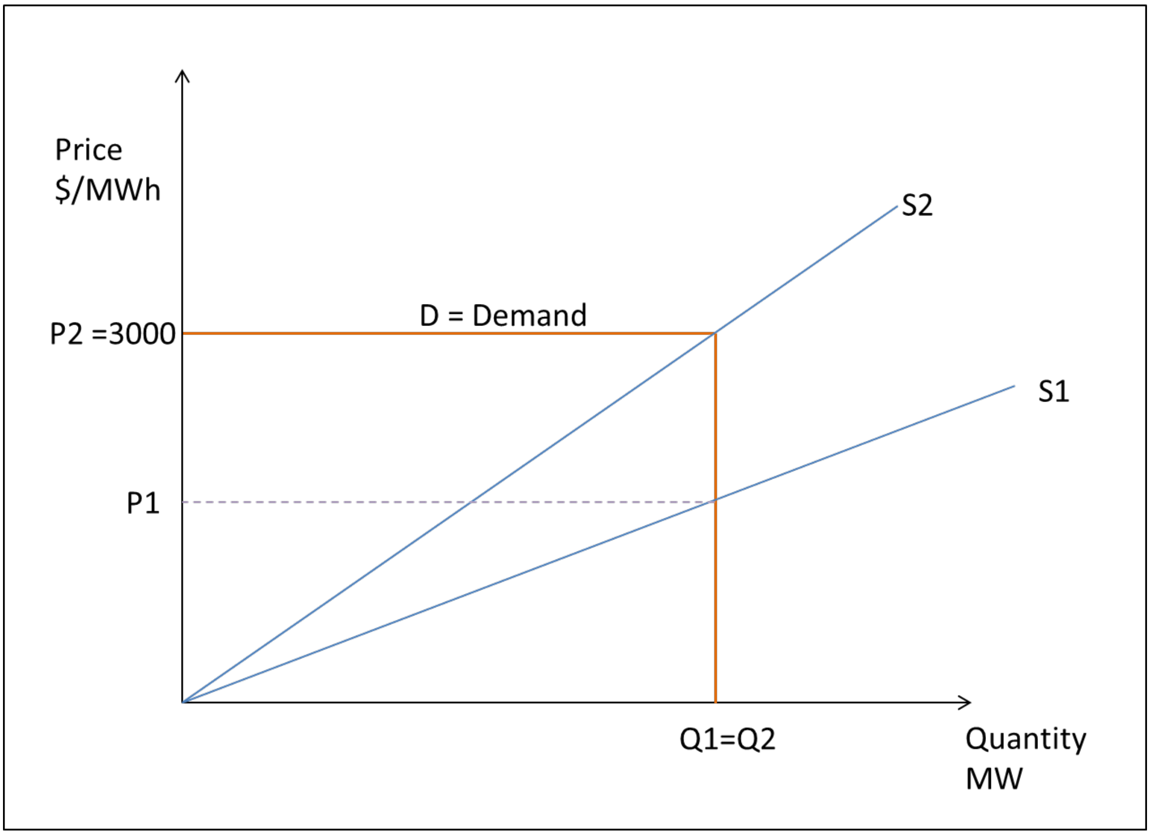
7.51 These figures show that with monthly capping there are a few trading periods for which a large amount of revenue is recovered. These are typically periods with a high price in the counterfactual. (Some of these periods have high charges because the price for non-supply applies in the counterfactual. In particular, for the Wairakei Ring this was the case for 10 of the top 50 trading periods, for NIGU 4 of the top 50 trading periods, and for Pole 3, 2 of the top 50 trading periods.) By extension, four-monthly capping is likely to be worse. However, with daily capping no single trading period has such a strong influence on cost recovery. This suggests that incentives on participants to alter their behaviour in response to the charge are likely to be significantly stronger for monthly capping than daily capping.

7.52 In conclusion, the preferred approach to capping appears to be daily capping rather than half-hourly, monthly or four-monthly capping. This is because daily capping achieves the best balance of cost recovery from beneficiaries and would limit incentives for parties to inefficiently alter their behaviour to avoid the charge.

***Treatment of demand side response***

7.53 Several submitters considered that the assumption in the SPD charge proposal in the October 2012 issues paper of no response by demand to wholesale prices (perfectly price inelastic demand) did not reflect reality given that some consumers alter their load in response to relatively high wholesale prices. The demand curve that was used in the October 2012 issues paper proposal is illustrated in Figure 10.

**Figure 10: Illustration of demand curve in 2012 SPD charge proposal**




Source: Electricity Authority

7.54 Figure 10 shows a supply curve, S1, for the SPD market solve, supply curve, S2, for the SPD counterfactual solve with the relevant investment removed, and a demand curve, D. In this example, the market solve results in a price P1, while removal of the investment results in non-supply, which means a price, P2, of $3000/MWh would apply. The demand curve, D, is vertical up to the point of non-supply, implying demand is perfectly inelastic, then horizontal at the point of non-supply.

7.55 Submitters considered that the demand assumption meant that load would bear a higher proportion of overall charges than was appropriate. Further, some considered that the assumption of no demand response exacerbated incentives on generators to alter their offers to force loads to bear the SPD charge. These submitters therefore considered that the Authority should investigate applying the SPD charge that incorporated the possibility that demand should respond to the wholesale price.

7.56 The Authority has investigated the extent to which load responds to the wholesale price. The relationship between wholesale prices and load is shown for some large loads and at a selection of mass market nodes in Appendix D, along with a detailed discussion of the response to wholesale prices at these nodes.

7.57 Appendix D shows that while some large loads clearly reduce their load in response to wholesale prices, the mass market load does not appear to respond to wholesale prices in the short run.

7.58 Further, with dispatchable demand set to become operative in the wholesale market from 2014,[42] dispatchable demand will be a feature of the wholesale market by the time any amendment to the TPM is introduced. The SPD charge therefore needs to reflect the reality that some demand, at least, is and will be responsive to price.

7.59 The Authority has therefore investigated three possible approaches for incorporating demand side response into the SPD method:

(a) applying a cost of non-supply of $3000/MWh, plus applying a demand curve based on actual price-responsive bids into the Price Responsive Schedule (PRS) and dispatchable demand bids

(b) applying a cost of non-supply of $3000/MWh, plus price-responsive bids of $200/MWh at specified quantities at industrial nodes where price response has been observed in the past

For the purpose of modelling this option the following bid quantities were used at the following nodes (except where the bid quantity would exceed actual load): 15 MW at Kawerau (KAW), 15 MW at Whirinaki (WHI), 8 MW at Glenbrook (GLN), 5 MW at Kinleith (KIN)

(c) applying a cost of non-supply of $3000/MWh, plus 2.5% of actual load at each node bid at $200/MWh and 10% of actual load at each node bid at $1000/MWh. (This crudely represents a short-term elasticity of demand of -0.01. [43])

7.60 The Authority considers that option (a) should only be used if price responsive bids result in actual dispatch. Otherwise, the incentive on loads would be to overstate their response to high prices in their bids in order to avoid the transmission charge. Dispatchable demand bids would be subject to dispatch.

7.61 In relation to option (b), further analysis would be required to determine appropriate bid quantities at price responsive nodes. The approach would also need to ensure that it did not result in inefficient behaviour to avoid the charge. A possible approach would be to base the demand response assumption on historical responses that affected loads could not influence or using an average response over a long period, for example 5 years.

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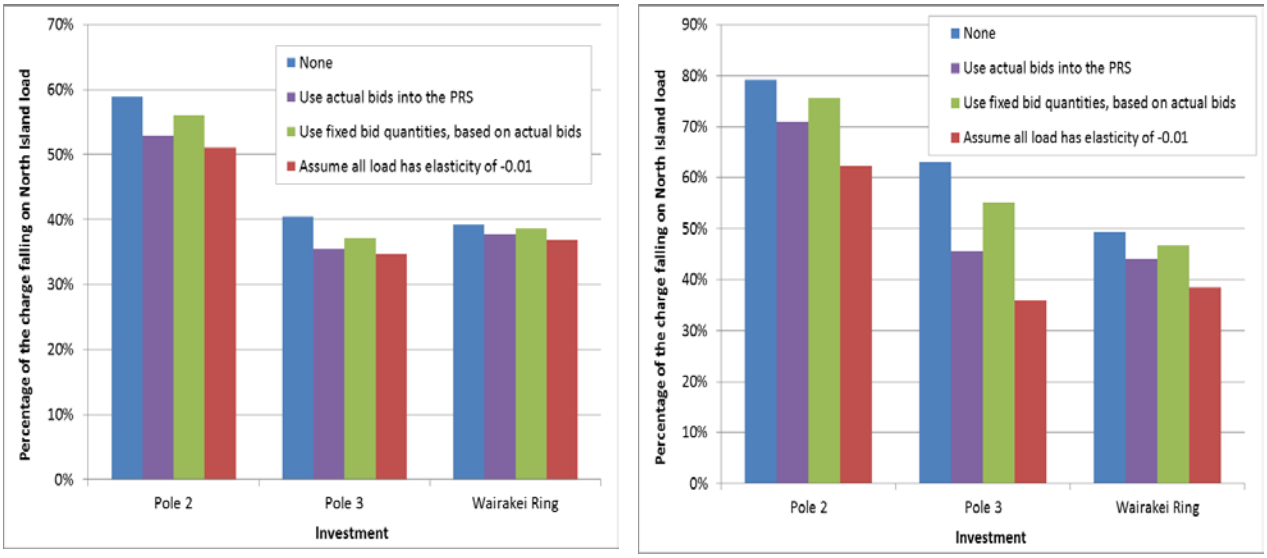
[42] http://www.ea.govt.nz/development/work-programme/wholesale/dispatchable-demand/

[43] Assuming the normal mean spot price is $70/MWh, then a price of $200/MWh is roughly 200% above normal: the corresponding change in demand is -0.01 x 200% or a 2% reduction. A price of $1000/MWh is 1300% above normal: the corresponding change in demand is -0.02 x 1300% or a 13% reduction. Of this reduction, 2% has already been accessed at $200/MWh, leaving 11% - here rounded to 10% for simplicity.

7.62 In relation to (c), the assumption of a short-term elasticity of demand of -0.01 is not unreasonable given the degree of penetration of advanced metering, which would give consumers an increasing ability to alter their demand in response to price signals. Further, at least some commercial consumers receive spot pricing signals to some degree. Empirical analysis could be undertaken to determine the appropriate demand elasticity to be applied if the TPM were amended to introduce the SPD charge.

7.63 The results from the alternative approaches for treatment of demand-side response under both daily and monthly capping (with SPD charges calculated using gross benefit) are shown in Figure 11 below.

**Figure 11: Incidence of SPD charges on North Island load under different approaches to demand response for daily capping (left) and monthly capping (right)** [44]




Source: Electricity Authority

7.64 Figure 11 shows that altering the assumptions regarding demand response results in a reduced proportion of charges falling on North Island load. The percentage reduction is lower under daily capping than monthly capping.

7.65 To investigate the extent to which the different approaches to demand response might reflect actual benefit the Authority investigated the impact of deprival of the HVDC on a price responsive load (Norske Skog). The effect of the different approaches to price response on prices in the counterfactual (deprival of the HVDC) for trading period 21 of 9 July is shown in Figure 12.

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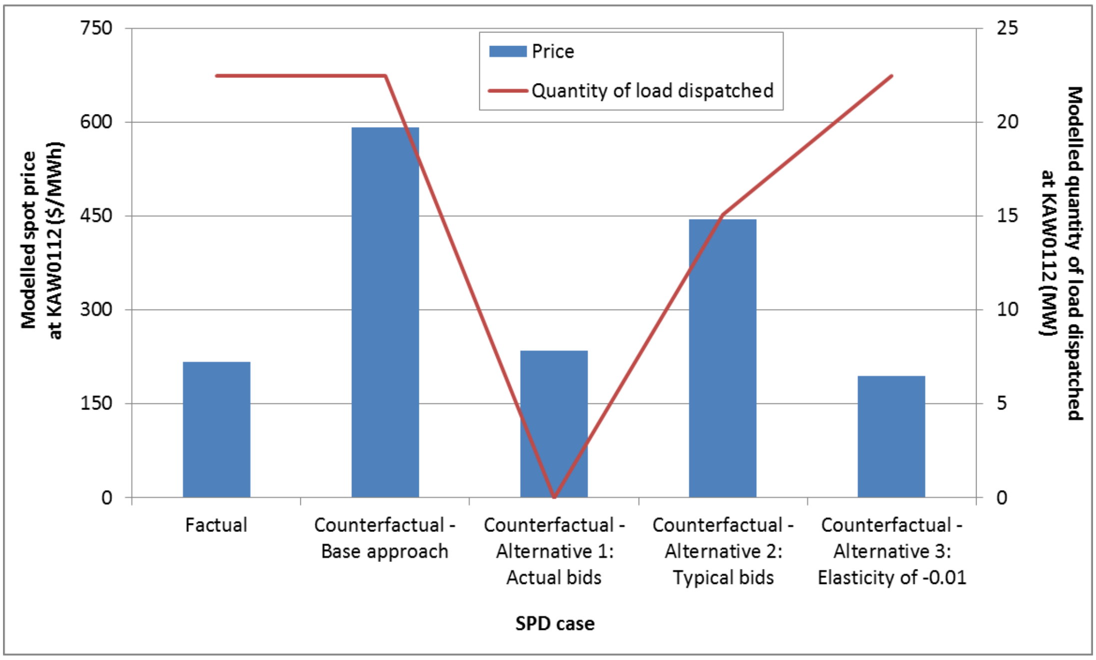
[44] This analysis was carried out on the basis that demand-side response would be available at all times. For subsequent work, it would be preferable to assume that once prices in the factual exceed the demand-side bid price, the demand-side response has already been dispatched in the factual and is no longer available in the counterfactual.

7.66 Figure 12 shows that deprival of the HVDC pushes up simulated prices in the counterfactual. However, incorporating demand response into the SPD method reduces prices in the counterfactual solve while also reducing load. Of the different approaches, using actual bids results in the greatest reduction in dispatch, while assuming a price elasticity of demand of -0.01 for all demand results in the greatest reduction in modelled price but has little effect on the quantity of demand dispatched.

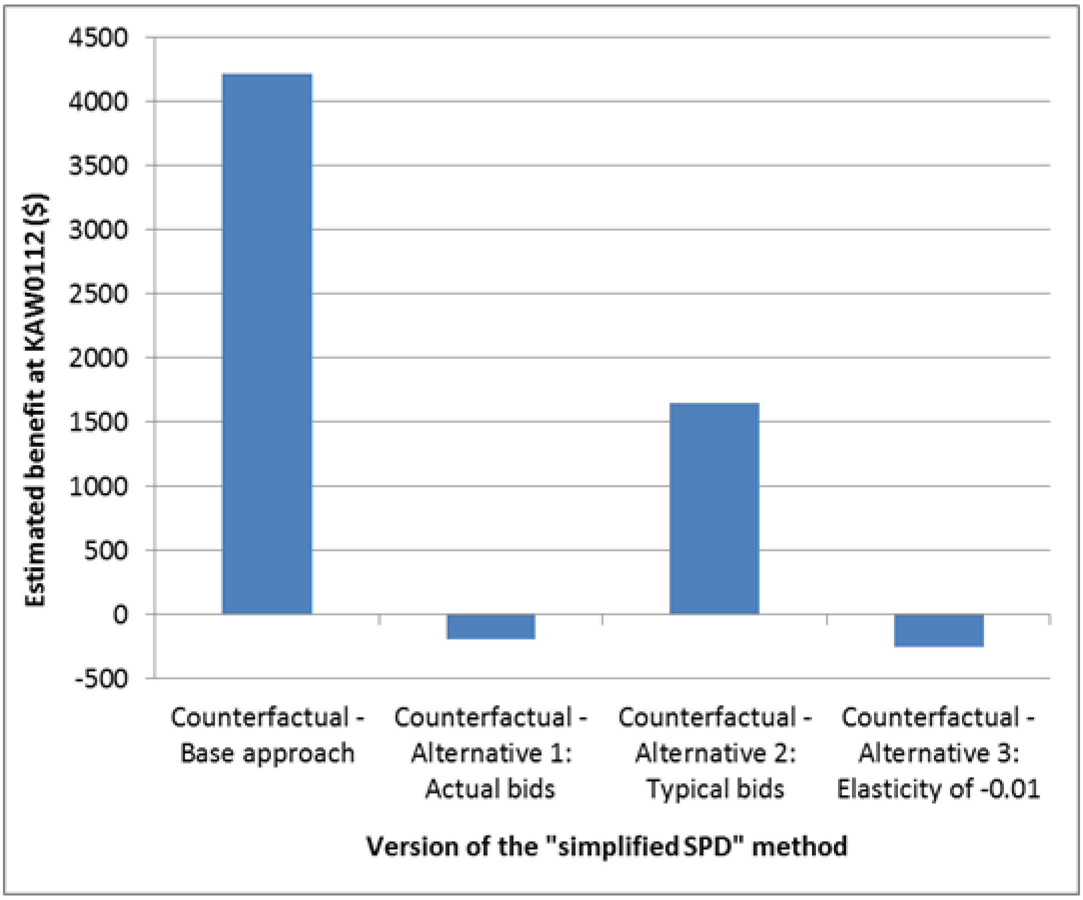
**Figure 12: Impact of approach to demand response in SPD method on prices in counterfactual for KAW0112 for trading period 21 of 9 July 2013**




Source: Electricity Authority

7.67 The effect of the different approaches to demand response on the estimation of benefit to Norske Skog under deprival of the HVDC in this same trading period are shown in Figure 13.

**Figure 13: Impact of approach to demand response in SPD method on estimates of the benefit from the HVDC link at KAW0112 for trading period 21 on 9 July 2013**




Source: Electricity Authority

7.68 Figure 13 shows that if demand side response was not modelled in the SPD method, Norske Skog would be considered to benefit significantly from the HVDC link in this trading period. However, including demand response in the SPD method results in a substantial reduction in the estimated benefit from the HVDC. In the case of using actual bids and assuming an elasticity of demand of -0.01 the HVDC is shown to have a small disbenefit to Norske Skog in this trading period.[45]

7.69 Incorporation of demand response into the SPD method can have a significant impact on the estimated benefit to price responsive load from transmission investment. Given that dispatchable demand is expected to be in place by the time any changes to the TPM are introduced, the Authority's view is that dispatchable demand bids should be used to calculate the SPD charge if it is part of any changes to the TPM.

[45] This may be an artefact of the approach used – under which demand-side bids are included in the counterfactual at all times. Removing demand-side bids from the counterfactual when prices in the factual exceed the bid price may remove these negative estimated benefits.

7.70 For other demand that is not subject to dispatchable demand, an assumption of a demand elasticity of -0.01 seems reasonable given the significant penetration of advanced meters and the potential this provides for greater response by retail customers to wholesale prices. However, ideally the assumed elasticity of demand for load not subject to dispatchable demand should be determined through empirical estimation.

***Price for non-supply in SPD solve when investment is removed***

7.71 Another demand assumption of the SPD charge is the price of non-supply in the counterfactual. Some submitters considered that the assumption of a $3000 price for non-supply resulted in transmission charges that overstated the benefit of the investment to consumers from transmission investment and understated the benefit to producers.[46]

7.72 The $3000 price was based on the LRMC of a diesel peaker with a capacity factor of approximately 0.85%. In its submission on the October 2012 issues paper, Vector submitted that if Transpower and the Commerce Commission "used the diesel generation assumption when assessing grid investment proposals and options it would result in a substantially gold-plated network"[47]. This suggests that assuming this price for all nodes may not result in transmission charges that promote efficient investment.

7.73 The cost that should apply for non-supply is the LRMC of the transmission alternative that would have been built if the transmission investment in question had not been built. This is because in the absence of the transmission investment it is reasonable to assume that such an investment would have been made to minimise the risk of, or avoid, non-supply. The benefit estimate needs to take this possibility into account otherwise it would overstate the benefit. This working paper therefore investigates applying a cost of non-supply to reflect a cost of the transmission alternative if the transmission investment for which the SPD charge is being calculated had not been made.

7.74 The approach now being investigated by the Authority is to:

(a) calculate for each investment the amount of non-supply that would occur with the investment removed (ie what the SPD counterfactual is if the cost of non-supply was the same at all nodes)

(b) convert the amount of non-supply into a capacity factor

(c) set standard prices for non-supply at each node based on the implicit capacity factor

(d) the SPD charge would then be calculated for the investment using:

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[46] For example, Vector, Submission to the Electricity Authority on Transmission Pricing Methodology: Issues and proposals, paragraphs 70-73, page 13.

[47] *Ibid.,* footnote 19, page 13.

(i) a low price for non-supply across the grid where the implicit capacity factor was high, reflecting that if the investment had not proceeded high capacity factor generation such as a combined cycle gas turbine would have been required

(ii) a high price for non-supply across the grid where the implicit capacity factor was low, reflecting that low capacity factor generation, e.g. a diesel peaker, would have been required in the absence of the transmission investment.

7.75 The Authority's investigations revealed that for most investments modelled non-supply was infrequent (typically equivalent to a capacity factor of well under 1%) even without the upgrade. For these investments, a price for non-supply of $3000/MWh seems appropriate.

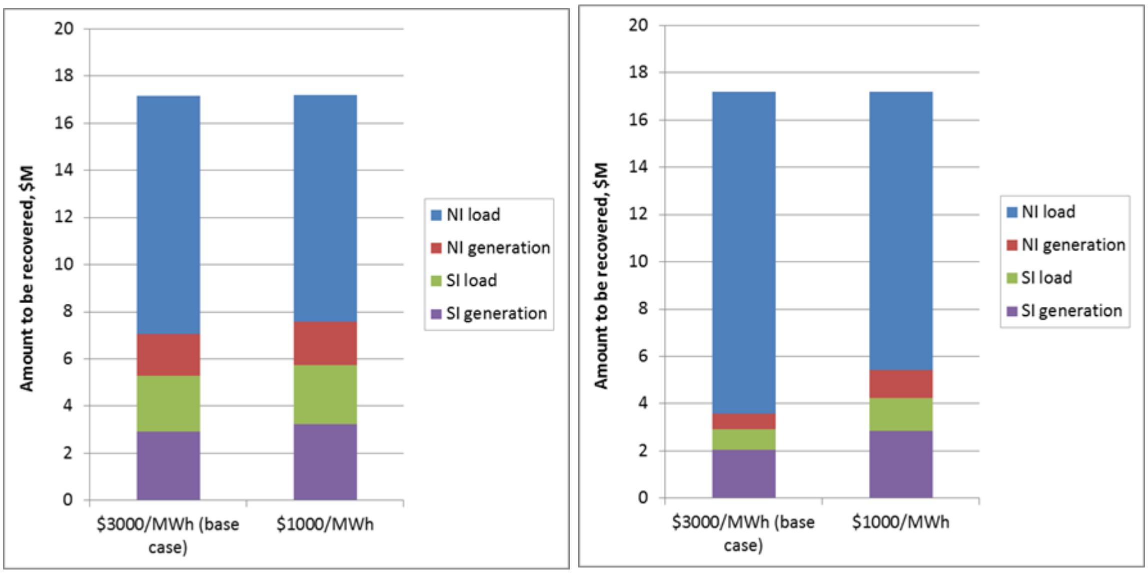
7.76 The exception to this was Pole 2, where non-supply occurs in 3% of trading periods without the investment. A price for non-supply of $1000 is therefore proposed, as this reflects the approximate LRMC of a thermal peaker (gas or oil) operating at a load factor of 3%.

7.77 The incidence of SPD charges for Pole 2 where the price for non-supply is $3000/MWh and $1000/MWh is shown in Figure 14 under daily and monthly capping of the SPD charge (calculated using gross benefit).

7.78 Figure 14 shows that a lower price of $1000/MWh for non-supply, rather than $3000/MWh, means generators pay more of the costs of Pole 2 than load. Daily capping further limits the amount paid by load compared with generation.

7.79 On the basis of the Authority's investigation into the incidence of non-supply for the investments investigated, the Authority proposes that, if the simplified SPD charge were introduced, a price for non-supply should apply that reflected the incidence of non-supply in the absence of the investment. This would mean that the price would reflect the LRMC of the alternative that would have been built in the absence of the transmission investment.

**Figure 14: Effect of price for non-supply in Pole 2 counterfactual on charge allocation under the SPD method using daily capping (left) and monthly capping (right)**




Source: Electricity Authority

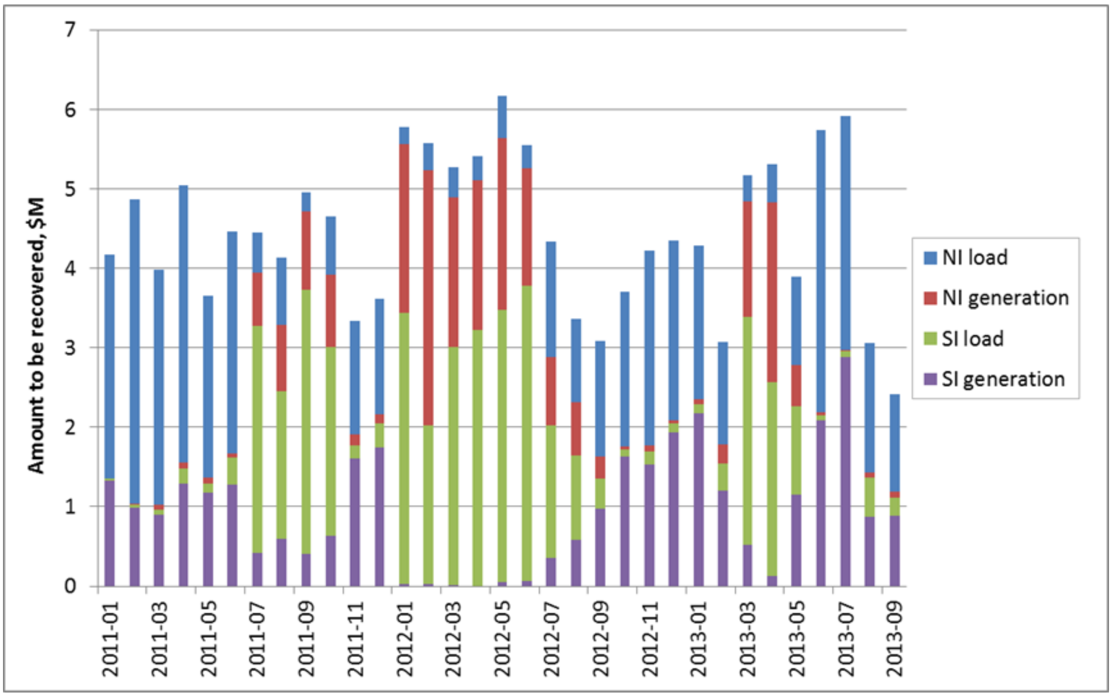
***Period used for calculation of the SPD charge***

7.80 Some submitters had significant concerns that the SPD approach would result in volatile charges. This was a result of the combination of volatile spot market prices and the effect of assumptions used in the SPD method, in particular the price of $3000/MWh for non-supply in the counterfactual.

7.81 The volatility of the SPD charge for Pole 3 calculated half hourly and charged on a monthly basis using gross benefit and daily capping is shown in Figure 15 below for the period January 2011 to September 2013[48]. It shows that both the amount recovered and the incidence of charges is highly volatile from month to month.

[48] In this sub-section, a longer period is used than in other sections as the four-month period was insufficient to demonstrate volatility over a longer period and to demonstrate how calculation using a rolling average would reduce volatility of the charge.

**Figure 15: Incidence of SPD charges for Pole 3 calculated half hourly and charged monthly**




Source: Electricity Authority

7.82 Some submitters were concerned that such volatility would be difficult to manage. This was because they considered there was a lack of a natural counter-party to offer a hedge for this volatility, except Transpower. Further, some submitters considered the volatility did not necessarily reflect the volatility in the wholesale electricity market.

7.83 The Authority has examined the correlation between wholesale prices and the SPD charge proposal in the October 2012 issues paper for a selection of locations over the period July-October 2012 inclusive. The locations were Christchurch load, Auckland load, lower Waitaki generation, and Waikato generation. The results were as follows:

(a) for Christchurch load, there is a positive 99% correlation between mean SPD charging rate and mean spot price - i.e. when spot prices (and hence purchaser costs) are highest, SPD charges are also highest. (The SPD charge tends to add to the spot price volatility faced by the purchaser.)

(b) for Auckland load, the correlation is just 13%

(c) for generation on the lower Waitaki, there is a negative 98% correlation - i.e. when spot prices (and hence generator revenue) are highest, SPD charges are lowest. (The SPD charge tends to add to the spot price volatility faced by the generator.)

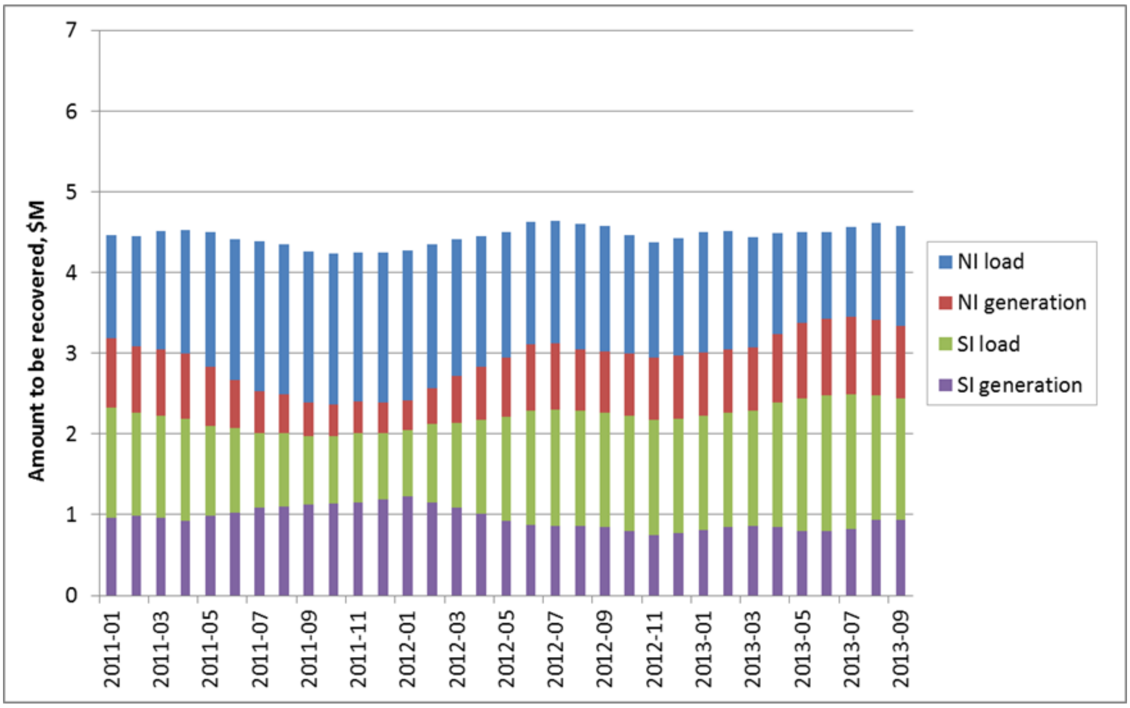
(d) for generation on the Waikato, there is a positive 97% correlation - i.e. when spot prices (and hence generator revenue) are highest, SPD charges are highest. (The SPD charge tends to damp the spot price volatility faced by the generator.)

7.84 This confirms that the volatility of the SPD charge proposed in the October 2012 issues paper does not necessarily correlate with wholesale market price volatility.

7.85 The Authority has therefore simulated the SPD charge using a two-year rolling average to investigate the extent that a rolling average would result in lower monthly volatility. The results of this are shown in Figure 16 for the period January 2011 to September 2013.

7.86 Figure 16 shows that the use of a 2-year rolling average for calculation of the SPD charge would reduce the volatility of the monthly charge considerably, both in terms of incidence and revenue recovered. However, the calculation of the charge over this particular period may mask the true long-term volatility.

**Figure 16: Incidence of SPD charges for Pole 3 using 2-year rolling average**




Source: Electricity Authority

7.87 The Authority considers that calculating the SPD charge using a rolling average may be desirable if it would make the transition to an SPD-based charge easier. Further, a rolling average would reflect the preferences of a number of submitters. Regarding the period for the rolling average, a longer period such as 3 years may be preferable as this would lower volatility further than two years. This would have the added benefit of reducing the ability of parties to inefficiently alter their behaviour to avoid the charge.

### *Charging period*

7.88 Some submitters preferred an annual charging period rather than a monthly charging period. This was to reflect the fact that retail prices in particular are often set on an annual basis rather than a monthly basis.

7.89 Other submitters considered that an even longer charging period would be preferable as this would limit the ability and incentive for parties to alter their behaviour to avoid the charge.

7.90 While monthly charging would reflect monthly settlement of the wholesale market, the Authority is open to considering a longer charging period, such as a year, if this is preferable from a practical point of view. A longer charging period is likely to reduce costs by avoiding the need to either re-set retail charges more frequently or avoiding over-charging of retail customers to hedge against any remaining charge volatility. The Authority notes that improved competition should lower the risk of this occurring. A longer charging period would not undermine the price signal from the SPD charge. However, a longer charging period may mean the change in the level of charges between periods may be more abrupt, although this is potentially also an issue under the current charging arrangements.

### *Charging on net versus gross injection*

7.91 The SPD charge proposed in the October 2012 issues paper took into account the benefit generators received from an investment on the basis of their injection into the grid. While this may be appropriate for grid connected generation, some submitters were concerned that this would overstate the benefit distributed generation received from an investment. These parties considered that, to the extent that distributed generators benefited from the grid, benefits only arose when their generation resulted in a net injection at the node.

7.92 In this regard, it is important to note that the grid enables the operation of the wholesale market. Distributed generators therefore benefit from the grid to the extent the wholesale market provides both an option for sale of any generation not sold by local load and a reference for establishing the price for their generation.

7.93 However, in terms of quantity, it could be argued that the grid mainly influences the capacity a distributed generator is able to dispatch when it is injecting into the grid. The SPD method calculates the benefit a generator receives from a transmission investment based on how the investment influences the price the generator receives and the quantity dispatched. It could be argued therefore that calculating distributed generators’ benefit based on gross injection, if this argument is accepted, overstates distributed generators’ benefit from a transmission investment. Calculating distributed generators' generation on the basis of net injection may therefore be more appropriate, on the basis that it more closely reflects actual benefit.

7.94 The Authority therefore could calculate SPD charges for distributed generation based on net injection rather than gross injection. However, calculating SPD charges for distributed generation in this way may provide incentives for a generator to embed in a distributor's network rather than connect to the grid. Calculating SPD charges in this way would also incentivise generation to locate closer to load.

7.95 Related to the issue of treatment of distributed generation, some major industrial consumers were concerned that the SPD charge proposal would require them to pay SPD charges for grid-connected generation that supplied their plant even though this generation received little benefit from the grid. Some of these parties noted transmission assets could be reconfigured so their grid-connected generation would appear to SPD as embedded generation, thereby reducing their SPD charges. These parties noted that their current RCPD charges are levied at a substation level even though their load and generation may be at separate nodes.

7.96 It is important to ensure that the charge is designed so that it does not promote inefficient behaviour by parties seeking to avoid charges. SPD charges could be applied at a substation level to address this issue. Alternatively the prudent discount policy could address this issue by providing a discount in situations where parties could undertake an investment to avoid transmission charges, even though from an electricity sector perspective this would be inefficient. If the Authority calculated SPD charges on a substation basis to minimise incentives for inefficient avoidance of the charge, this approach should only apply at locations where grid-connected generation has been installed to supply a specific load at a separate node but at the same location. The Authority would welcome comment on whether calculation of SPD charges for embedded generation on a gross or net injection basis would best promote efficiency. The Authority would also welcome comments on whether levying SPD charges for major load on a substation basis would best promote efficiency or whether the prudent policy discount would better deal with these issues. The Authority will examine this issue further prior to preparation of the second issues paper.

***Applying a minimum threshold for generation subject to the SPD charge***

7.97 Some submitters, mainly generators with small scale generation, were concerned that the complexity of the SPD charge imposed excessive compliance costs on smaller parties who did not have the scale to deal with the level of complexity.[49] They therefore suggested a minimum threshold for generation subject to the SPD charge of 10MW.

7.98 Complexity of the SPD charge is not an issue that is necessarily specific to generators or small generators. Calculation of the SPD charge relies on wholesale market outcomes so parties operating in the wholesale market should

[49] e.g. Pioneer Generation.

have the capability to manage any complexity associated with the SPD charge. However, some small generators may not deal much with the wholesale market at present. For example, embedded generators are not required to provide information regarding the intended output of any generating station that has less than 10 MW of capacity (clause 8.25 of the Code). A generator is not required to submit an offer for a generating station that is 10MW or smaller (clause 13.25 of the Code).

7.99 From both a practicality and efficiency perspective it is likely to make sense to set a minimum threshold for generation subject to the SPD charge. For example, at the extreme, the transactions costs of applying the SPD charge to each photovoltaic cell would be excessive. However, a minimum generation threshold for the SPD charge would inefficiently incentivise investment in generation below the threshold in order to avoid the charge.

7.100 Some submitters considered a minimum threshold of 10MW for application of the SPD charge was appropriate, on the basis that this was consistent with the clause 8.25(5) threshold.[50]

7.101 The Authority proposes that the minimum threshold should be 10MW by scheme (a generation investment at a single location that involves one or more generators eg a windfarm, hydro scheme etc). This is because some large and very large schemes may have individual generators less than 10MW, e.g. some wind farms, and it would be inefficient to exempt such schemes from the SPD charge.

7.102 A threshold of 10MW by scheme should provide an appropriate balance between:

(a) ensuring broad coverage of the SPD charge

(b) minimising incentives for avoidance of the charge through sub-optimal generator capacity

(c) ensuring the parties paying the charges have the necessary scale to cope with the complexity of the charge to the extent this is an issue

(d) keeping transactions costs to a reasonable level.

***Application of the simplified SPD method to instantaneous reserve charges***

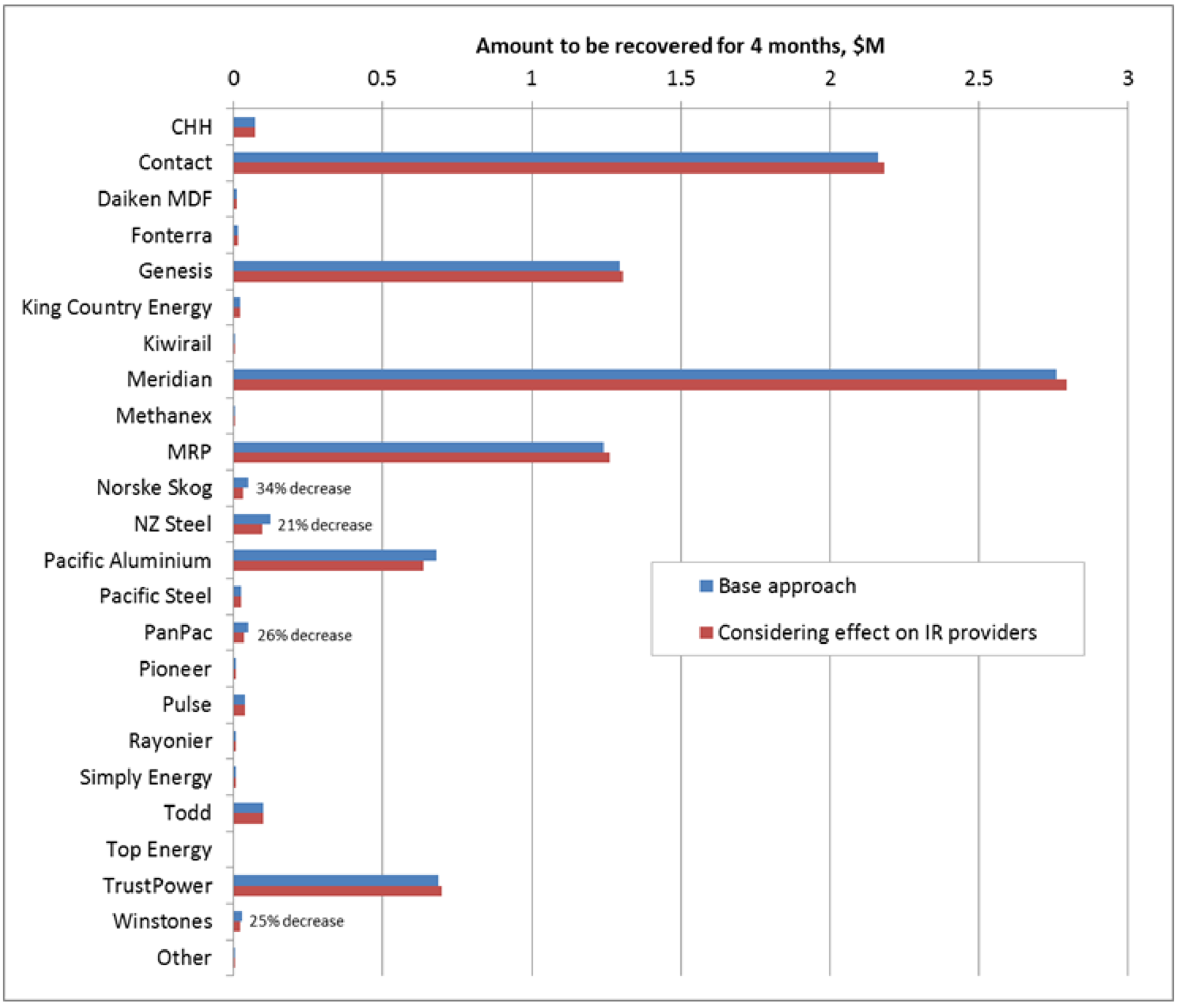
7.103 The simplified SPD method assesses benefits to generators and spot market purchasers in terms of the extent to which a transmission investment increases their producer and consumer surplus respectively in relation to the energy market. As a refinement, the method could also consider benefits to parties that provide instantaneous reserve (IR) according to the extent to which transmission investments increase producer surplus in terms of participation in the IR market. The IR producer surplus would be the difference between IR revenues and IR

[50] e.g. Pioneer Generation, Clearwater Hydro.

provision costs, where IR provision costs could be estimated as the sum over IR tranches of (dispatched quantity multiplied by offer price). HVDC investments can affect the IR producer surplus by altering the IR requirements in each island.

7.104 This refinement to the simplified SPD method has been implemented and tested on a single investment – HVDC Pole 3. This is set out in Figure 17. It could also be applied to HVDC Pole 2.

**Figure 17: SPD charges for Pole 3 for IR providers from not taking into account (base) and taking into account change in producer surplus of IR providers (gross benefit, daily capping)**




Source: Electricity Authority

7.105 The overall effect on simulated transmission charges is modest. However, there is a significant impact (in percentage terms) on the charges on direct connect consumers that provide interruptible load (IL). For these consumers, the benefit of Pole 3 in terms of reducing energy costs is partially offset by the disbenefit of Pole 3 in terms of reducing IL prices.

7.106 Given this would result in a more accurate calculation of the benefits resulting from transmission investments the Authority proposes that benefits to IR providers should be included in calculation of the SPD charge.

7.107 Note that it is not proposed to consider benefits to parties that pay for IR, since these payments take place outside the spot market.

***Preliminary conclusion on parameters for simplified SPD charge***

7.108 Based on the analysis and modelling presented in this section, the Authority proposes that the simplified SPD charge would have the following parameters:

(a) the simplified SPD charge would apply to:

(i) Pole 2

(ii) investments, including replacement assets, added to Transpower's regulatory asset base after 28 May 2004 but before 10 October 2012 with a cost greater than $50m

(iii) investments, including replacement assets, added to Transpower's regulatory asset base from 10 October 2012 with a cost greater than $20m

(b) the charge should be calculated in relation to one period and charged for that period during the following period, ie the charge would be calculated ex post and applied ex ante (see paragraph 7.14 for a description of how this would work)

(c) the charge would be calculated on the basis of gross benefits from transmission investments for which the charge is being calculated, i.e. disbenefits would be ignored

(d) the amount that could be recovered under the charge from beneficiaries for any single day would be capped to no more than the daily share of annualised costs of the investment

(e) where demand is subject to dispatchable demand, dispatchable demand bids would be used for calculation of the SPD charge, provided dispatchable demand is dispatched. For other demand not subject to dispatchable demand, the SPD charge would be calculated using an demand elasticity based on empirical estimation

(f) the price for non-supply that should apply should reflect the incidence of non-supply in the absence of the investment. Of the 10 investments modelled in this paper, this would mean a price for non-supply of $3000/MWh, except for Pole 2, which would have a price for non-supply of $1000/MWh

(g) the SPD charge would be calculated using a three-year rolling average, though this would be subject to review

(h) the charging period would be one year (which would involve lower transactions costs than monthly charging)

(i) SPD charges for distributed generation would be calculated on the basis of net injection to the grid

(j) SPD charges would be calculated at substation level at locations where grid-connected generation has been installed to supply a specific load at a separate node at the same location

(k) the minimum threshold for the SPD charge would be 10MW by scheme

(l) benefits to IR providers should be included in calculation of the SPD charge.

**Assessment of simplified SPD charge**

7.109 In the October 2012 issues paper each option was assessed for whether it was lawful, practicable, was likely to provide net benefits, and had the potential to recover costs currently recovered under the interconnection and HVDC charges. This paper assesses each of the options on the same basis.

7.110 The assessment of the costs and benefits of the options is qualitative rather than quantitative. A quantitative cost-benefit analysis will be conducted for the Authority's preferred option in the second issues paper, along with one or more alternative options. This would use the framework set out in the CBA working paper but take into account submissions on that paper.

***Lawfulness of using the simplified SPD method to apply beneficiaries-pay charges***

7.111 The simplified SPD charge is lawful.

***Practicability of using the SPD method to adopt beneficiaries-pay charges***

7.112 The proposal uses an existing model (SPD or vSPD) to calculate charges and identify parties subject to the charge, and so it should be practicable to implement. The Authority's modelling of the simplified SPD charge demonstrates that it is practicable.

7.113 If a party other than Transpower was allocated the role of applying the SPD method to be used as an input to calculating the charge, a method would be required to calculate security constraints consistent with the approach used by Transpower (who use the simultaneous feasibility test (SFT) model).

7.114 The main practical issue is the time and computational resources required to undertake separate SPD or vSPD solves for each asset for each half hour period. As such, the method is probably most practicably applied to a subset of transmission assets. If the computational resources were constrained, a charge based on a sample of a large number of trading periods over a long period (e.g. a year) could be used.

***Assessment of costs and benefits of the simplified SPD charge***

7.115 The benefits of the simplified SPD charge are it would promote:

(a) efficient transmission investment by increasing the transparency of the benefit parties obtain from transmission assets, and by placing stronger incentives on parties identified as beneficiaries to participate in the investment decision-making and approval process

(b) efficient investment by generation and load, as allocating charges to beneficiaries means they would face some of the transmission cost implications of their investment decisions

(c) allocative efficiency as charging beneficiaries should reduce deadweight loss, as a greater proportion of the costs of transmission assets that are currently paid for under the interconnection charge by non-beneficiaries would be paid for by beneficiaries. The reduction in deadweight loss would depend on the extent to which the charge reflects aggregate benefit

(d) productive efficiency as parties would not have incentives to limit their production to limit their charge liability as they may do under the status quo

(e) durability as charges would be calculated using an objective method that is flexible to changes in use of the grid and based on economic fundamentals.

7.116 The likely costs of the proposal are:

(a) implementation costs for both Transpower and participants, including set-up costs involved in implementing the option, including computer equipment, any licence costs, development and testing

(b) operational costs to Transpower and the party applying the SPD method (if this was not Transpower), including the on-going costs of applying the option to estimate the benefits from transmission assets

(c) costs to participants to verify their SPD charge

(d) inefficient investment to the extent that charging based on benefit does not reflect LRMC

(e) allocative and productive inefficiency to the extent that charging based on benefit does not affect LRMC

(f) incentives for inefficient avoidance of the charge. This would need to be addressed through the design of the charge or through other mechanisms, such as the prudent discount policy.

7.117 A quantitative CBA is required to determine whether the simplified SPD method results in net benefits. However, through better promoting efficient investment than the status quo, the Authority's preliminary view is that the simplified SPD method would result in net benefits over time relative to the status quo.

***Potential to recover HVDC and interconnection costs***

7.118 The simplified SPD charge may under-recover costs in the years immediately following a large transmission investment. Any costs not recovered through the SPD charge (and through LCE and the kvar charge, if these proposals are confirmed) would be recovered through a residual charge. Possible designs for a residual charge are discussed in the residual charge working paper.

**Parties subject to simplified SPD charge**

7.119 The Authority proposed that generators, retailers and direct connect consumers would be subject to the SPD charge in the October 2012 issues paper. These parties benefit from transmission to the extent it enables them to participate in the wholesale electricity market and affects the price and quantity of the electricity they generate or purchase as applicable. These parties are also familiar with the wholesale electricity market and this should ensure that they can understand the SPD method.

7.120 Some submitters questioned whether retailers should be subject to the SPD charge. The Authority proposed that retailers, rather than distributors, should be subject to the SPD charge because:

(a) of retailers' greater familiarity with the wholesale electricity market, which would mean they would be better placed to deal with the SPD method and SPD charge

(b) unlike many distributors, retailers do not have a mandated ability to pass through transmission charges, so they would have greater incentive to scrutinise transmission costs if they were subject to SPD charges than distributors.

7.121 In deciding whether distributors or retailers should be subject to the SPD charge, the key question is which would be the most efficient "agent" for end consumers benefiting from transmission investment.

7.122 The advantages of making distributors subject to the SPD charge are that:

(a) they are already, and will continue to be, transmission customers by virtue of their connection to the transmission network

(b) the distributor, being a local monopoly has a continuous relationship with end consumers, whereas a consumer may switch retailers

(c) their businesses are lower risk, implying lower credit risk, lower credit costs and therefore lower costs to end consumers

(d) they are likely to be more familiar with the regulatory regime applying to transmission and to transmission technology and operation so may be better placed to provide input on consumers' behalf into transmission investment proposals

(e) they are likely to directly pass through transmission charges to large consumers connected to the network, which would preserve price signals to these customers.

7.123 The disadvantages of making distributors subject to the SPD charge are that:

(a) many distributors have a mandated ability to pass through transmission charges so lack incentives to scrutinise transmission charges

(b) they are less likely to be familiar with the wholesale market so are not well placed to deal with the SPD method and SPD charges

(c) it would involve higher transactions costs as most would pass charges on to retailers for mass market consumers anyway.

7.124 The advantages of making retailers subject to the SPD charge are that:

(a) they are familiar with the wholesale market so are likely to be better placed than distributors to deal with the SPD method and charge

(b) they have no mandated ability to pass through transmission charges so may have greater incentives to scrutinise charges. Against this, though all retailers at a node would face the same charge so this incentive may be weak. On the other hand, experience from other industries, e.g. airlines and landing charges, suggests this does not undermine incentives to scrutinise charges. However, airlines face incentives such as inter-modal competition, which may be weaker in the case of electricity. This means there is unlikely to be a potential direct benefit to retailers from lower charges

(c) it would involve lower transactions costs as distributors would not be involved in these charges.

7.125 The disadvantages of making retailers subject to the SPD charge are that:

(a) they are not transmission customers at present, except to the extent they are generators

(b) their businesses are less stable implying greater credit risk, higher credit costs and therefore imposing the SPD charge on retailers would be likely to result in higher costs to end consumers

(c) except to the extent they are generators, they are likely to be less familiar with transmission technology and operation, and potentially the transmission regulatory regime, and may therefore not be well place to scrutinise transmission costs

(d) they are likely to bundle transmission charges with other costs in their retailer offerings so price signals may not be preserved. However, bundling transmission charges has the potential to make them vulnerable to competition from other retailers who price more efficiently.

7.126 The difference in advantages and disadvantages between making retailers versus distributors subject to the SPD charge are not large. On balance, the Authority considers that there are likely to be greater net benefits with making retailers subject to the SPD charge rather than distributors through their likely greater familiarity with wholesale market and greater incentive to scrutinise transmission costs because of the lack of a mandated ability to pass through transmission charges. Quantitative cost-benefit analysis would be needed to confirm that this is the case. This could take into account the different elasticities in demand for transmission services between retailers versus distributors.

7.127 The Authority continues to consider that generators, retailers and direct connect consumers should also be subject to the SPD charge.

**Conclusion on application of simplified SPD charge**

7.128 The Authority considers that the simplified SPD charge would better promote the Authority's statutory objective of competition in, reliable supply by, and efficient operation for the long-term benefit of consumers than the status quo. The Authority considers that the proposed modifications to the SPD charge address many of the key issues identified by submitters in relation to the SPD charge. The Authority therefore considers that the simplified SPD charge should be considered as part of an option for a revised TPM.

# 8 Option 2(a) - GIT-plus-SPD

### Overview of option

8.1 This is the first of two approaches for an option seeking to respond to the suggestions in submissions that, to promote efficient investment, the charging approach needs to align with the Commerce Commission's transmission investment approvals process. The concept of this option is that the costs of a transmission investment approved on the basis of a reduction in expected unserved energy, or approved to meet the N–1 safety net, would be recovered from the parties receiving the reliability benefits from that investment.

### Investments subject to GIT-plus-SPD charges

8.2 The Authority proposes that if the GIT-plus-SPD option were applied, the same criteria would be used for determining the assets subject to GIT-plus-SPD option as for the simplified SPD charge.[51] In particular, the Authority proposes that the GIT-plus-SPD option would apply to:

(a) Pole 2

(b) investments, including replacement assets, added to Transpower's regulatory asset base after 28 May 2004 but before 10 October 2012 with a cost greater than $50m

(c) investments, including replacement assets, added to Transpower's regulatory asset base from 10 October 2012 with a cost greater than $20m.

8.3 Of those investments, a GIT-based charge would be applied to recover the costs of an investment approved primarily on the basis that it:

(a) is necessary to meet the N – 1 limb of the grid reliability standards;[52] or

(b) otherwise reduces expected unserved energy.

8.4 It is anticipated that the Authority would determine whether a GIT-based charge would apply in relation to a particular asset.

8.5 The above criteria fit with both the investment test specified for major capex projects approved under the Commerce Commission's Capital Expenditure Input Methodology (Capex IM), and investments approved by the Electricity Commission under schedule F4 of Part F of the Electricity Governance Rules (Rules).

8.6 The GIT-based charge would not apply to minor or base capex proposals.

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[51] See paragraphs 7.4-7.11 for an explanation of the reasons for these proposed thresholds.

[52] The term "necessary to meet" was considered, in the context of clause 4.1 of the grid investment test, by the Court of Appeal in *Major Electricity Users' Group v Electricity Commission and Transpower New Zealand Limited* [2008] NZCA 536, [66] to [82]. The Court did not accept that "necessary to meet the N-1 standard meant "necessary to meet the N-1 standard and no more", but found that a project could be "necessary to meet" the N-1 standard even if it did more than meet that standard.

8.7 The cost of investments not subject to a GIT-based charge would be recovered through a simplified SPD charge on the same basis as under the simplified SPD option. As with the simplified SPD option, the SPD charge may not fully recover the costs of these assets. Another charge would be required to recover residual costs.

8.8 The Authority considers that, under the above criteria, the following investments would be subject to the GIT-based charge (assuming the investment has been completed):

(a) NIGU

(b) NAaN

(c) UNI reactive

(d) Otahuhu GIS

(e) USI reactive

(f) LSI reliability.

8.9 The following investments would be subject to the simplified SPD charge, assuming the investment has been completed:

(a) Pole 2

(b) Pole 3

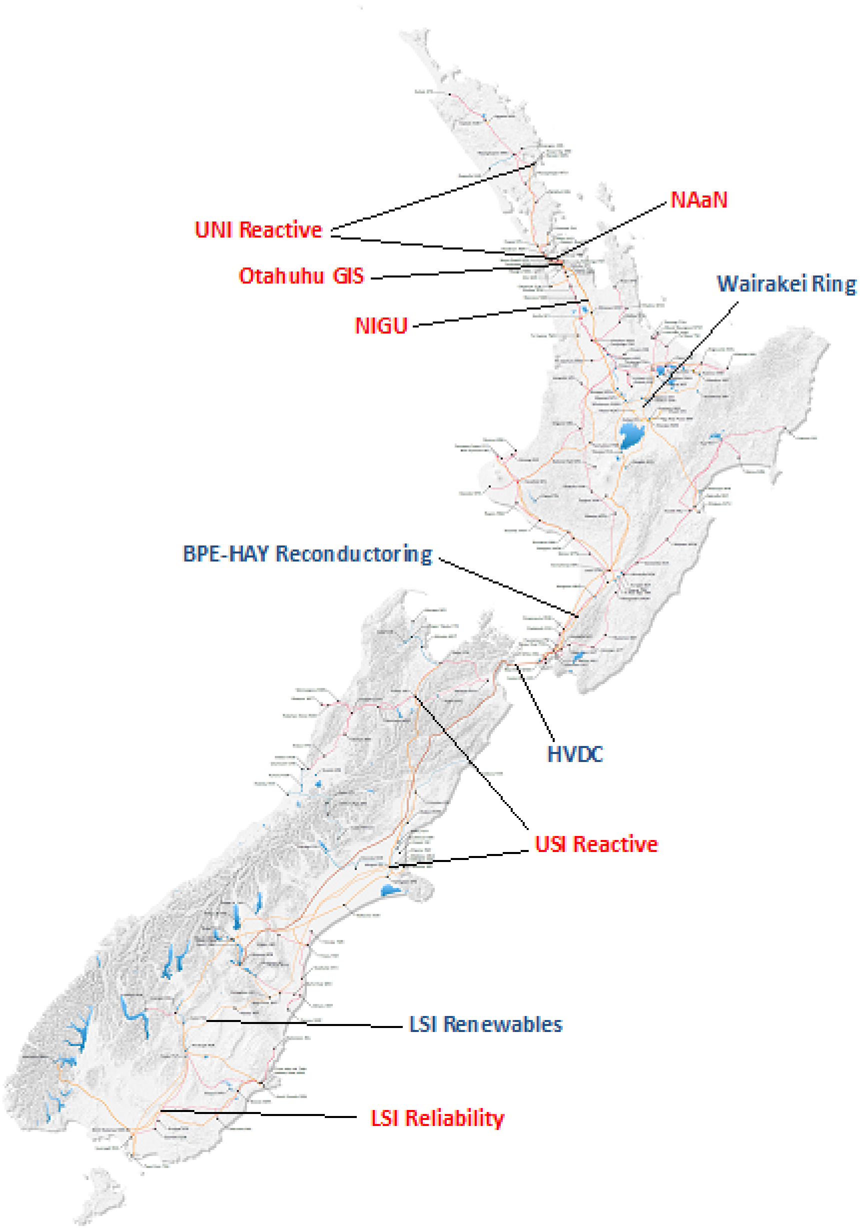
(c) Wairakei Ring

(d) LSI renewables

(e) BPE-HAY.

8.10 These investments are shown in Figure 18.

**Figure 18: Assets subject to GIT-plus-SPD option**




Source: Electricity Authority

Notes:
1. Red lettering shows assets subject to the GIT-based charge
2. Blue lettering shows assets subject to the simplified SPD charge

8.11 The GIT-based charge would be allocated to all load in an "area of benefit". The area of benefit would be the GXPs that benefit from the investment.

8.12 The Authority proposes that for the purposes of applying the GIT-based charge, in identifying the area benefiting from an investment, only reliability benefits stemming from the main function of the investment would be considered.

Reliability benefits stemming from secondary functions of the investment and non-reliability benefits[53] would not considered. The rationale for this is that the charge would be applied to those who receive the benefit that was the principal justification for the investment. This is because the intention with the GIT-based charge is to ensure that incentives to promote an investment are aligned with willingness to pay for it. This should help promote efficient investment.

8.13 For example, the primary justification for the NIGU project was improved reliability in the upper North Island region; if the project did not promote this objective it would not have proceeded. The NIGU project was also justified by Transpower on the basis that it would reduce the risk of cascade failure affecting the Waikato and Bay of Plenty.[54] However, the project would not have proceeded for that reason alone, as the benefits of reducing the risk of cascade failure were insufficient by themselves to justify the investment. Accordingly, for the NIGU project the GIT-based charge would only be applied to loads in the upper half of the North Island.

8.14 For each eligible investment, the full revenue requirement would be recovered from load in the 'area of benefit' in each year. This differs from the simplified SPD charge, which would recover only part of the revenue requirement in each year – with the remainder being recovered through a residual charge.

8.15 The allocation of the charge would be in proportion to energy consumed in the previous year's measurement period (or, in the case of industrial consumers that have their charges calculated at a substation level[55], net energy consumed).

8.16 The fact that the parties subject to the charge are determined on an ex ante basis and the fact that the revenue from the charge is fixed each year means that the GIT-based charge would have features closer to a long term contract, such as for a shared connection asset, than the SPD charge. However, the actual amount that a party would pay in each year would vary depending on its demand (or net demand in the case of industrial consumers whose charges would be calculated at a substation level).

8.17 The GIT-based charge can be applied to investments undertaken to improve reliability that rarely or never have an impact on the wholesale market, as calculating the benefit from the investment does not rely on wholesale market outcomes. For this reason, it can be applied to investments that the SPD charge either cannot be applied to or, if the SPD charge were applied, would result in

[53] Such as fuel cost benefits, demand-side management benefits, cost change benefits, deferral benefits, capital cost benefits, O&M benefits, ancillary services benefits, loss benefits, statutory compliance benefits, real option benefits, competition benefits, terminal benefits and terminal costs, or non-quantifiable material market costs and benefits.

[54] North Island Grid Upgrade Project, amended proposal, attachment A, page 15 available from http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2005-gup/

[55] See paragraphs 7.88 - 7.90.

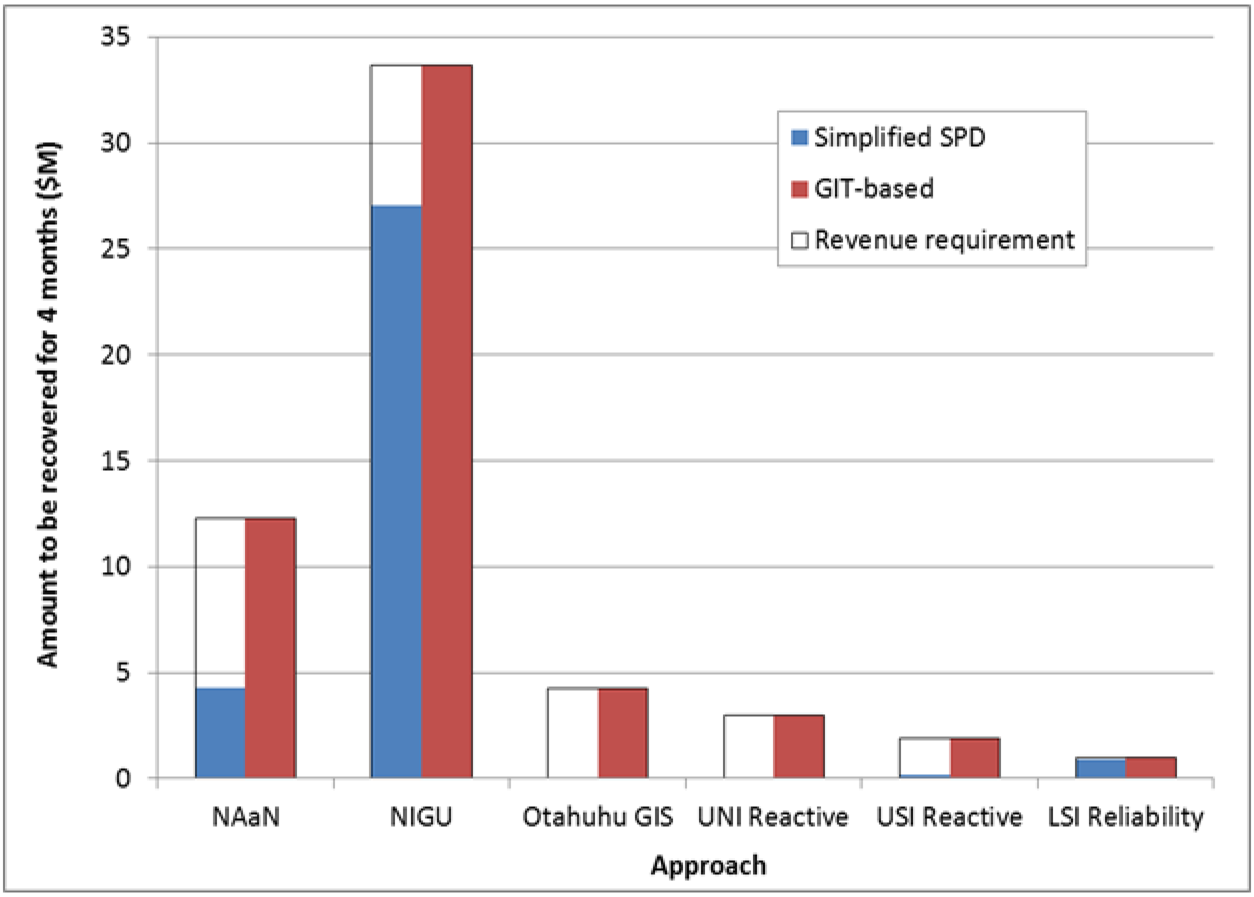
very little revenue. Examples include the Otahuhu Substation Diversity Proposal[56] (Otahuhu GIS) and the Upper North Island reactive support project.[57]

### Modelling results for GIT-plus-SPD option

8.18 The GIT-plus-SPD option was modelled on the same basis as for the simplified SPD method using data from the 4 month period July-October 2012 inclusive.

8.19 The revenue recovered by the GIT-based charge for the eligible investments relative to the revenue requirement is shown in Figure 19. The revenue recovered under the simplified SPD charge for these investments using gross benefit and daily capping is also shown for comparison.

**Figure 19: Revenue recovered for investments under GIT based and Simplified SPD charges for 4 months**




Source: Electricity Authority

8.20 Figure 19 shows that the GIT-based charge fully recovers the costs of investments to which that charge would currently apply. This means that the GIT-

56 Details available from http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2005-gup/otahuhu-substation-diversity-proposal-history/

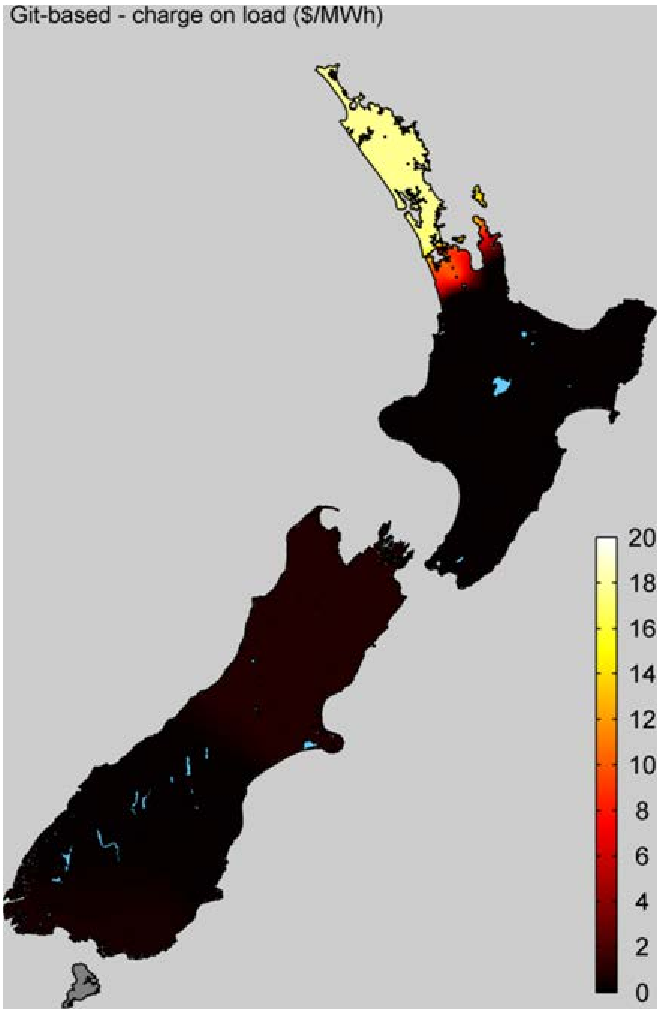
57 Details available from http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/upper-north-island-dynamic-reactive-support-investment-proposal-archive/

based charge would imply full beneficiaries-pay for these investments. This is, of course, a logical consequence of the fact that the charge is fully applied to the parties that receive the reliability benefits of the investment.

8.21 In comparison, the simplified SPD charge would not fully recover the costs of these investments during this period – at least when it is calculated using gross benefits and a daily cap.In the case of the Otahuhu GIS and UNI reactive investments no revenue is recovered under the simplified SPD charge, while only a small proportion of the revenue requirement (10%) is recovered in relation to the USI reactive investment. The reason for this is that the SPD method either does not identify benefits for these investments or only identifies benefits very infrequently. This does not mean there are no benefits from these investments; rather the SPD method only identifies benefits that flow through to the wholesale market. The GIT-based charge, by comparison, fully takes into account reliability benefits in setting the charge

8.22 The regional incidence of these GIT-based charges is shown in Figure 20. Figure 20 only shows the incidence of the GIT-based charge for load as generation is not subject to the GIT-based charge.

**Figure 20: Incidence of GIT-based charges for eligible investments for 4 months**



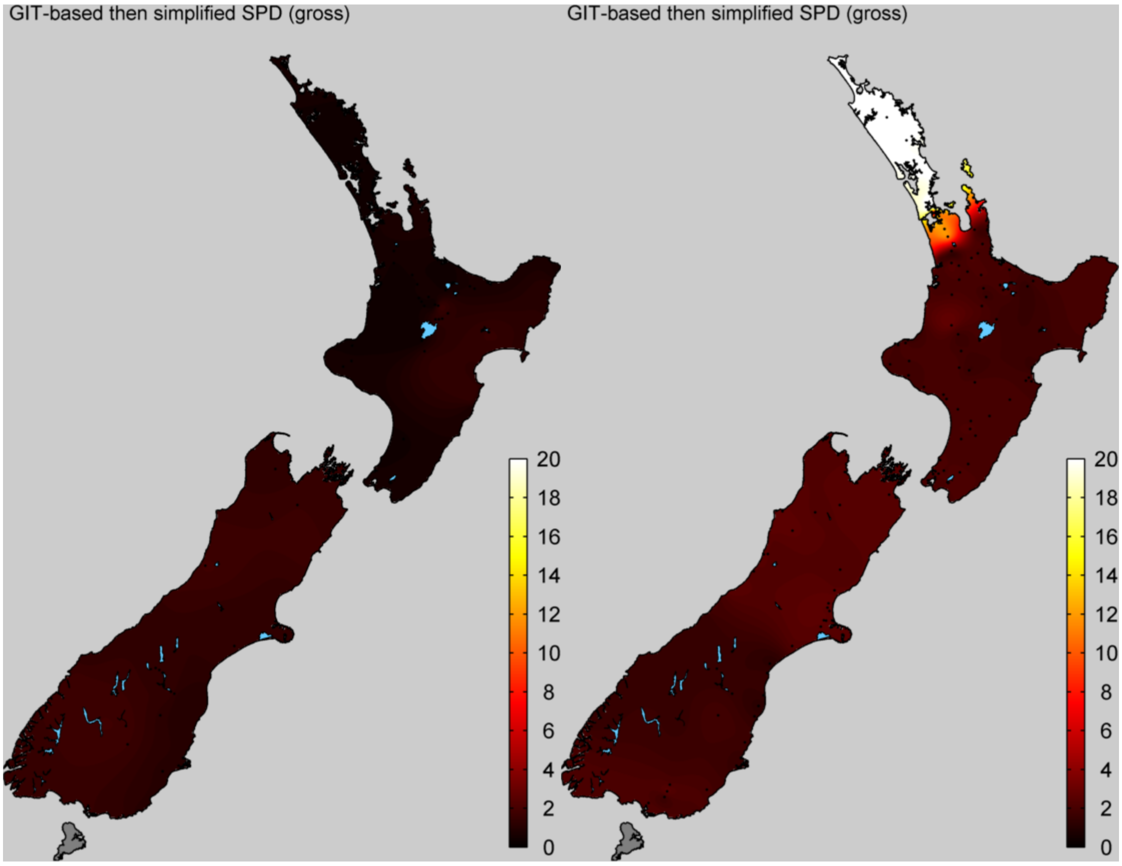

Source: Electricity Authority

8.23 Figure 20 shows that the GIT-based charge primarily recovers the costs of the relevant investments from upper North Island load. North Island loads are the primary beneficiaries of the four largest eligible investments by cost – NIGU, NAaN, Otahuhu GIS and UNI reactive support. A small amount of revenue is recovered from the upper South Island for the USI reactive support project and from the Lower South Island for the LSI reliability investment. The central and lower North Island are not subject to GIT-based charges as there were no eligible investments that provided a primary benefit to these regions.

8.24 The overall incidence of charges under the GIT-plus-SPD option – the combination of GIT-based charges for reliability investments and the simplified

SPD charge (applied using daily capping and gross benefit[58]) for investments undertaken to reduce costs of generation – is shown in Figure 21.

**Figure 21: Incidence of charges under GIT-plus-SPD option for generation (left) and load (right) for 4 months**




Source: Electricity Authority

8.25 Figure 21 shows the incidence for charges under the GIT-plus-SPD option for generation (left) and load (right). In the case of load the incidence is a combination of the GIT-based charge and the simplified SPD charge. Generation, however, is only subject to the simplified SPD charge.

8.26 Figure 21 shows that under the GIT-plus-SPD option, upper North Island load and, in particular, North Auckland and Northland, would face significantly higher charges (around $20/MWh during this period) than load in other areas and generation. Most other load faces charges between about $3 and $10/MWh.

8.27 Generation would face lower charges than load under the GIT-plus-SPD option. South Island generation and eastern central North Island generation would face higher (simplified SPD) charges than other areas. This is because generators in these areas are the primary beneficiaries of the largest investments by cost

58 The Authority notes that a simplified SPD charge calculated using the NBR approach would be more theoretically consistent with the GIT-based charge, since both charges would effectively be charged on the basis of net rather than gross benefit.

undertaken to reduce costs of generation – Pole 2 and Pole 3 in the case of South Island generation and Wairakei Ring in the case of eastern central North Island generation.

8.28 Although the pattern of incidence is similar to the simplified SPD charge (see Figure 3), the distribution of incidence is more extreme under the GIT-plus-SPD option. In particular, the charges for North Auckland and Northland load are roughly double under the GIT-plus-SPD option compared to what they are under the simplified SPD charge. Charges to all other parties are generally lower under the GIT-plus-SPD option, as upper North Island load would bear all of the costs of the NIGU and NAaN projects. The costs of these projects are spread more broadly under the simplified SPD charge.

### Assessment of GIT-plus-SPD option

#### *Lawfulness of using GIT-plus-SPD option to apply beneficiaries-pay charges*

8.29 The GIT-plus-SPD approach of applying the GIT-based charge to recover the reliability-related costs of investments is lawful.

#### *Practicability of using GIT-plus-SPD option to apply beneficiaries-pay charges*

8.30 The GIT-plus-SPD option has the same practicability issues as the simplified SPD charge in relation to cost-recovery of those investments that would be subject to the simplified SPD charge.

8.31 The main practicability issues in relation to the GIT based charge are:

(a) identifying the area receiving reliability benefits from eligible investments. Where the investment test in the Capex IM includes an estimate of involuntary demand curtailment borne by end users of electricity this is calculated by multiplying the expected quantity of curtailed demand by the value of expected unserved energy.[59] The Authority could discuss with the Commerce Commission making identification of the area of benefit for relevant investments an explicit requirement of the investment application, or the Code could be amended to give the Authority the power to determine the area of benefit

(b) identifying the nodes in the area receiving reliability benefits at which the GIT-based charge would be applied. Provided the area receiving reliability benefits from an investment is clear, this should be straightforward

(c) allocating GIT-based charges to nodes and load at nodes. This should be straightforward as in both cases the allocation is based on demand in the measurement period for the previous year.

[59] Clause D7(5), Transpower Capital Expenditure Input Methodology Determination 2012, Schedule D.

***Assessment of costs and benefits of GIT-plus-SPD option***

8.32 The benefits of the GIT-plus-SPD option are:

(a) it would provide the same efficiency benefits as the simplified SPD charge in relation to relevant investments that would be subject to the SPD charge – that is, investments undertaken to lower the costs of generation

(b) the GIT-based charge would:

(i) promote efficient investment in relation to investments undertaken to provide reliability benefits as the GIT-based charge would align incentives to promote transmission investments to improve reliability with payment for those investments. This would provide strong incentives for expected beneficiaries to participate in the investment decision-making and approval process and ensure all relevant information is considered in the decision on whether to undertake the investment

(ii) promote efficient investment by load, as allocating charges to beneficiaries of reliability investments means they would face the transmission cost implications of their investment decisions

(iii) promote allocative efficiency as:

- charging beneficiaries should reduce deadweight loss, as a greater proportion of the costs of transmission assets that are currently paid for under the interconnection charge would be paid for by beneficiaries. The reduction in deadweight loss would be larger than under the simplified SPD charge option as no residual charges would apply to relevant reliability investments
- it would promote efficient use of the grid as the only means of avoiding the charge would be to reduce load. This means relative to the simplified SPD charge alone there is a lower risk of inefficient behaviour to avoid the charge.

8.33 The likely costs of GIT-plus-SPD option are:

(a) it would provide the same efficiency costs as the simplified SPD charge in relation to eligible investments that would be subject to the SPD charge – that is, investments undertaken to lower the costs of generation

(b) in relation to the GIT-based charge:

(i) implementation costs for both Transpower and participants, including set-up costs involved in implementing the option

(ii) operational costs to Transpower, which would mainly relate to determining the allocation of the GIT-based charge to particular nodes and load at the node

(iii) costs to participants to verify their GIT-based charge. Participants could obtain assistance from third party providers, which would help limit the costs of this

(iv) inefficient investment to the extent that charging based on benefit does not reflect LRMC. This cost is likely to be lower under the GIT-based charge as, to the extent the investment is justified by the benefit received, the costs of the charge are likely to better reflect LRMC

(v) inefficient investment to the extent that charges do not reflect actual benefit given changes in use of the grid over time, e.g. if the GIT-based charge applied at the Bromley substation in Christchurch the GIT-based charge would not reduce even though demand has reduced substantially at that substation. Similarly, by fixing the GIT-based charge the charge does not reflect the level of benefit immediately following an investment

(vi) allocative and productive inefficiency to the extent that:

- charging based on benefit does not affect LRMC
- the allocation of charges does not reflect benefit over time as a result of changes to the pattern of use of the grid. To address this issue, the GIT-based charge could reset through regulation if there had been a substantial change in circumstances such as through a natural disaster

(vii) incentives for inefficient investment to avoid the charge. This would mainly be an issue in areas subject to significant cost increases as a result of the charge – the upper North Island. While the ability of parties to alter their behaviour to avoid the charge is limited, the high level of the charge in the upper North Island would provide strong incentives on parties paying the charge in this area to disconnect from the grid or remain connected but install inefficient embedded generation. This would need to be addressed through the design of the charge or through other mechanisms, such as the prudent discount policy. However, full allocation of costs to beneficiaries increases the chance that inefficient investments will ultimately be borne by the Transpower shareholder, and therefore socialised more efficiently across the general tax base, rather than just electricity consumers.

8.34 A quantitative CBA is required to determine whether the GIT-plus-SPD option results in net benefits. However, the Authority’s preliminary view is that GIT-plus-SPD option would result in net benefits over time relative to the status quo, because the option would promote efficient investment.

***Potential to recover HVDC and interconnection costs***

8.35 The GIT-based charge would fully recover costs of eligible reliability investments.

8.36 The simplified SPD charge may under-recover costs of non-reliability investments subject to the SPD charge under GIT-plus-SPD option in the years immediately following a large transmission investment. Any costs not recovered through the SPD charge would be recovered through a residual charge. Possible designs for a residual charge are discussed in the residual charge working paper.

**Parties subject to charges under GIT-plus-SPD option**

8.37 The GIT-based charge would apply to load – that is, direct connect consumers and either retailers or distributors.

8.38 As with the simplified SPD charge, the key question in deciding on which of distributors or retailers should be subject to this charge is which would be the more efficient agent. The advantages and disadvantages of applying the GIT-based charge to distributors versus retailers are likely to be the same as for the simplified SPD charge except that no familiarity with the wholesale market is required. For this reason, it may be more efficient to apply the GIT-based charge to distributors rather than retailers. Quantitative cost-benefit analysis would be needed to confirm that this is the case.

8.39 The simplified SPD charge should apply to generators, direct connect consumers, and retailers for the same reason as under the simplified SPD charge option.

**Conclusion on application of GIT-plus-SPD option**

8.40 The Authority considers that the GIT-plus-SPD option would better promote the Authority's statutory objective of promoting competition in, reliable supply by, and efficient operation of the electricity industry for the long term benefit of consumers than maintaining the status quo.

8.41 Because the GIT-based charge enables full recovery of the costs of reliability investments, including some for which full cost recovery is unlikely with the simplified SPD charge, it arguably better achieves beneficiaries-pay than the simplified SPD charge alone. The GIT-based charge could therefore form part of an option for a revised TPM.

8.42 A key issue with the GIT-based charge is that since it is fixed it does not take into account changes in the benefit from transmission investments over time. As a result charges could become in excess of actual benefit over time, which may promote inefficient behaviour, such as disconnection from the grid or inefficient investment in generation. It may therefore be appropriate to schedule regular recalculations of the GIT-based charge, e.g. every 4-5 years, or establish a threshold for when re-calculation is appropriate. However, it should be noted that this issue also applies to connection assets, and connection charges are not subject to periodic regulatory resets.

# 9 Option 2(b) - SPD-plus-GIT option

### Overview of option

9.1 This is the second approach to a GIT-based option. It is the same as the GIT-plus-SPD option but, unlike that option, the simplified SPD charge would first be applied to all eligible investments and then the GIT-based charge would then be applied to recover any costs not recovered by the SPD charge.

9.2 This option seeks to charge according to wholesale benefits when they arise. It would reflect that the recipients of the benefits of an investment may change over time and so beneficiaries-pay charging should seek to reflect this. However, since the SPD method may not fully capture the benefits from transmission investments designed to reduce expected unserved energy, or meet the N–1 safety net, the GIT-based charge would be applied to recover costs not recovered under the SPD charge. The GIT-based charge would apply to parties expected to receive the reliability benefits from an investment that were the main justification for the project.

### Investments subject to GIT-plus-SPD charges

9.3 The Authority proposes that if the SPD-plus-GIT option were applied, the same criteria would be used for determining the assets subject to SPD-plus-GIT option as for the simplified SPD and the GIT-plus-SPD options.[60] In particular, the Authority proposes that the SPD-plus-GIT option would apply to:

(a) Pole 2

(b) investments, including replacement assets, added to Transpower's regulatory asset base after 28 May 2004 but before 10 October 2012 with a cost greater than $50m

(c) investments, including replacement assets, added to Transpower's regulatory asset base from 10 October 2012 with a cost greater than $20m.

9.4 Under this option, the simplified SPD charge would apply to all of these investments.

9.5 The GIT-based charge would then be applied to recover costs not recovered under the SPD charge of investments approved primarily on the basis that it:

(a) is necessary to meet the N – 1 limb of the grid reliability standards;[61] or

(b) otherwise reduces expected unserved energy.

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[60] See paragraphs 7.4-7.11 for an explanation of the reasons for these proposed thresholds.

[61] The term "necessary to meet" was considered, in the context of clause 4.1 of the grid investment test, by the Court of Appeal in *Major Electricity Users' Group v Electricity Commission and Transpower New Zealand Limited* [2008] NZCA 536, [66] to [82]. The Court did not accept that "necessary to meet the N-1 standard meant "necessary to meet the N-1 standard and no more", but found that a project could be "necessary to meet" the N-1 standard even if it did more than meet that standard.

9.6 The GIT-based charge would not apply to minor or base capex proposals.

9.7 For investments that fall within category (a) or (b) (under paragraph 9.5), the GIT-based charge would recover any costs not recovered under the SPD charge.

9.8 As with the GIT-plus-SPD option:

(a) the GIT-based charge would be allocated to an "area of benefit". The area of benefit would be the load served by GXPs that benefit from the investment

(b) the allocation of the charge would be in proportion to energy consumed in the previous year's measurement period (or, in the case of industrial consumers that have their charges calculated at a substation level[62], net energy consumed).

9.9 Given the criteria set out in paragraph 9.3 and 9.5 (a) and (b) above, the following investments would be subject to both the simplified SPD and the GIT-based charge (assuming the investment has been completed):

(a) NIGU

(b) NAaN

(c) UNI reactive

(d) Otahuhu GIS

(e) USI reactive

(f) LSI reliability.

while the following investments would be subject to the simplified SPD charge only, assuming the investment has been completed:

(g) Pole 2

(h) Pole 3

(i) Wairakei Ring

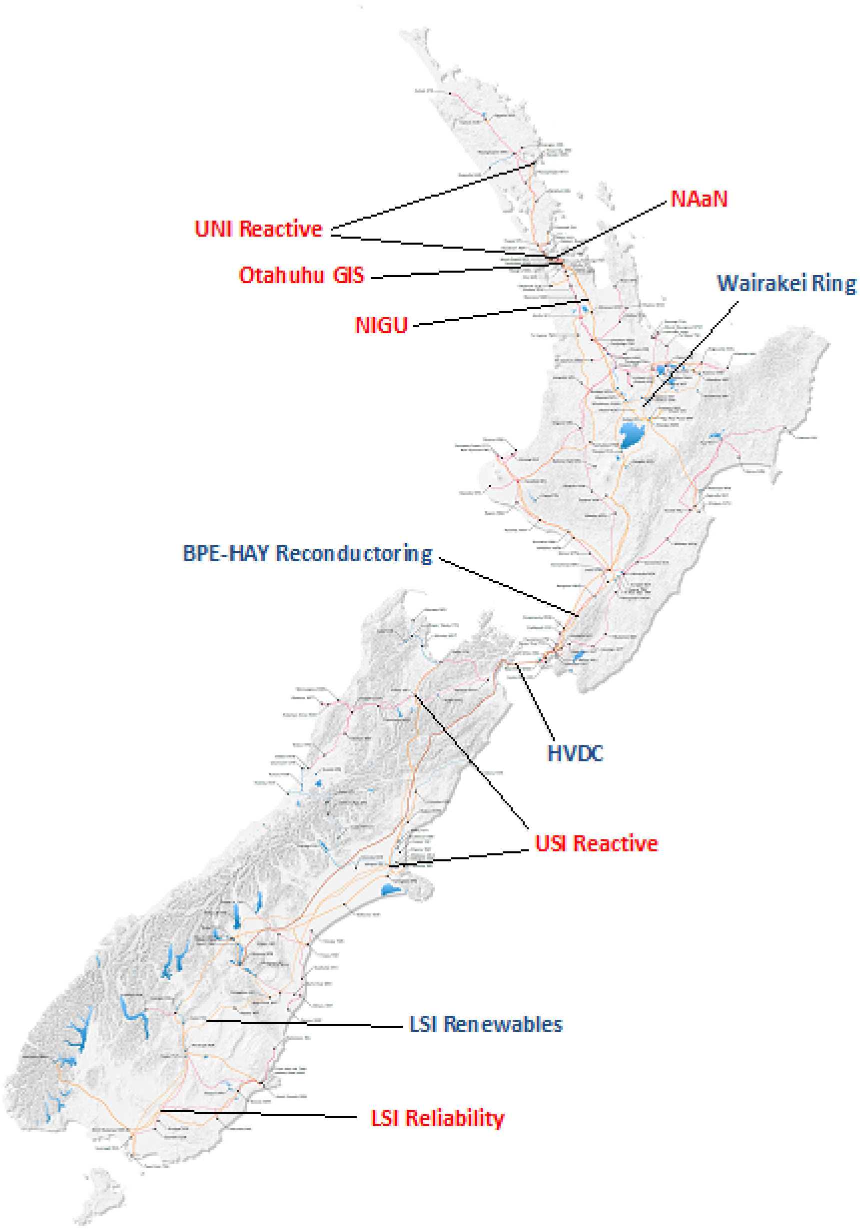
(j) LSI renewables

(k) BPE-HAY.

9.10 These investments are shown in Figure 22.

[62] See paragraphs 7.88-7.90.

**Figure 22: Assets subject to SPD-plus-GIT option (ie SPD charge and GIT-based charge (red lettering) and SPD charge only (blue lettering))**




Source: Electricity Authority

### Modelling results for SPD-plus-GIT option

9.11 The Authority has modelled this option in four ways:

(a) calculating the SPD charge applied to any party receiving gross benefits from an investment (ie charging according to benefits received from an investment and ignoring any dis-benefits), and allowing the GIT-based charge to vary each month

(b) as for (a) but fixing the GIT-based charge at a constant rate for four months

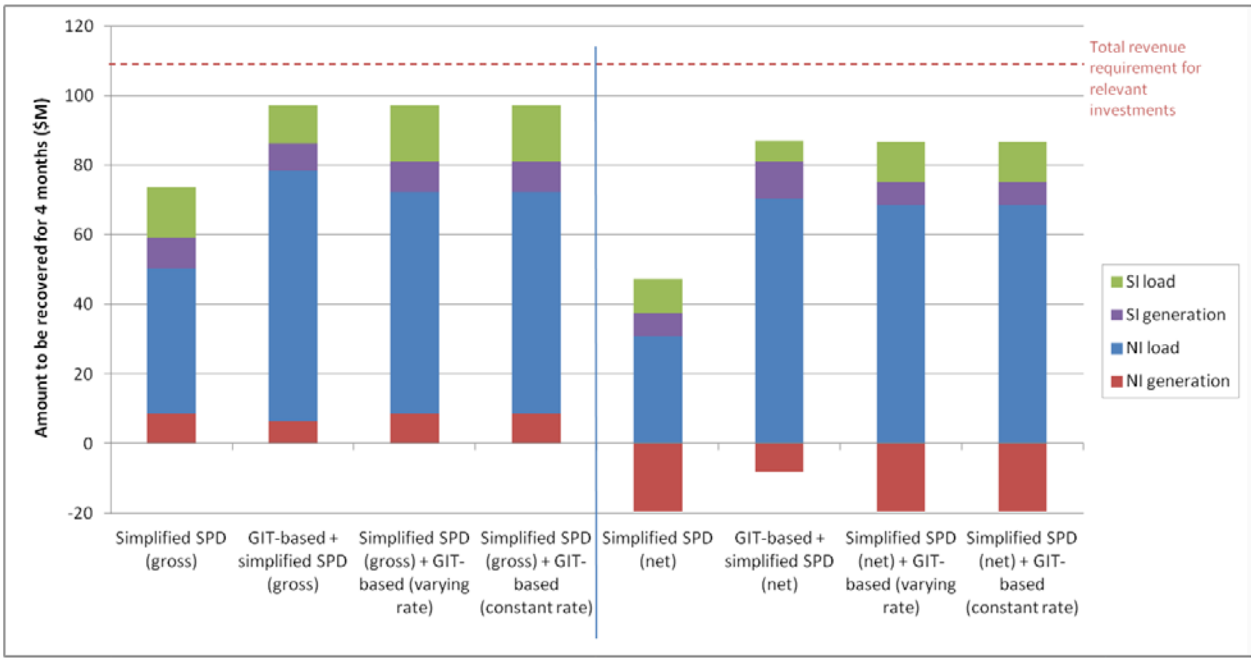
(c) calculating the simplified SPD charge using the net-benefits-with-refund (NBR) approach[63], and allowing the GIT-based charge to vary each month

(d) as for (c) but fixing the GIT-based charge at a constant rate for four months.

9.12 The options were modelled on the same basis as for the simplified SPD method using data from the 4 month period July-October 2012 inclusive.

9.13 The results for the various charging approaches and comparable simplified SPD and GIT-plus-SPD options are shown in Figure 23.

**Figure 23: Revenue recovered over four months under SPD-plus-GIT option compared with Simplified SPD and GIT-plus-SPD options**




Source: Electricity Authority

9.14 Figure 23 shows that the SPD-plus-GIT option (referred to as simplified SPD +GIT-based in Figure 22) recovers a similar proportion of total revenue to the GIT-plus-SPD option, regardless of whether the SPD charges are applied using gross benefits or the NBR approach. The main differences between the options are that:

(a) the SPD-plus-GIT option, as with the GIT-plus-SPD option, recovers more revenue than the simplified SPD option regardless of whether the SPD

[63] See paragraphs 7.33-7.39 above for a detailed description and evaluation of applying the SPD charge using the NBR approach.

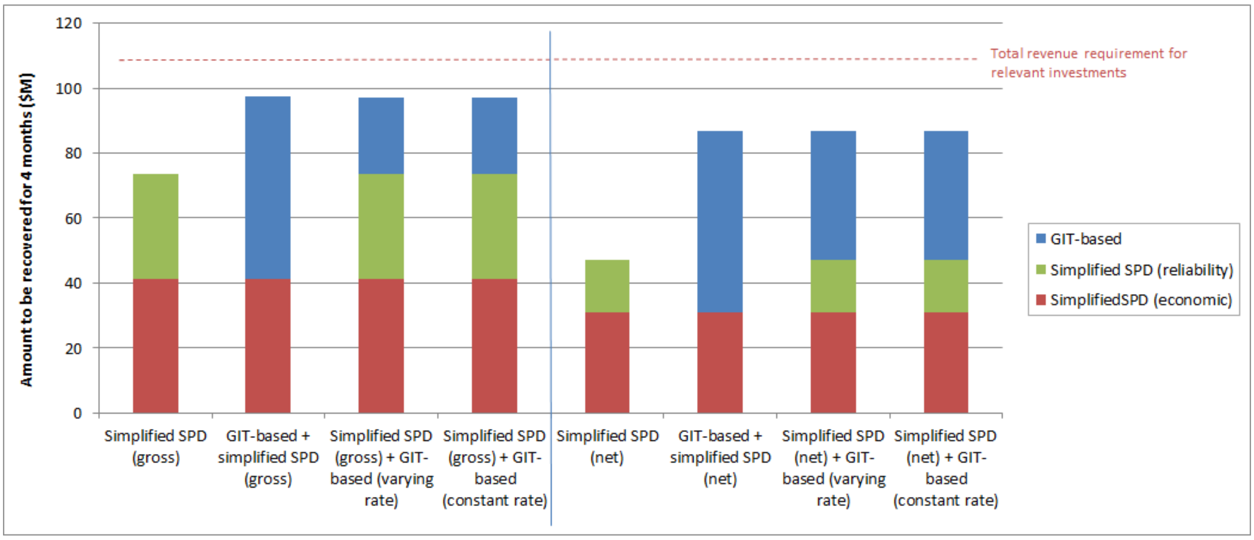
charge is calculated on a net benefits or gross benefits basis. This is because the GIT-based charge fully recovers costs of investments providing reliability benefits. (In Figure 23 the total revenue requirement is not met for the relevant investments because the SPD charge does not fully recover costs of non-reliability investments under any of the options.)

(b) the SPD-plus-GIT option recovers more revenue from South Island load and North Island generation and less revenue from North Island load than the GIT-plus-SPD option. This is because SPD charge recovers some costs of investments primarily providing reliability benefits (e.g. NAaN, NIGU) from South Island load and North Island generation as the SPD charge applies to benefits such as reduced losses. This is not possible under the GIT-plus-SPD option as the costs of investments providing reliability benefits are recovered solely under the GIT-based charge.

9.15 Figure 23 also shows that when the SPD charge is calculated under the NBR approach, South Island generation pays less and North Island generation is compensated more under the SPD-plus-GIT option than the GIT-plus-SPD option. This is because application of the SPD charge before the GIT-based charge allows dis-benefits of investments providing reliability benefits to be taken into account in determination of total charges. For this reason, the pattern of charges for generation is similar to that under the simplified SPD option when this is applied using the NBR approach, as shown in Figure 23.

9.16 Figure 24 shows the extent to which costs are recovered under the SPD charge and the GIT-based charge under the different options and the extent to which the SPD charge recovers costs of investments undertaken to improve reliability versus reduce the costs of generation (“economic”).

**Figure 24: Extent to which costs are recovered under GIT-based versus SPD charges under different options for four months**

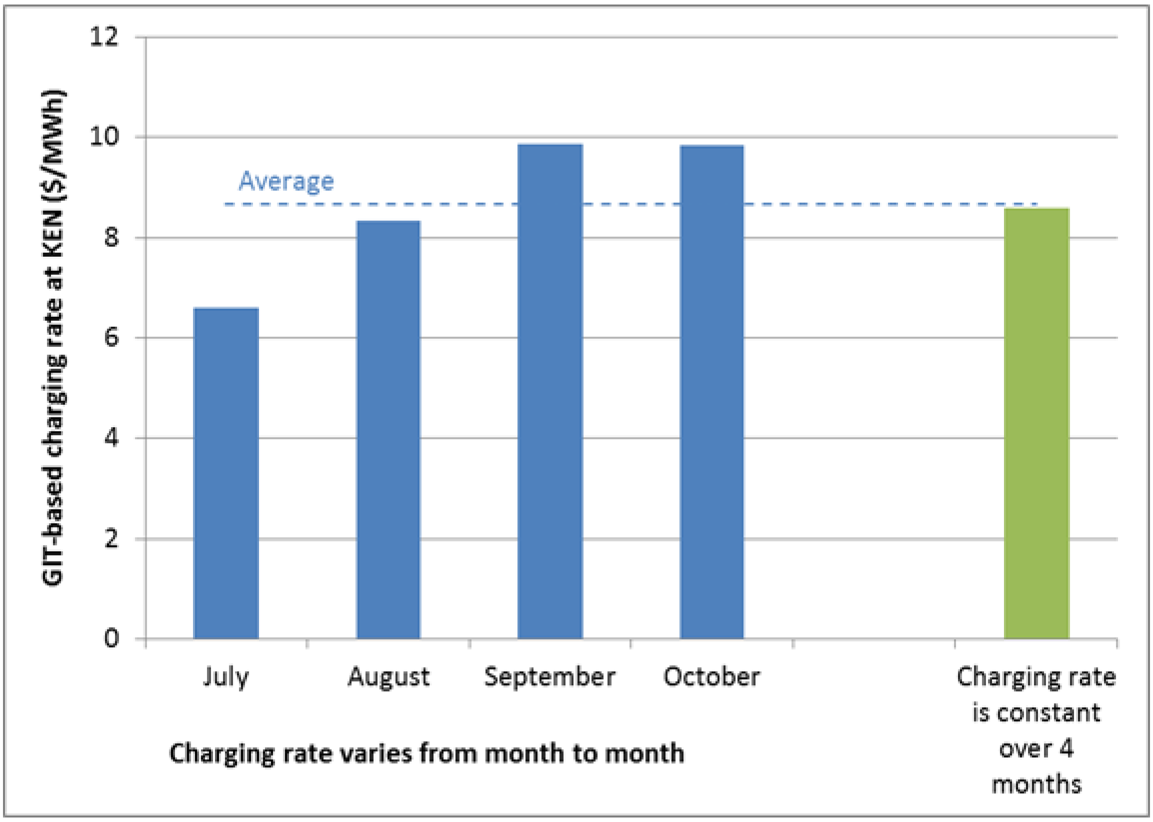



Source: Electricity Authority

9.17 Figure 24 shows that the SPD-plus-GIT approach recovers a significant portion of costs of investments undertaken to improve reliability through the SPD charge. The proportion of costs recovered under the SPD charge depends on whether the charge is calculated using gross benefits or the NBR approach. If the latter, less is recovered through the SPD charge and more is recovered through the GIT-based charge.

9.18 An issue that is specific to the SPD-plus-GIT option is whether the GIT-based charge should be fixed, as it is under the GIT-plus-SPD option, or allowed to vary. Figure 25 shows the GIT-based charge for the Kensington (KEN) node, where loads behind this node would be subject to the GIT-based charge for investments such as NAaN and NIGU.

**Figure 25: GIT-based charge for KEN node over four months**

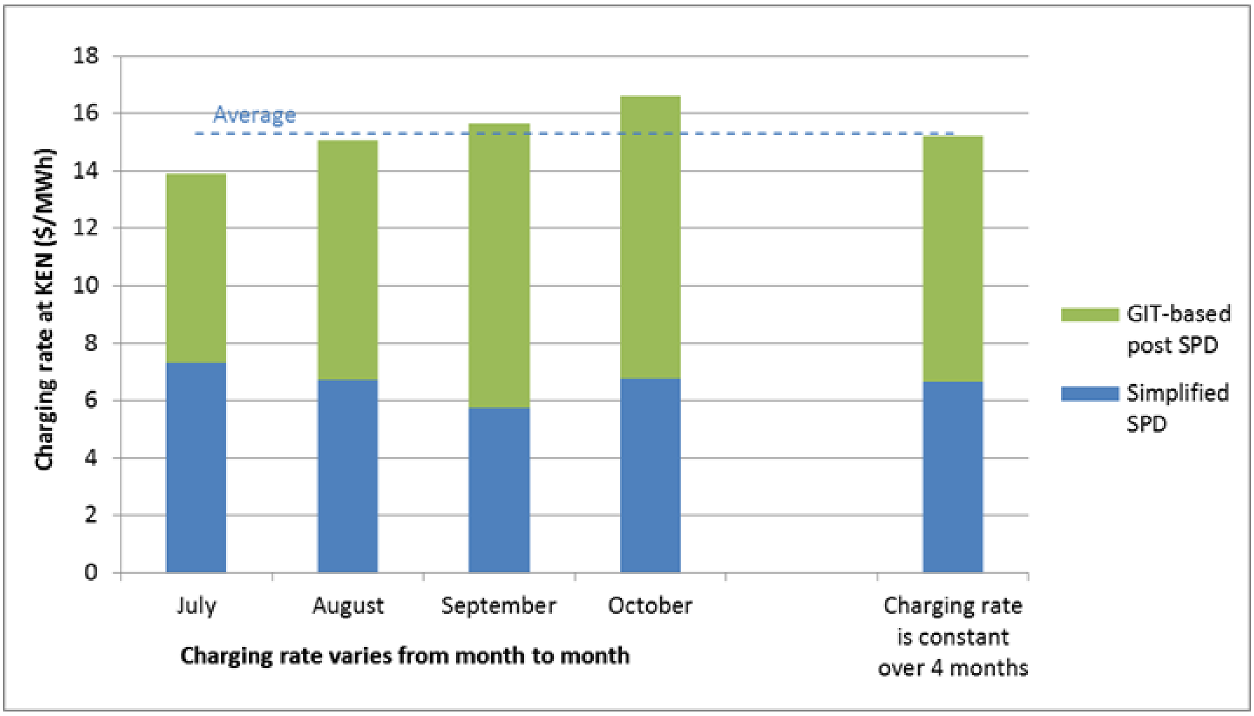



Source: Electricity Authority

9.19 Figure 25 shows that the GIT-based charge could be somewhat volatile under the SPD-plus-GIT option if it is allowed to vary from month to month. This is because the extent to which costs are recovered under the SPD charge varies from month to month.

9.20 The combination of SPD and GIT-based charges for the KEN node are shown in Figure 26.

**Figure 26: SPD and GIT-based charges for KEN node over four months**



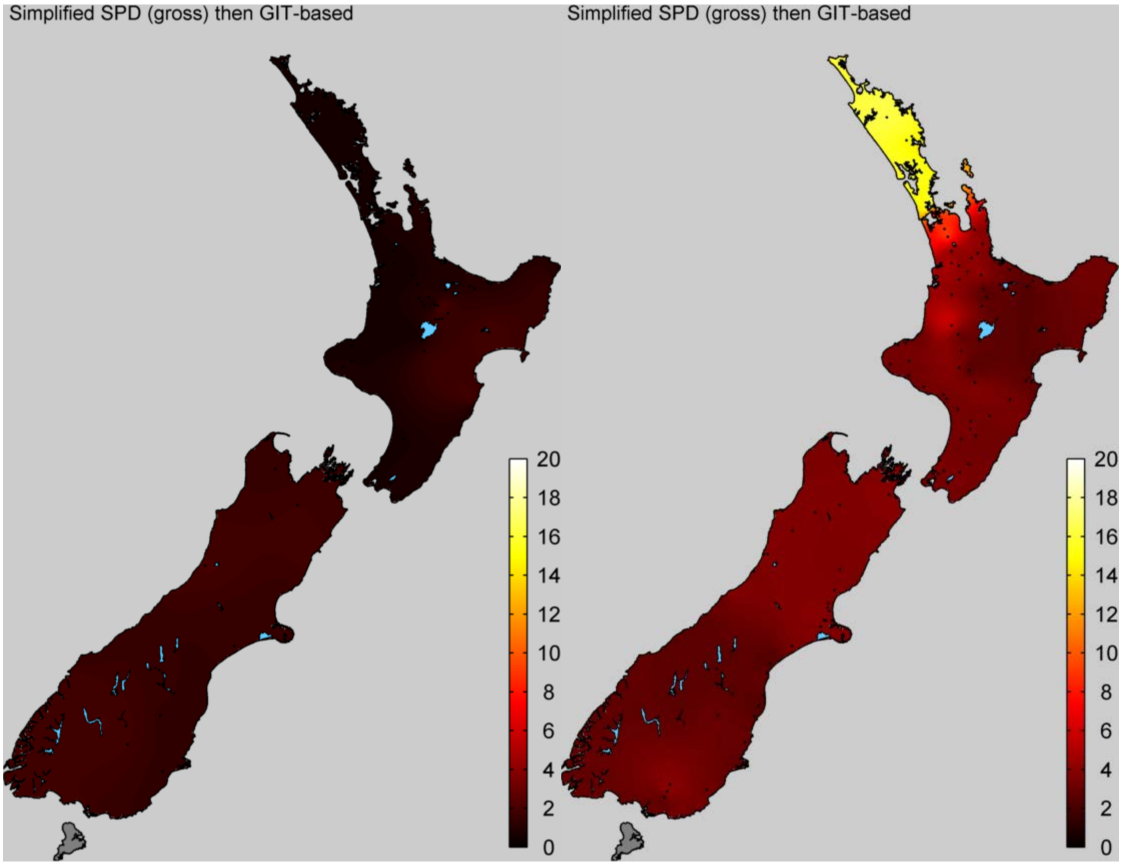

Source: Electricity Authority

9.21 Figure 26 shows that overall charges for the KEN node vary somewhat from month to month but not by a large amount, as opposed to the annual GIT-based charge, which is fixed.

9.22 The question therefore arises whether it would be preferable to fix the GIT-based charge or allow it to vary with changes in the SPD charge. Fixing the charge would provide more certainty for parties subject to the charge although it would still need to be periodically readjusted to taken into account the degree of cost recovery under the SPD charge so the added certainty from fixing the charge may be limited. A better approach may be to calculate the SPD charge on a rolling average basis which should help smooth any volatility in the GIT-based charge.

9.23 The overall incidence of the SPD-plus-GIT option for generation and load when SPD charges are calculated on a gross basis is shown in Figure 27.

**Figure 27: Regional incidence of SPD-plus-GIT option for generation (left) and load (right) for four months with SPD charge calculated using gross benefits**

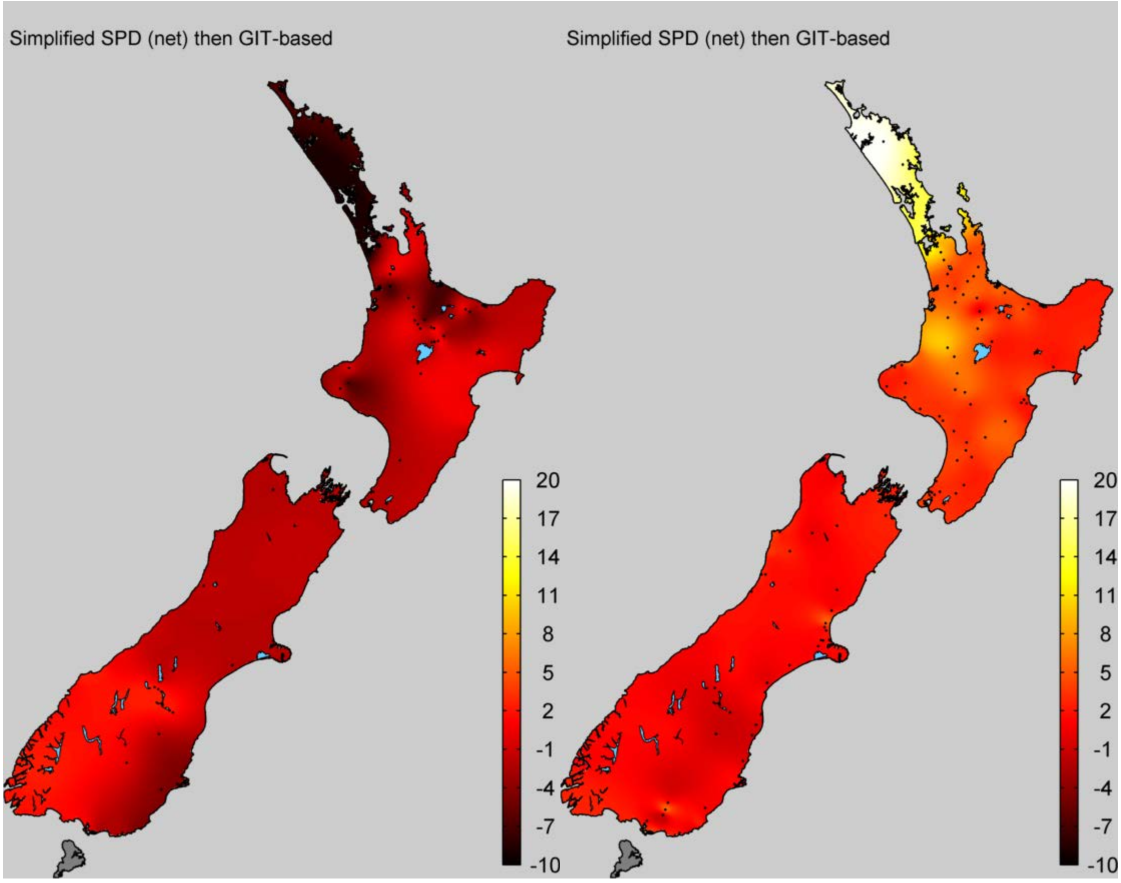



Source: Electricity Authority

9.24 Figure 27 shows that, as with the GIT-plus-SPD option, charges are highest in the upper North Island, and northern isthmus in particular, under the SPD-plus-GIT option. However, when compared to Figure 21, charges are about $4/MWh lower for upper North Island load than under the GIT-plus-SPD option (ie approximately $16/MWh under the SPD-plus-GIT option compared with $20/MWh under the GIT-plus-SPD option). The reason for this is that a greater proportion of costs is borne under the SPD-plus-GIT option by generation and load outside the upper North Island, e.g. most load faces charges of between about $5 and $7/MWh.

9.25 The overall incidence of the SPD-plus-GIT option for generation and load when SPD charges are calculated using the NBR approach is shown in Figure 28.

**Figure 28: Regional incidence of SPD-plus-GIT option for generation (left) and load (right) for four months with SPD charge calculated using NBR approach**




Source: Electricity Authority

9.26 Figure 28 shows that when the SPD charge is calculated using the NBR approach charges under the SPD-plus-GIT option are higher for upper and central North Island load (by about $4/MWh) than when the SPD charge is calculated on a gross benefit basis. Further, except in the lower South Island and parts of the central North Island, generation receives a refund under the SPD-plus-GIT option when the SPD charge is calculated using the NBR approach, as does some South Island load.

**Assessment of SPD-plus-GIT option**

***Lawfulness of using SPD-plus-GIT option to apply beneficiaries-pay charges***

9.27 The SPD-plus-GIT approach of using the simplified SPD charge to recover the costs of eligible investments to the extent possible and then using the GIT-based charge to recover remaining reliability-related costs of investments is lawful.

***Practicability of using SPD-plus-GIT option to apply beneficiaries-pay charges***

9.28 The SPD-plus-GIT option has the same practicability issues:

(a) as the simplified SPD charge in relation to recovery of that portion of costs of investments that would be recovered through the simplified SPD charge

(b) as the GIT-plus-SPD option for recovery of costs of that portion of investments that would be recovered through the GIT-based charge, except it would also be necessary to determine whether the GIT-based charge should be set on a fixed or variable basis, and if fixed for what period.

***Assessment of costs and benefits of SPD-plus-GIT option***

9.29 The benefits of the SPD-plus-GIT option are:

(a) it would provide the same efficiency benefits as the simplified SPD charge in relation to relevant investments that would be subject to the SPD charge only – that is, investments undertaken to lower the costs of generation

(b) it would better promote efficient investment in assets providing reliability benefits as the SPD charge would enable other benefits to be taken into account in beneficiaries-pay charging, and charging could reflect changing patterns in benefits over time

(c) relative to the GIT-plus-SPD charge, it would better promote:

 (i) efficiency as charging across a broader base of beneficiaries would mean lower charges to beneficiaries and a reduction in any incentives to seek to avoid the charge

(d) the GIT-based charge would:

 (i) promote efficient investment in relation to investments undertaken to provide reliability benefits as the GIT-based charge would align incentives to promote transmission investments to improve reliability with payment for those investments. This would provide strong incentives for expected beneficiaries to participate in the investment decision-making and approval process and ensure all relevant information is considered in the decision on whether to undertake the investment

 (ii) promote efficient investment by load, as allocating charges to beneficiaries of reliability investments means they would face the transmission cost implications of their investment decisions

 (iii) promote allocative efficiency as:

  - charging beneficiaries should reduce deadweight loss, as a greater proportion of the costs of transmission assets that are currently paid for under the interconnection charge would be paid for by beneficiaries. The reduction in deadweight loss would be larger than under the simplified SPD charge option as no residual charges would apply to relevant reliability investments

- it would promote efficient use of the grid as the only means of avoiding the charge would be to reduce load. This means relative to the simplified SPD charge alone there is a lower risk of inefficient behaviour to avoid the charge.

9.30 The likely costs of SPD-plus-GIT option are:

(a) it would provide the same efficiency costs as the simplified SPD charge in relation to eligible investments subject to the option

(b) it would provide the same efficiency costs in relation to the GIT-based charge as for the GIT-plus-SPD option but the quantum of costs from distortions to behaviour from the charge may be lower because of a lower charge since some of the costs would be recovered through the SPD charge

(c) the combination of application of the SPD charge and the GIT-based charge to reliability assets may increase risk of allocative efficiency costs to the extent that parties subject to the SPD charge only seek to shift costs onto parties paying the GIT-based charge.

9.31 A quantitative CBA is required to determine whether the SPD-plus-GIT option results in net benefits. However, the Authority's preliminary view is that SPD-plus-GIT option would result in net benefits over time relative to the status quo, because the option would better promote efficient investment.

***Potential to recover HVDC and interconnection costs***

9.32 The combination of the SPD charge and the GIT-based charge would enable full recovery of the costs of eligible reliability investments.

9.33 The simplified SPD charge may under-recover costs of investments subject to the SPD charge only under the SPD-plus-GIT option in the years immediately following a large transmission investment. Any costs not recovered through the simplified SPD charge or a GIT-based charge would be recovered through a residual charge. Possible designs for a residual charge are discussed in the residual charge working paper.

**Parties subject to charges under SPD-plus-GIT option**

9.34 The GIT-based charge would apply to load – that is, direct connect consumers and either retailers or distributors. The basis for deciding which of distributors or retailers should be subject to the GIT-based charge would be the same as for the GIT-plus-SPD option.

9.35 The simplified SPD charge should apply to generators, direct connect consumers, and retailers for the same reason as under the simplified SPD charge option.

**Conclusion on application of GIT-plus-SPD option**

9.36 This option would enable recovery of costs from reliability investments where capping prevents full cost recovery under the SPD charge. Further, it would reflect that the reliability benefits of the investment in the more distant future are likely to be larger, and so parties benefiting from this would have willingly paid for these costs if this were required to secure the investment.

9.37 Based on qualitative cost-benefit analysis, the Authority considers that the SPD-plus-GIT option may better promote the Authority's statutory objective of competition in, reliable supply by, and efficient operation of the electricity industry for the long-term benefit of consumers than maintaining the status quo. Quantitative cost-benefit analysis would be required to confirm this.

9.38 The key advantages of the SPD-plus-GIT charge over the GIT-plus-SPD charge are that it takes into account that the benefits of so-called reliability investments may not be confined to reliability alone, and the charge is able to reflect that the pattern of benefit and beneficiaries may change over time. Like the GIT-plus-SPD option, it enables full recovery of the costs of reliability investments that fall within the application criteria, so arguably better achieves beneficiaries pay than the simplified SPD charge alone.

# 10 Option 3 - Zonal SPD

### Overview of option

10.1 This option seeks to respond to suggestions in submissions that charging options should be simple. The zonal SPD option applies beneficiaries-pay, but in a more aggregated way than other options. Inter-zonal transmission is charged by aggregating transmission assets that enable transmission between zones, and charging according to the benefit at each node from this inter-zonal transmission. Intra-zonal transmission is charged at the same rate for all load or generation, as applicable, within the zone. This is even though the benefit from transmission at different locations within the zone and for different parties may vary. As a result, the charge may be less than, equal to, or more than each party's private benefit.

10.2 Charges under the zonal SPD option are therefore likely to provide less efficient price signals in relation to particular assets than options that set prices that more accurately reflect private benefit, but may be somewhat simpler.

10.3 This approach seeks to apply the SPD method to a simplified grid. It would require dividing the country into several zones. Each zone would be connected to other zones by an inter-zonal "interconnector" made up of the transmission assets that enable electricity to flow between the zones (or, put another way, deprival of these assets would mean electricity cannot flow between zones). The HVDC would be a separate interconnector and would comprise Pole 2 and Pole 3.

10.4 The simplified SPD method would be used to identify the benefit to each node or zone from each inter-zonal interconnector. The costs of the investments making up each interconnector would be charged according to each node or zone's share of the benefits from the interconnector (SPD inter-zonal charge).

10.5 Transmission assets that are not part of inter-zonal interconnectors would be deemed to be providing transmission services within the zone only, ie enabling transmission of electricity from generation to load within the zone. These assets would be charged only to parties within the zone on the basis that, since these assets are deemed to provide intra-zonal transmission only, the only beneficiaries of these assets are load and generation within the zone.

10.6 There are a number of ways the cost of investments providing intra-zonal transmission could be allocated (ie "within-zone charge"), including:

(a) on the basis of per MWh of load or injection in the zone

(b) on the basis of zonal peak demand or injection

(c) on the basis of congestion

(d) on the basis of capacity of connection assets used to connect the load or generation to the grid

(e) using the simplified SPD method. This could be done by establishing a zonal generation hub (comprising all generation in the zone) and a zonal load hub (comprising all load within the zone) and an intra-zonal inter-connector between the two made up of all transmission investments that enabled intra-zonal transmission between these hubs. The simplified SPD method would then be applied to each intra-zonal interconnector. Because some transmission assets provide both inter-zonal and intra-zonal transmission services, a method would be required to apportion the contribution of such assets to inter-zonal versus intra-zonal transmission. Methods are available to do this, such as participation factors,[64] but this would introduce complexity into what is intended to be a relatively simple option.

10.7 For the purposes of this working paper, only option (a) has been modelled on the basis that this is consistent with a "simple" option.

10.8 There are number of key design issues that would need to be determined for this option:

(a) definition of zones: Since this option seeks to apply the SPD method to a simplified grid, it is likely to make sense to define zones for the main load and generation centres. Decisions would be required on the size of the zones and the zonal boundaries

(b) definition of interconnectors: This would require deciding what assets should be included in each inter-connector. This would be determined by the assets that enable transmission of electricity between zones. Assets that do not enable inter-zonal transmission would be deemed to provide intra-zonal transmission

(c) charging basis for within-zone charges (see paragraph 10.6) and whether charges should be levied on generation and/or load.

**Modelling the zonal SPD option**

***Design used for modelling zonal beneficiaries-pay***

10.9 For the purpose of demonstrating the zonal SPD option, the Authority developed the following zonal SPD design:

(a) the country was divided up into the following six zones, representing the major generation and load regions: upper North Island (UNI), central North Island (CNI), lower North Island (LNI), upper South Island (USI), central South Island (CSI), and lower South Island (LSI)

(b) transmission assets were classified as either:

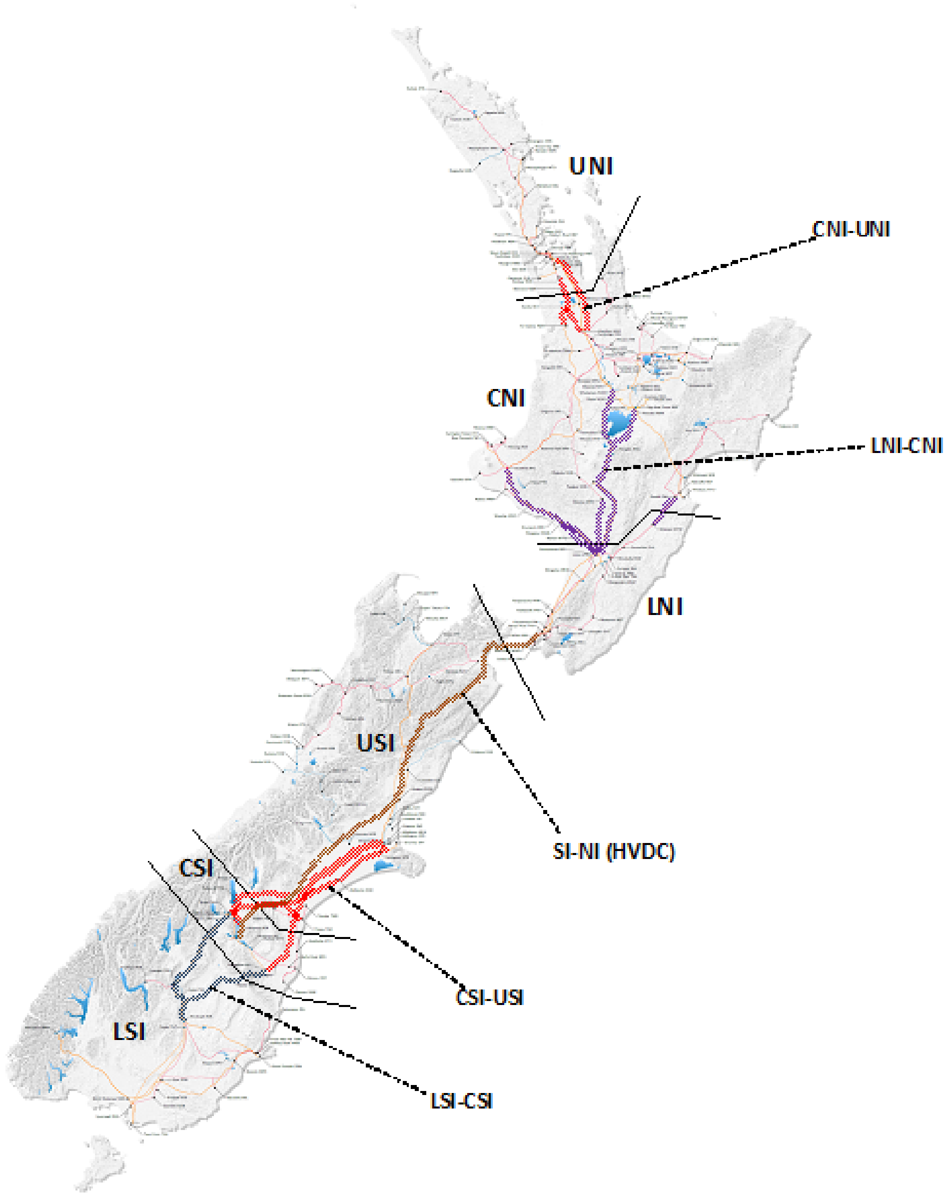
[64] Participation factors are used to determine the portion of loss and constraint excess (LCE) arising on North Island transmission assets that is used to fund financial transmission rights between Benmore and Otahuhu.

(i) falling within one of the six zones, or

(ii) connecting one of the six zones to another (forming five interconnectors, one of which is the HVDC).

10.10 The zones and interconnectors for this design are shown in Figure 29.

**Figure 29: Zones and interconnectors for modelled zonal SPD option**




Source: Electricity Authority

10.11 For modelling purposes the charges for the zonal SPD option were calculated as follows:

*SPD inter-zonal charge*

(a) for each interconnector, the simplified SPD method was applied to calculate the net benefit derived by each node in the grid

(b) the factual for the purposes of the simplified SPD method is the real grid, and the counterfactual has all assets in the interconnector removed

(c) the following prices for non-supply were applied in the counterfactual:

  (i) generally $3,000/MWh but

  (ii) $1,000/MWh for regions where non-supply is reasonably common (in the absence of the interconnector)

  (iii) $300/MWh for small areas where load cannot be served (in the absence of the interconnector)

  (iv) $150/MWh for wider areas where load cannot be served (in the absence of the interconnector)

(d) all generation offers and negative demand were removed at nodes isolated by removing the interconnector – this helps to prevent large negative prices

(e) raw allocations of SPD inter-zonal charges are scaled down for each interconnector so daily charges do not exceed the total revenue requirement of all assets making up the interconnector.

*Within-zone charges*

Two within-zone charges were applied:

(a) within-zone asset charge: for each zone, a per-MWh charge is calculated on all (positive net) injections and (positive net) offtakes within that zone, by pro-rating the total revenue requirement for assets falling within that zone

(b) non-asset-specific charge: a per-MWh charge on all (positive net) injections and (positive net) offtakes, by pro-rating the non-asset-specific part of Transpower's revenue requirement. (This excludes all the costs already allocated above, plus connection costs and static reactive asset costs.) Note that, while this was modelled as a separate charge it could also just be a component of the within-zone charge and/or inter-zonal charge, as is the case with connection and HVDC charges.[65]

***Modelling results for zonal SPD option***

10.12 The zonal SPD option was modelled on the same basis as the other two options using data from the period July-October 2012. SPD charges were calculated using gross benefit and daily capping.

[65] These costs are also covered in the current interconnection charge. However, unlike the connection and HVDC charge, they are not calculated separately as the revenue to be recovered by the interconnection charge is just the costs remaining in relation to AC assets after connection charges have been applied. This includes non-asset-specific costs not recovered under connection charges.

10.13 The incidence of SPD inter-zonal charges for each interconnector are presented in Appendix E. Key points to note are:

(a) charges tend to fall mainly on load rather than generation

(b) charges tend to fall on load in the zone that benefits from import of power as a result of the interconnector

(c) to the extent that other load pays for the charges it is mainly because of benefit from reduced losses as a result of the interconnector or flow in the reverse direction on the interconnector

(d) generation from outside the zone receiving the import benefits from the interconnector bears most of the interconnection charges from generation

(e) charges for the CNI-UNI interconnector include the costs of NIGU but not NAaN, as the latter was not included in this interconnector since it was not required for transmission of power between the CNI and UNI zones

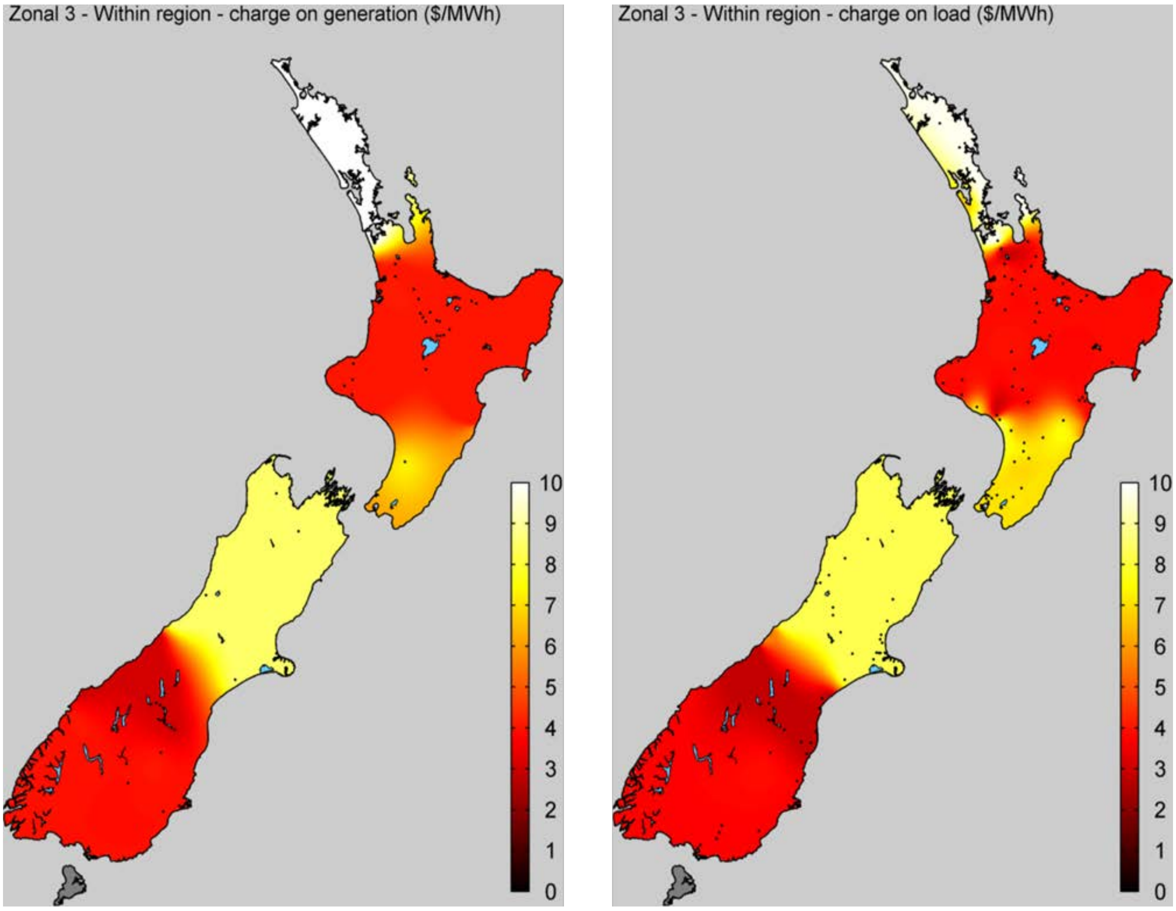
(f) costs of the Wairakei Ring were recovered through the CNI intra-zonal charge

(g) charges for the LSI-CSI interconnector include the costs of the LSI renewables project

(h) the SI-NI interconnector includes both Pole 2 and Pole 3 so the allocation of charges is different than under the simplified SPD charge option.

10.14 The incidence of the within-zone charges for generation (left) and load (right) is shown in Figure 30. A key point to bear in mind is that these charts show charges to recover the costs of all transmission except the costs for interconnectors.

**Figure 30: Incidence of within-zone charges for 4 months**



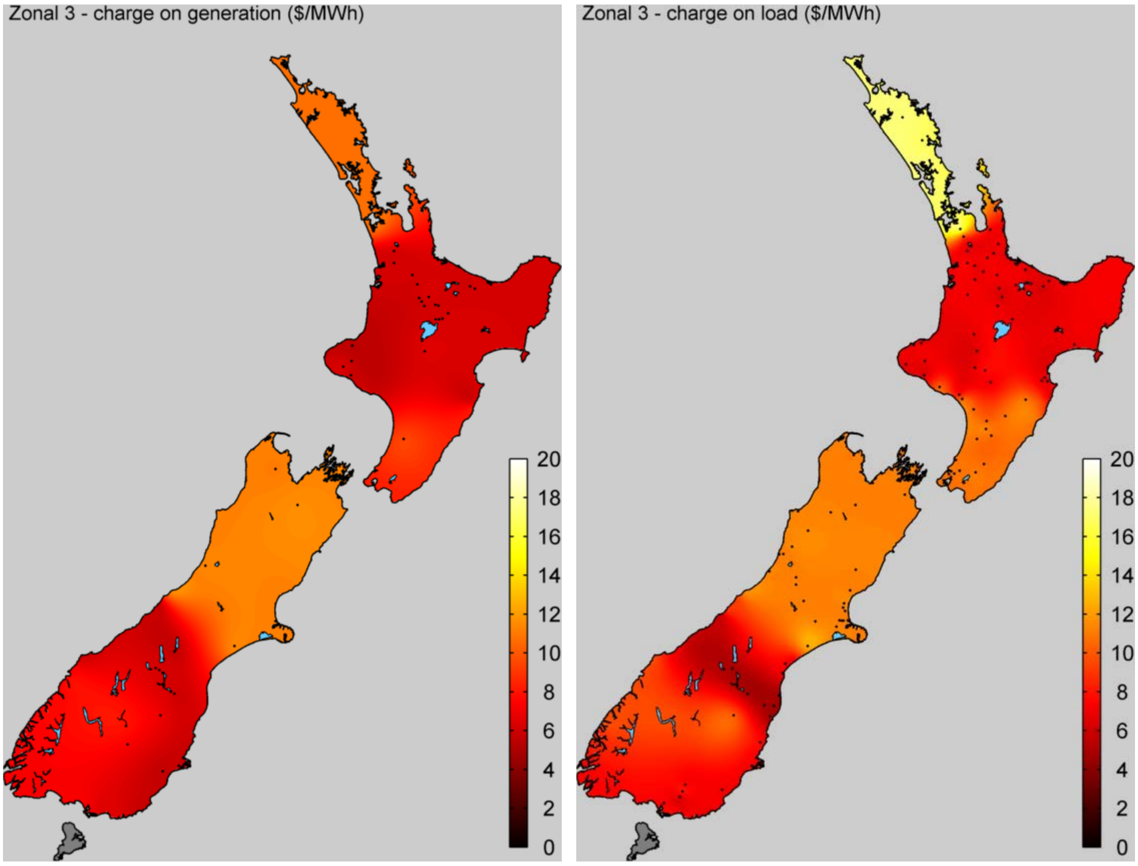

Source: Electricity Authority

10.15 Figure 30 shows that the rate of the within-zone charge in $/MWh terms is the same for generation and load. These charges are likely to be only a proxy for benefit.

10.16 Figure 30 shows that within-zone charges tend to be higher where there has been significant within-zone transmission investment – the UNI and USI zones.

10.17 The overall incidence of charges under the zonal SPD option– ie inter-zone and within-zone charges combined – is shown in Figure 31.

**Figure 31: Overall incidence of charges under zonal SPD option for 4 months**




Source: Electricity Authority

10.18 It is important to bear in mind that these charts show the full allocation of Transpower's costs excluding connection and static reactive support assets charged through a kvar charge. Charges will therefore be higher than for the simplified SPD charge and both the GIT variation options.

10.19 The incidence of the charges is similar to the within-zone charges, reflecting the magnitude of these charges relative to inter-zone charges.

10.20 Load bears higher costs than generation, though because of the significance of the within-zone charges, the relativity between load and generation is not as large as other options.

10.21 As for the within-zone and inter-zone charges, total charges tend to be higher in areas that have had significant transmission investment and/or where there is relatively little generation relative to load.

10.22 A key point to note is that a new transmission investment would only raise charges for zones benefiting from the investment – e.g. the costs of an investment to improve reliability for the upper South Island would largely be borne by upper South Island load. It would not raise charges in all zones. This means that this option would help promote efficient investment as parties benefiting from the investment – at least to the extent that this option charges costs to beneficiaries – would face the costs of the investment.

### Assessment of zonal SPD option

#### *Lawfulness of using zonal SPD option to apply beneficiaries-pay charges*

10.23 The zonal SPD approach of recovering the transmission costs through an interconnector charge and a within-zone charge is lawful.

#### *Practicability of using zonal SPD option to apply beneficiaries-pay charges*

10.24 The key practicability issues with a zonal SPD option are:

(a) determining and defining zones. This could involve using the current transmission pricing zones or developing a methodology to define zones and zonal boundaries

(b) determining and defining interconnectors. A methodology would need to be developed to identify transmission assets that enable transmission of power between zones and therefore would be included in inter-zonal interconnectors. Methodologies such as flow tracing or use of participation factors could assist with this

(c) determining whether application of the simplified SPD method to inter-zonal interconnectors would be based on benefit to the zone or benefit at a node

(d) determining the basis for applying within-zone charges

(e) determining whether within-zone charges would be levied on load and/or generation.

10.25 The practical issues with this option are likely to be greater than the other two options considered as more judgement is likely to be required in the design of the key aspects of the charge.

#### *Assessment of costs and benefits of zonal SPD option*

10.26 The benefits of zonal SPD option are:

(a) it would promote efficient investment in transmission as parties benefiting from the investment – at least to the extent that this option charges costs to beneficiaries and according to their private benefit – would face the costs of the investment. This would be the case for investment that enables both transmission of power between zones and within zones. This would provide incentives on beneficiaries to participate in the investment decision-making and approval process and ensure all relevant information is considered in the decision on whether to undertake the investment

(b) efficient investment by generation and load, as allocating charges to beneficiaries – to the extent this option charges costs to beneficiaries according to their private benefit – means they would face the transmission cost implications of their investment decisions

(c) allocative efficiency through reduction in deadweight loss, as a greater proportion of the costs of transmission assets that are currently paid for under the interconnection charge would be paid for by beneficiaries. The reduction in deadweight loss would depend on the extent to which beneficiaries are charged and the charges reflect aggregate benefit

(d) productive efficiency as parties would not have incentives to limit their production in order to limit their charge liability as they do under the status quo.

10.27 The likely costs of the zonal SPD option are:

(a) implementation costs are likely to be high for both Transpower and participants, including set-up costs involved in designing and implementing the option, including computer equipment, any licence costs, development and testing

(b) dispute costs from establishment of zones and interconnectors

(c) operational costs to Transpower, or to a party other than Transpower if the role of applying the method to calculate inter-zonal charges was subject to tender, including the on-going costs of applying the option to estimate the benefits from transmission assets

(d) costs to participants to verify their charges

(e) inefficient investment to the extent that charging does not reflect benefit and does not reflect LRMC

(f) allocative and productive inefficiency to the extent that charging does not reflect benefit and does not reflect LRMC

(g) incentives for inefficient avoidance of the charge. This would need to be addressed through the design of the charge or through other mechanisms, such as the prudent discount policy.

10.28 A quantitative CBA is required to determine whether the zonal SPD option results in net benefits. However, through better promoting efficient investment than the status quo, the Authority's preliminary view is that the zonal SPD option would result in net benefits over time relative to the status quo.

***Potential to recover HVDC and interconnection costs***

10.29 The zonal SPD option would fully recover HVDC and interconnection costs.

### Parties subject to charges under zonal SPD option

10.30 Inter-zonal charges would apply to generation, direct connect consumers and either retailers or distributors. Retailers are likely to be the more efficient agent for inter-zonal charges for the same reason as for the simplified SPD charge.

10.31 Since both generators and load benefit from within zone transmission the Authority proposes that both would be subject to within-zone charges – generators, direct connect consumers and retailers or distributors. Whether distributors or retailers are the most efficient agent for end consumers is likely to depend on the design of the charge. If it is SPD-based, retailers are likely to be the more efficient agent. If it is charged according to connection capacity, peak, congestion or MWh distributors may be the more efficient agent. In the case of peak or congestion, this is in part because of their ability to manage peaks or congestion, although this may change with advanced metering. Quantitative cost-benefit analysis would be needed to confirm which party is the most efficient agent.

### Conclusion on application of zonal SPD option

10.32 The Authority considers that the zonal SPD option would better promote the Authority's statutory objective of competition in, reliable supply by, and efficient operation of the electricity industry for the long term benefit of consumers than maintaining the status quo.

10.33 This option is deliberately designed to apply beneficiaries-pay in a more aggregated manner than other options. This means it is likely to provide more muted price signals than the other options. This is likely to mean that the incentives for more efficient investment are more muted than the other options.

10.34 On the other hand, this option applies at least a crude form of beneficiaries-pay to all assets. To the extent the resulting price signal is more efficient than residual charges, this option may better promote more efficient investment than the combination of one of the other options and a residual charge. Quantitative cost-benefit analysis would be needed to establish this.

10.35 The key benefit of this option relative to other options is that there are less “moving parts”. If a similar option to the one modelled was implemented, parties facing transmission charges would need to understand the benefit they received from just five interconnectors plus the within-zone charge. This compares with understanding the calculation of SPD charges for at least ten investments plus the residual charge in the case of the simplified SPD method.

10.36 A critical issue with the zonal SPD option is the definition of zonal boundaries and zonal interconnectors. The identification of zonal boundaries would inevitably involve judgment. Extensive lobbying is likely in the definition of zonal boundaries because of the cost impact of transmission charges. This suggests that implementation costs of this approach are significantly greater than the simplified SPD charge and GIT-based options.

10.37 As with a GIT-based option, elements of this option could be incorporated into a final TPM proposal. For example, the concept of interconnectors could be incorporated into the final proposal along with a residual charge. Alternatively, the simplified SPD charge and the GIT-based charge could be combined with the within-zone charges in the zonal SPD option. As with other options, quantitative cost-benefit analysis would be required to determine whether such options provided net benefits.

# 11 Assessment and conclusion

11.1 This working paper has described three options for beneficiaries-pay charges for recovering the costs of some of the assets currently subject to interconnection and HVDC charges.

11.2 Two of the options – the simplified SPD charge and the GIT-based option – apply beneficiaries pay in a granular way by applying charges based on the benefit parties obtain from particular investments. The third option, zonal SPD, applies beneficiaries-pay in an aggregated way across multiple assets.

11.3 As a result, the first two options are likely to provide sharply defined price signals in relation to each investment to which they relate. This means that the price signal in relation to a new investment will be clear, providing clear signals for efficient investment.

11.4 The price signal from the zonal SPD option would be more muted. The costs of a new investment would be spread across a broader base, particularly if it is an investment that has its costs recovered through the within-zone charge. As a result, the price signal will not be as clear so the incentives on beneficiaries would be dulled somewhat relative to the other options. This implies that this option may be less effective at promoting efficient investment than the other options.

11.5 On the other hand, the zonal SPD option applies a form of beneficiaries-pay across all assets. This means that the price paid by a transmission customer for transmission is more likely to reflect the benefit they receive in aggregate from all transmission assets compared with the other two options. Overall, therefore, the zonal SPD option could better promote efficient investment. This is because the other two options provide prices accurately reflecting benefit for some assets but unrelated to benefit for other assets, where the costs are recovered through the residual charge. Quantitative cost-benefit analysis would be required to determine whether this is the case.

11.6 Based on the modelling for the 4 month period used in this working paper, the residual revenue that would need to be recovered for a period of 12 months under each of the options is set out in Table 4.

**Table 4: Summary of residual revenue under each option**

| Option | Residual revenue |
|---|---|
| Simplified SPD | $552M |
| GIT-plus-SPD | $483M |
| SPD-plus-GIT | $483M |
| Zonal SPD | Total zonal SPD “residual” costs: $468m. This is made up of:<br>• $183M (non-asset-specific costs)<br>• $285M (total within-region asset specific costs allocated using within-zone charges) |

Source: Electricity Authority

11.7 Table 4 indicates that zonal SPD has the smallest residual of the three options, even if the within-zone charge was classed as part of the residual charge.

11.8 As noted earlier in this paper, combinations of the options may better promote efficient investment than the options described in this paper. For example, application of the within-zone charges, described under the zonal SPD option to pre-2004 assets , and the simplified SPD charge and/or GIT-based charge for post-2004 investments, might result in greater net benefits than the options presented in this paper.

11.9 A number of submitters have noted that some beneficiaries-pay options may change the way parties use the grid. In principle, this should not be the case provided a beneficiaries-pay charge to a party does not exceed their private benefit. However, in practice, parties may still alter their use of the grid to avoid the charge if they have options that allow them to do this while still obtaining the benefits. This risk is more acute with methods that determine benefit to a party and therefore the charge over time, e.g. the simplified SPD method. The GIT-based charge largely avoids this problem by determining beneficiaries and the parties subject to the charge prior to investment. Further, especially under the GIT-plus-SPD option, the charge is largely fixed prior to the investment, only varying because of changes in the share of demand. The within-zone charge under the zonal SPD option could have similar advantages if it is charged on the basis of demand or injection.

11.10 Two key advantages of the GIT-based charge compared with the simplified SPD charge are that it ensures full recovery of the costs of reliability investments using a beneficiaries-pay approach. The zonal SPD option also has these advantages but for within-zone investments it is not certain that beneficiaries will be charged, nor that the charges to beneficiaries reflect their private benefit.

11.11 The options have different degrees of complexity. While all options utilise the simplified SPD charge to recover some costs, the number of assets/investments subject to this charge varies. For the simplified SPD charge and SPD-plus-GIT options there are ten existing/known investments under the thresholds proposed in this paper for application of the charge plus new investments. For the GIT-plus-SPD option there are five investments, while under zonal beneficiaries-pay five interconnectors would be subject to this charge. On the other hand, the simplified SPD charge option involves no other beneficiaries-pay charges but would require a residual charge. The other options do involve other charges: the GIT-based charge would also require a residual charge, while the zonal SPD option also has the within-zone charge (and, in the option modelled the non-asset-specific charge, though as noted, these costs could be recovered through the within-zone charges).

11.12 The implementation costs of the different options will vary. All of the options would involve the costs of calculation of the SPD charge, although the computational costs of the simplified SPD charge and GIT-based option may increase over time as new investments become subject to the charge. Countering this though is the more general fall in computational costs over time. Both variations of the GIT-based option would also involve costs in identifying the primary benefit of an investment, and the beneficiaries that would be subject to the GIT-based charge. The zonal SPD option is likely to involve high initial implementation costs, as zones and interconnectors would need to be defined and the basis for within-zone costs determined.

11.13 Participation costs of the different options are similar since all will require familiarity with the SPD method in order to understand charges. While the GIT-based and zonal SPD options involve additional charges, these charges should be relatively simple to understand.

11.14 In terms of other costs, the most significant is the risk that increased charges under these options may result in inefficient disconnection in order to avoid the charge. This risk is greatest under the GIT-based charge under the GIT-plus-SPD option, and to a slightly lesser extent with the combination of SPD and GIT-based charges under the SPD-plus-GIT option, as these options would cause significant increases in charges for upper North Island customers. However, it is important to note that it is not necessarily the case that all such disconnection would be inefficient. Where the charge reflects LRMC and the customer can obtain electricity to the reliability they require using a technology that does not involve transmission but for a lower cost, disconnection would be efficient.[66] Even so, under the current transmission regulatory regime the transmission costs would still need to be recovered – potentially from non-beneficiaries.

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[66] This is no different from somebody choosing to communicate by email rather than fax because the costs are lower. The difference between this example and transmission is that it is likely the costs of the fax machine will be fully recovered but the costs of transmission investments may not be, giving rise to a risk of stranded assets.

11.15 The overall assessment of these options is summarised in Table 5. The assessment criteria were developed from submissions on the October 2012 issues paper and from the Authority's economic and decision making framework paper.

**Table 5: Summary of assessment of beneficiaries-pay options**

| | October 2012 SPD proposal | *Simplified SPD* | *GIT-plus-SPD* | *SPD-plus-GIT* | *Zonal SPD* |
|---|---|---|---|---|---|
| Prices reflect benefit of investment | Yes | Yes | Yes | Yes | Partial |
| Extent of application of beneficiaries-pay | Partial | Partial | Partial, though greater than Simplified SPD alone as applies beneficiaries pay to reliability benefits | Partial, though greater than Simplified SPD alone as applies beneficiaries pay to reliability benefits | Partial |
| Recovery of costs of reliability investments | Partial | Partial | Full | Full | Full |
| Simplicity | 5th | 3rd | 2nd. Calculation of GIT-based charge is simple. SPD charge only applied to subset of assets | 4th. Same assets subject to SPD charge as Simplified SPD but also subject to GIT-based charge | 1st. SPD charge only applies to five interconnectors. Simple within-zone charge. |

| | October 2012 SPD proposal | *Simplified SPD* | *GIT-plus-SPD* | *SPD-plus-GIT* | *Zonal SPD* |
|---|---|---|---|---|---|
| Avoid altering use of the grid | Partial | Partial. Since SPD charge is based on market outcomes incentives may exist to alter grid use to avoid the charge | Partial. Less ability to alter use of the grid to avoid GIT-based charge | Partial. Combination of SPD plus GIT-based charge may mean incentive on parties paying SPD charge to shift costs on to payers of GIT-based charge. less ability to alter use of grid to avoid GIT-based charge | Partial |
| Incentives for evolution of more efficient charging over time | Yes – provides information that enables development of more efficient charging | Yes – provides information that enables development of more efficient charging | Yes – provides information that enables development of more efficient charging | Yes – provides information that enables development of more efficient charging | Partial – interzonal SPD charge provides information that enables development of more efficient charging |
| Costs involved in implementing option | Development of SPD charge only | Development of Simplified SPD charge only | Development of Simplified SPD charge plus application of GIT-based charge | Development of Simplified SPD charge plus application of GIT-based charge | Development of Simplified SPD charge for interconnectors plus identification of zones and interconnectors and development of within zone charge |

| | October 2012 SPD proposal | *Simplified SPD* | *GIT-plus-SPD* | *SPD-plus-GIT* | *Zonal SPD* |
|---|---|---|---|---|---|
| Incremental participation costs | Need to understand application of SPD charge to multiple assets | Need to understand application of SPD charge to multiple assets | Need to understand application of SPD charge to some assets plus need to understand (simple) GIT-based charge | Need to understand:<br>• application of SPD charge to some assets<br>• GIT-based charge<br>• effect of combination of charges | Need to understand application of SPD charge to interconnectors plus need to understand (simple) within-zone charge |
| Other costs | | Low risk of inefficient disconnection | Medium risk of inefficient disconnection | Medium risk of inefficient disconnection | Low to medium risk of inefficient disconnection |

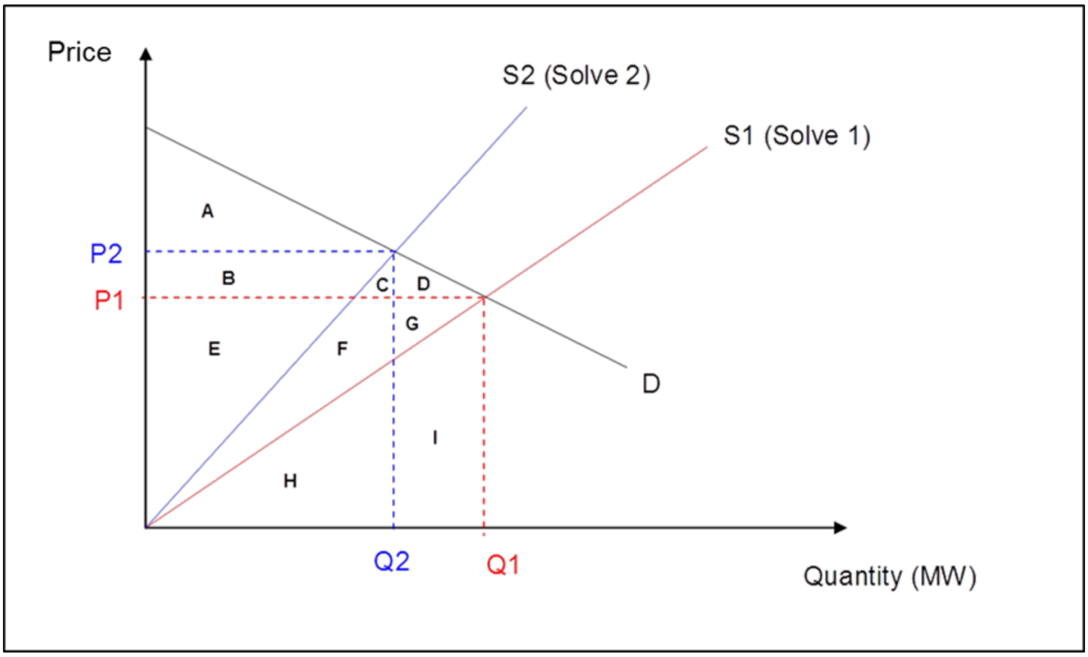
Source: Electricity Authority

11.16 In conclusion, determining which option delivers greatest net benefits would require quantitative cost benefit analysis. The Authority intends to develop a refined option or options based on feedback on this working paper and the other working papers. Quantitative cost-benefit analysis would be applied to the Authority's preferred option and an alternative or alternatives in the second issues paper.

# Appendix A Conceptual explanation of SPD method

A.1 The *concept* behind calculation of the charge is illustrated in Figure 32:

**Figure 32: Conceptual illustration of calculated benefits from SPD solve**




Source: Electricity Authority

A.2 Figure 32 shows a demand curve, D, and two supply curves, S1 and S2. As some submitters on the October 2012 issues paper pointed out, the slope of the supply curves and demand curve used in the Authority's issues paper proposal differed to the slope for these curves shown in Figure 32 (e.g. the demand curve was vertical up to the cost of unserved energy, which was $3000/MWh in the proposal, at which point it was horizontal). The slope used for the demand curve, in particular, is one aspect that the Authority is proposing to change in its simplified SPD charge, as discussed further below.

A.3 S1 is the supply curve with the grid asset installed (i.e. solve 1 of SPD) and S2 is the supply curve with the grid asset replaced by the pre-investment stated in the SPD model and security constraints reconfigured (i.e. solve 2). Figure 32 illustrates that the installation of the asset may increase the quantity of electricity that can be supplied from Q2 to Q1 and may reduce prices from P2 to P1.[67]

A.4 Measuring the monetary benefit to load from the asset involves comparing the area under the demand curve but above the price for solve 1 (i.e. areas A, B, C and D) with that for solve 2 (i.e. the area given by A alone). Measuring the monetary benefit to generation involves the opposite: comparing the area above the supply curve but below the price for solve 1 (i.e. areas E, F and G) with that for solve 2 (i.e. the area given by B and E). This is summarised in Table 6.

[67] Note that Q1 & P1 are the actual wholesale market outcomes and Q2 & P2 are simulated market outcomes that could have occurred if the grid asset had not been installed.

**Table 6: Summary of calculation of benefits using SPD**

| | Solve 1 | Solve 2 | Change |
|---|---|---|---|
| Demand (offtake) | A + B + C + D | A | B + C + D |
| Supply (injection) | E + F + G | B + E | F + G – B |

Source: Electricity Authority

A.5 In other words, the calculation would be an estimate of the monetary value a party derived from the asset being available.

A.6 It is important to bear in mind that Figure 32 and Table 6 illustrate an example that results in the SPD method showing positive benefits for both load and generation. However, the SPD method can, and often does, also result in positive benefits to either load or generation or net negative benefits to one or both kinds of parties.

# Appendix B Other options considered

**Less complex SPD method:**

B.1 Under this option, charges are calculated by considering the benefit that parties receive from the presence of the grid as a whole compared with its absence.

B.2 The factual case is based on actual final pricing using SPD.

B.3 The counterfactual case assumes that the entire transmission grid is unavailable. In this case:

(a) generators are not dispatched, or are dispatched at a zero price, and

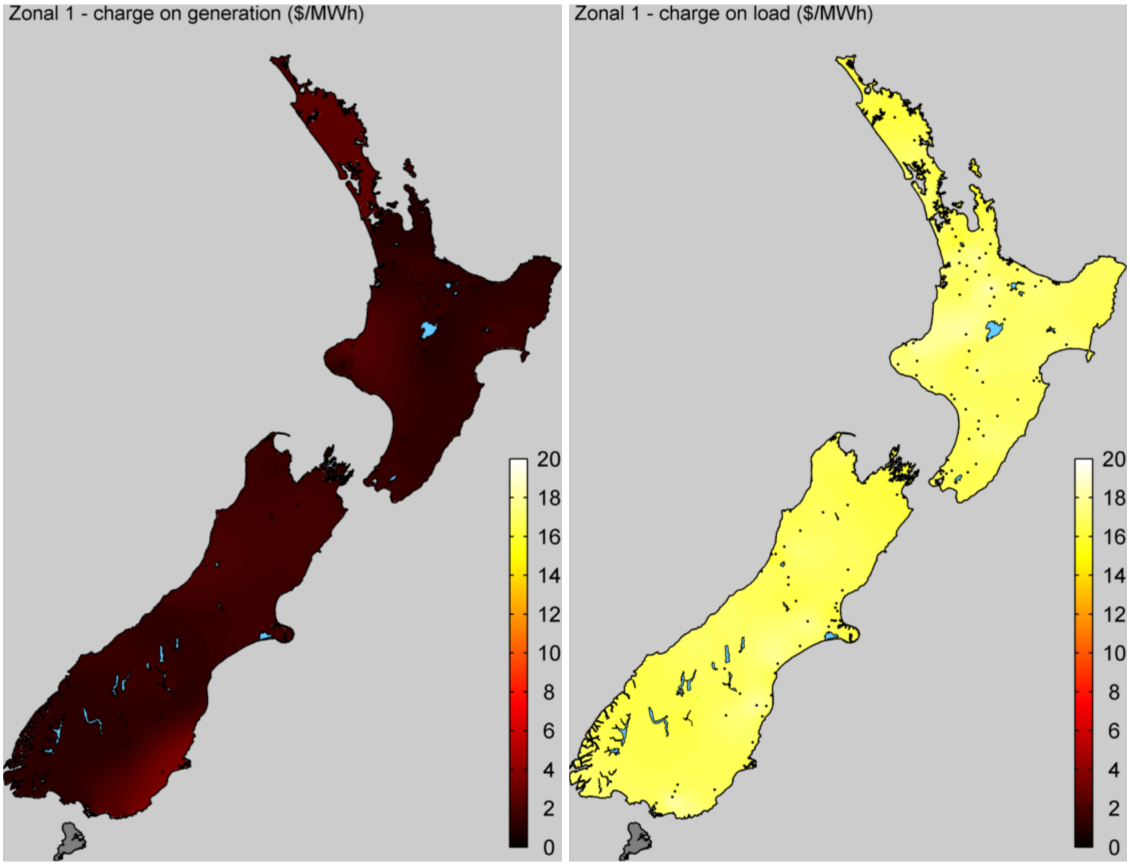
(b) consumers pay the assumed LRMC of generation that could be constructed in their area.

B.4 Under this method, each party's generation or load quantity at each node is multiplied by the difference between the actual spot price and the counterfactual price to determine the benefit from the presence of the grid.

B.5 Each party's transmission charge is therefore their share of total benefits multiplied by the revenue to be recovered under the TPM. For example, if the revenue to be recovered is $1B per year and their share of the estimated benefit is 1/100, then their transmission charge is $10m per year.

B.6 Charges that might result from the application of this method (depending on the parameters used) are shown in Figure 33.

**Figure 33: Charging rates under the less complex SPD method**




Source: Electricity Authority

B.7 This method is not preferred because it spreads the revenue requirement of each investment across the entire grid, rather than recovering the cost from beneficiaries of that investment.

**Import or export benefits approach**

B.8 This approach seeks to allocate costs in a way that reflects the fact that much of the cost of grid investment is to enable transmission of power between regions. Under this approach benefits would be determined on a regional basis according to whether a region is importing or exporting over the time period used to determine the charge. Load in net exporting regions and generation in net importing regions would not face beneficiaries-pay charges.

B.9 For example, if South Canterbury (a net exporting region) were a region for transmission charging purposes, only generation would face beneficiaries-pay charges for the region - load in the region would not. Similarly, if the upper South Island (Buller, Nelson and Marlborough) were a region, only load in the region would pay beneficiaries-pay charges - generation would not. This means that transmission supplying load in exporting regions such as South Canterbury would be paid for by other parties. The same would apply to transmission exporting generation in importing regions such as the upper South Island.

B.10 Implementing this approach would first require mapping nodes to regions. For each charging period, regions would be divided into net importers and net exporters according to whether regional load exceeds regional generation or vice versa.

B.11 For each region, benefits would then be calculated based on a comparison of factual and counterfactual cases.

B.12 As in the less complex SPD method, the factual case is based on actual final pricing using SPD.

B.13 The counterfactual case assumes that interconnectors between regions are unavailable. In this case:

(a) in exporting regions, generators are not dispatched, or are dispatched at a zero price, and

(b) in importing regions, consumers pay the assumed LRMC of generation that could be constructed in that region.

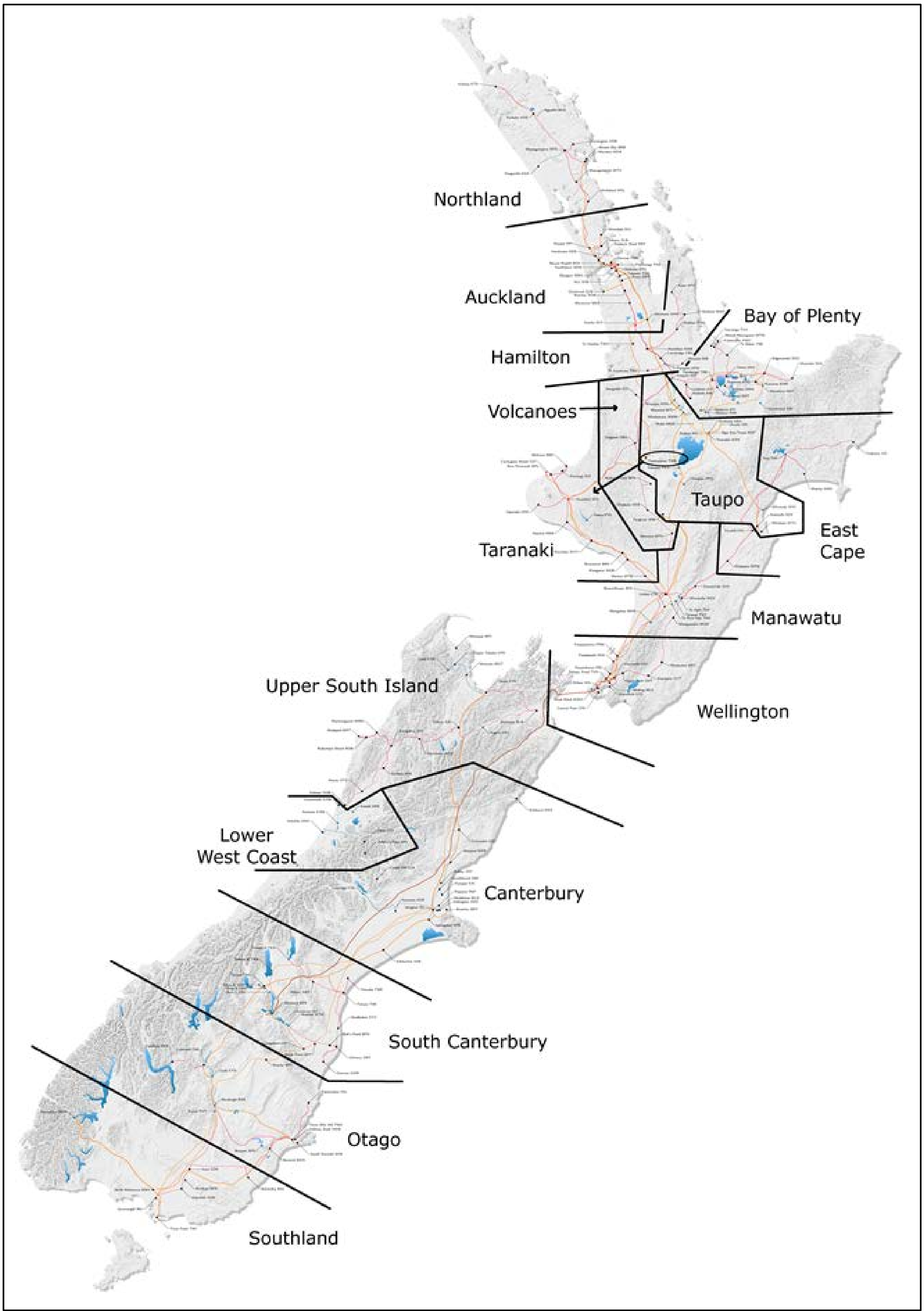
B.14 As in the less complex SPD method, benefits are calculated at each node – but now generation nodes in importing regions and load nodes in exporting regions are excluded from this calculation. Each party's generation or load quantity at each node is multiplied by the difference between the actual spot price and the counterfactual price to determine the benefit from the presence of the grid.

B.15 As in the less complex SPD method, each party's transmission charge is their share of total benefits multiplied by the revenue to be recovered under the TPM.

B.16 A key issue with this option would be determining the regions. One option would be to adopt the regions identified in the analysis on within island basis risk (WIBR). The reason why using the WIBR regions may be appropriate is that the basis for determining the WIBR regions is broadly the same as that required for transmission pricing purposes.

B.17 The regions used for applying this method are shown in Figure 25.

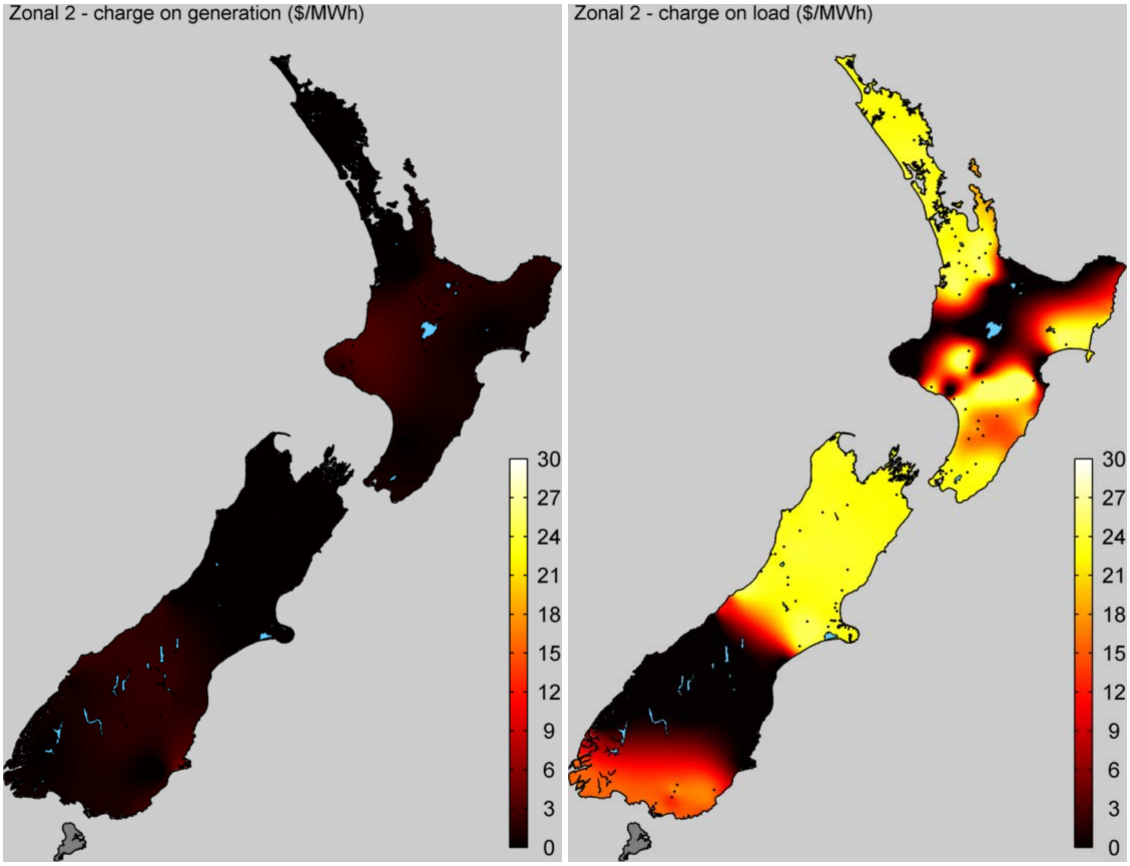
Figure 34: Regions for import- and export-benefits approach




Source: Electricity Authority

B.18 Charges that might result from the application of this method (depending on the parameters used) are shown in Figure 35.

**Figure 35: Charging rates under the import or export benefits method**

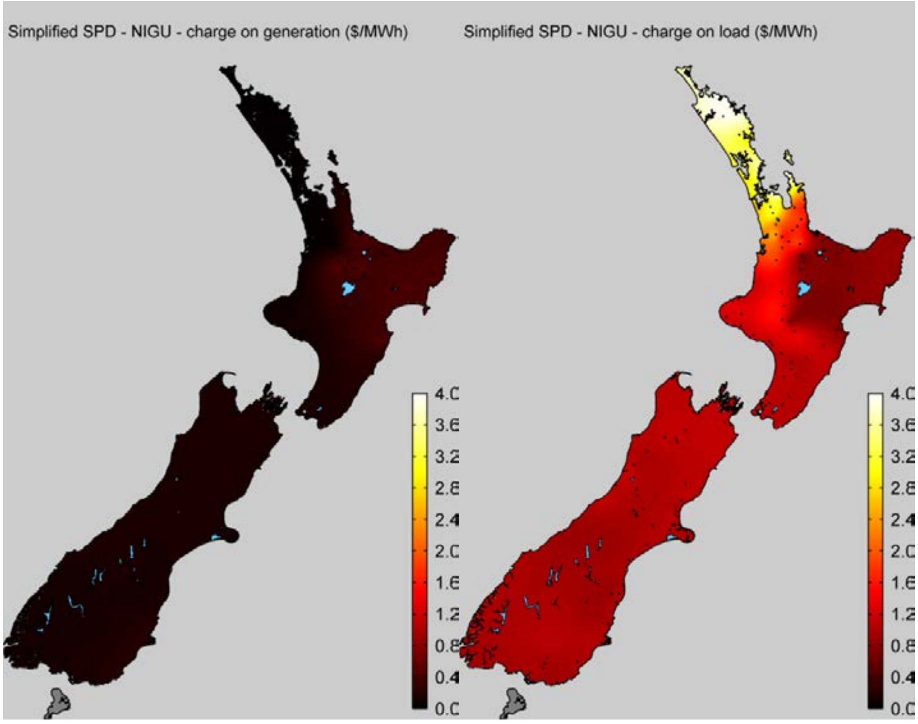



Source: Electricity Authority

B.19 This method is not preferred because it spreads the revenue requirement of each investment across all parties paying import- and export-based benefit charges, rather than recovering the cost from beneficiaries of that investment.

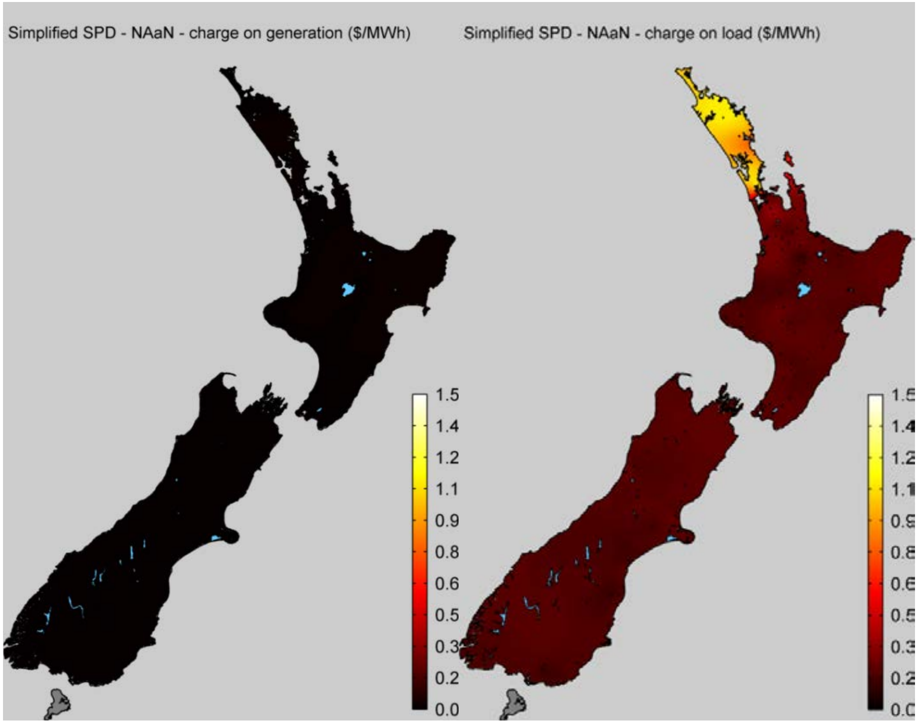
# Appendix C Modelling results - heat maps for simplified SPD method

**Figure 36: Simplified SPD charges for NIGU for 4 months**



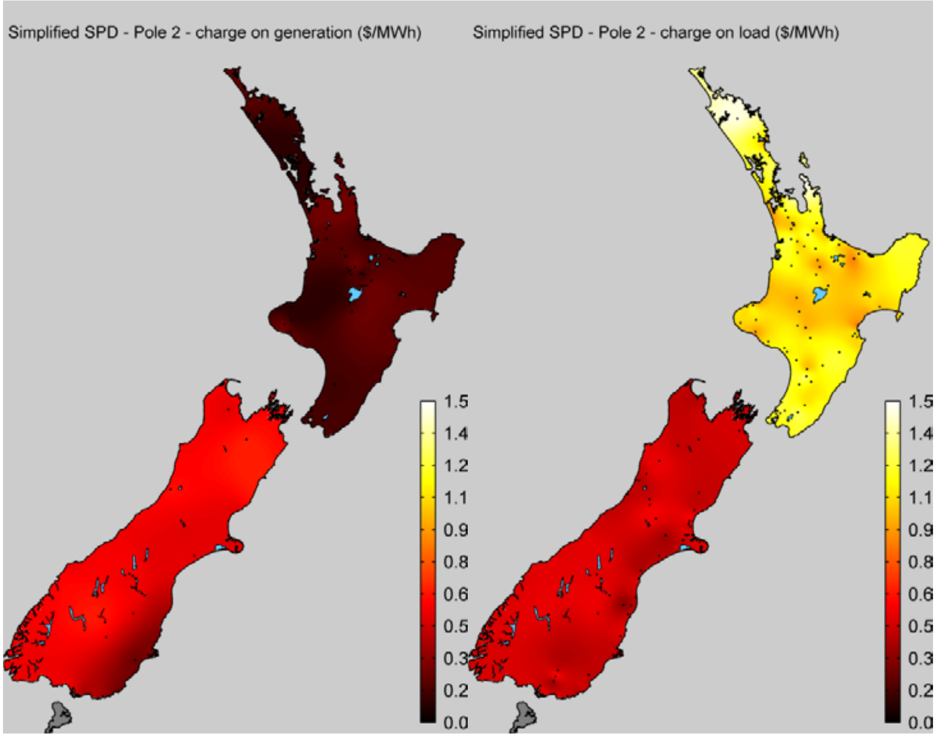

Source: Electricity Authority

**Figure 37: Simplified SPD charges for NAaN for 4 months**



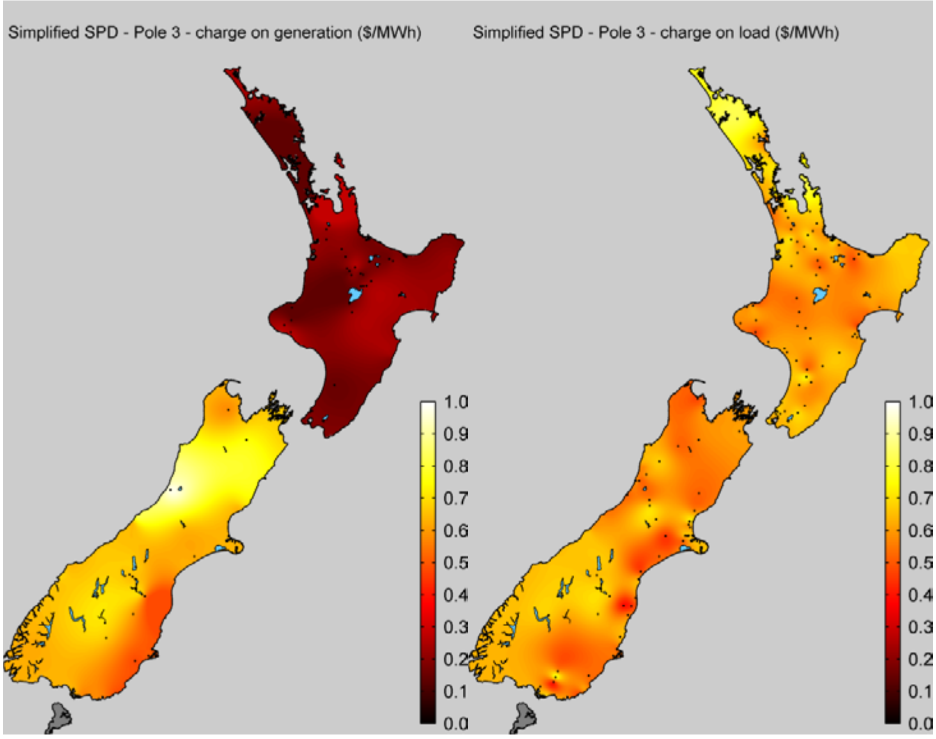

Source: Electricity Authority

## Figure 38: Simplified SPD charges for HVDC Pole 2 for 4 months



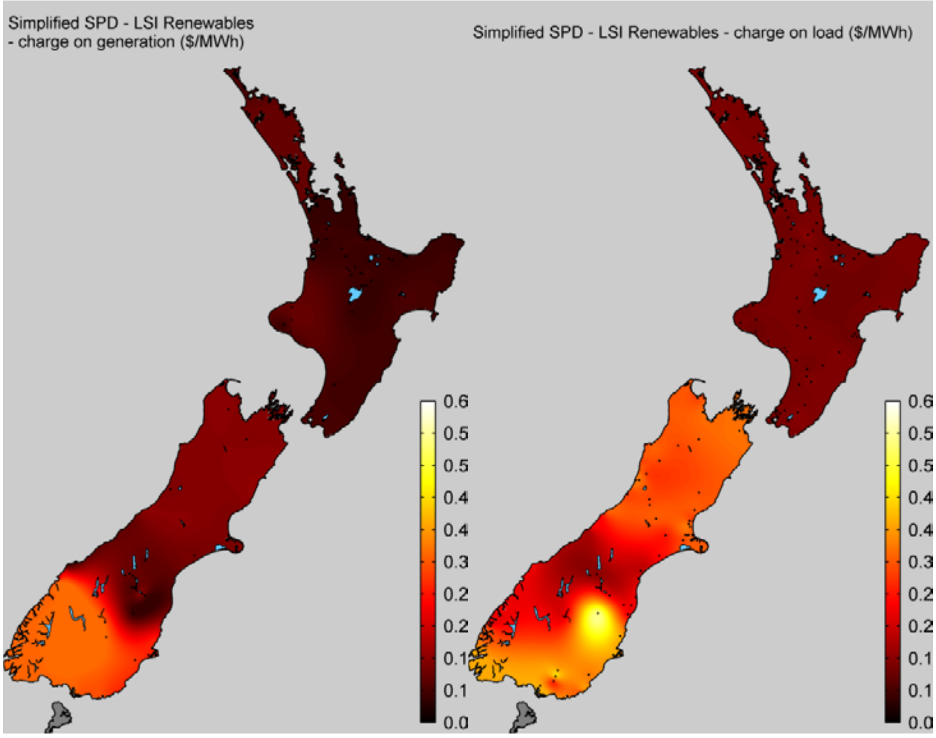

Source: Electricity Authority

## Figure 39: Simplified SPD charges for HVDC Pole 3 for 4 months



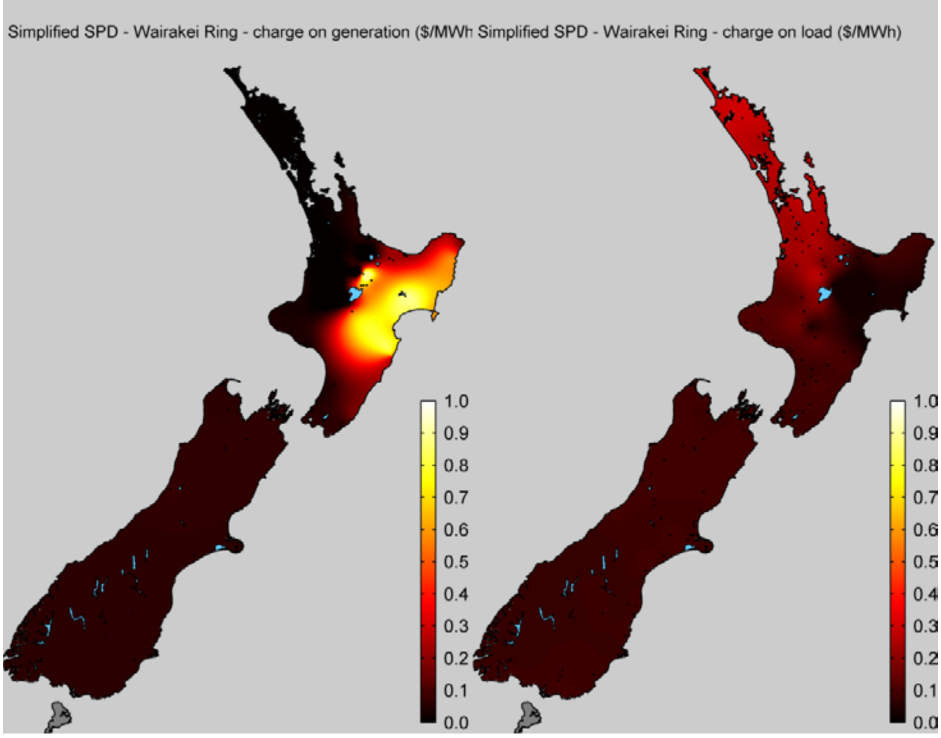

Source: Electricity Authority

## Figure 40: Simplified SPD charges for LSI Renewables for 4 months



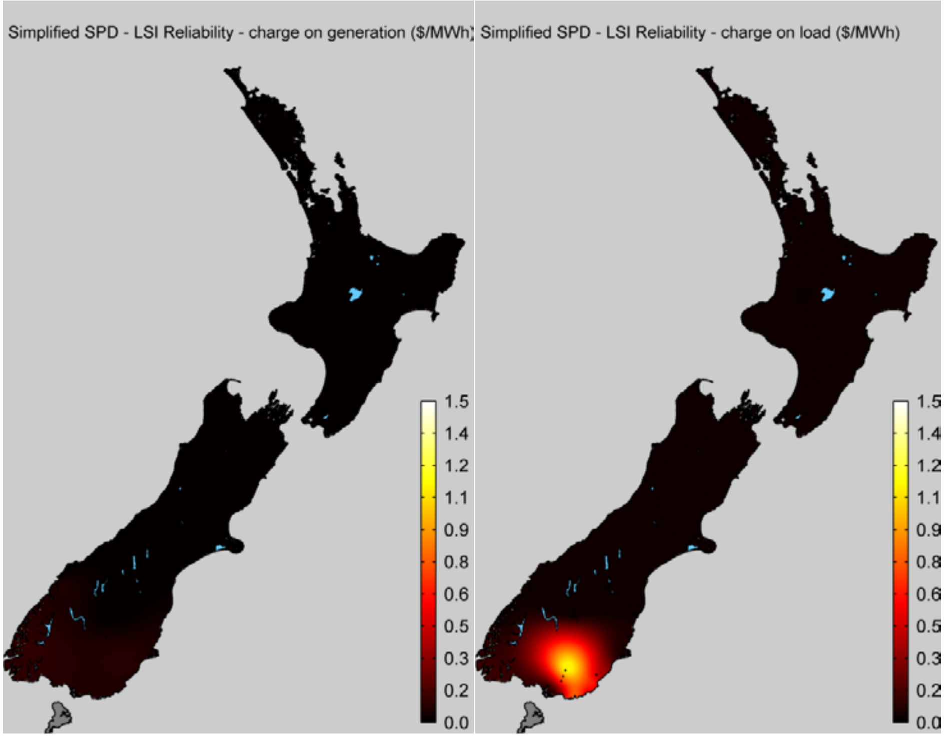

Source: Electricity Authority

## Figure 41: Simplified SPD charges for Wairakei Ring for 4 months



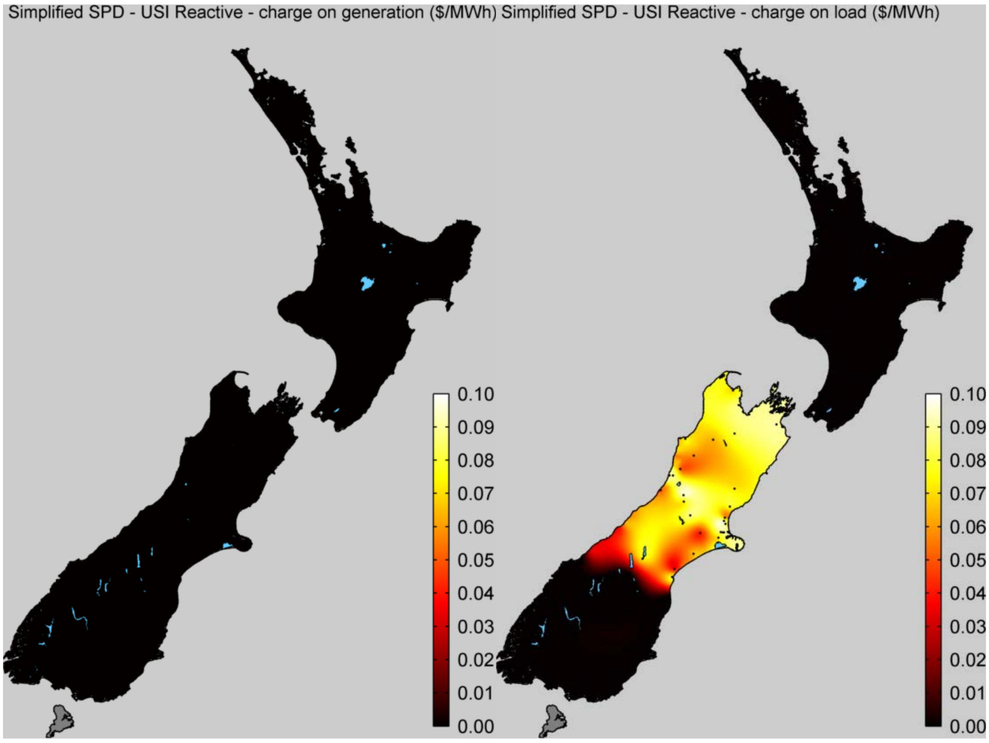

Source: Electricity Authority

## Figure 42: Simplified SPD charges for LSI Reliability for 4 months



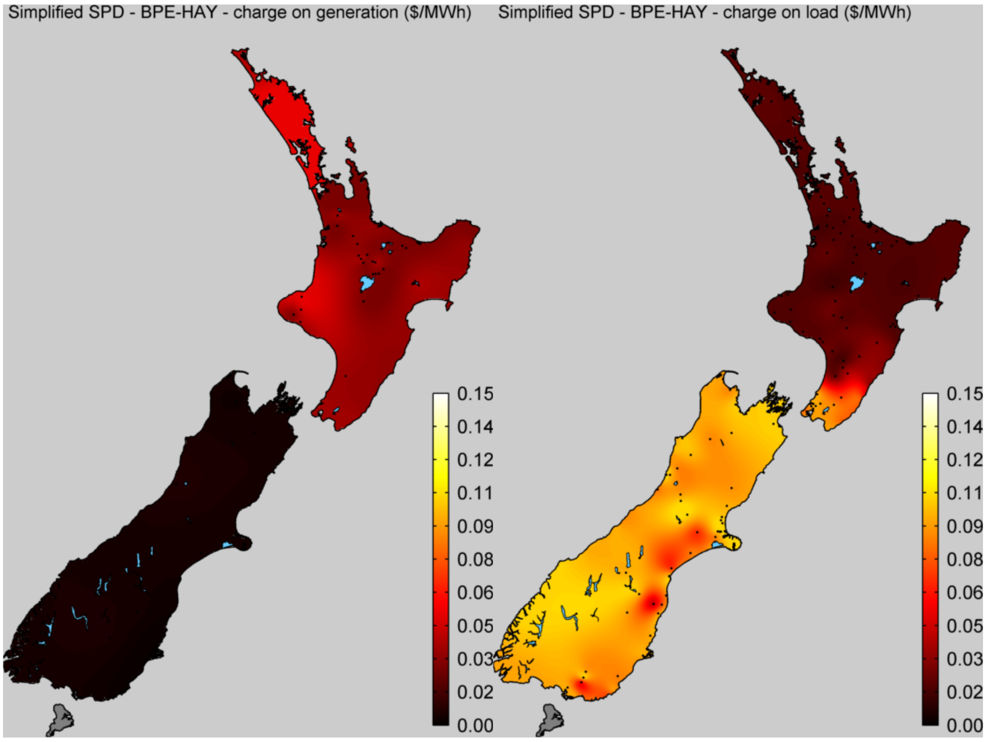

Source: Electricity Authority

## Figure 43: Simplified SPD charges for USI Reactive for 4 months



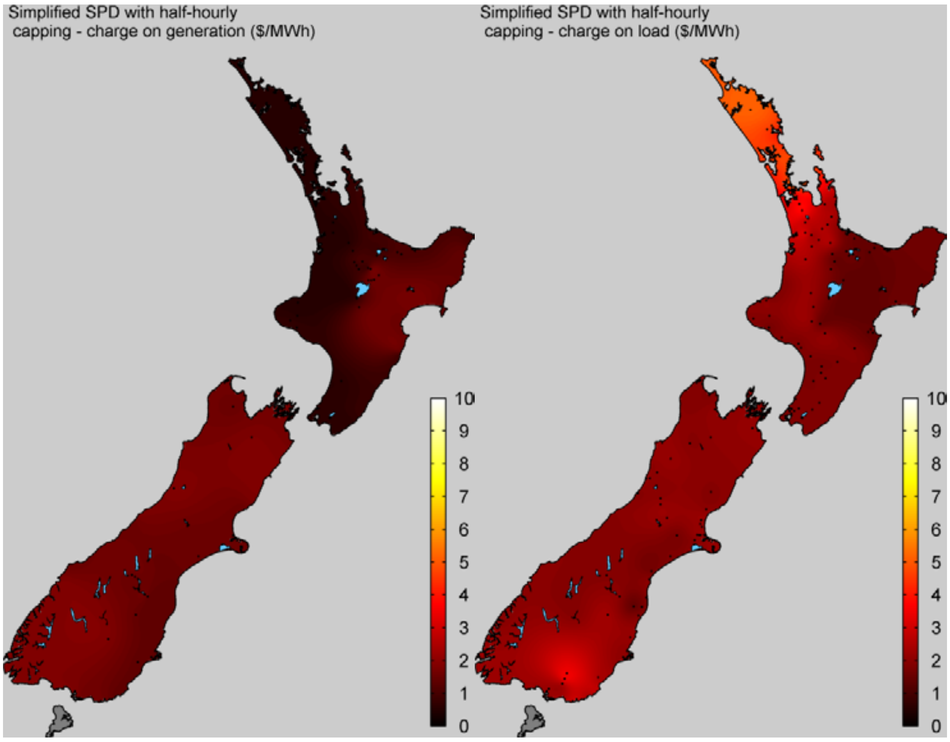

Source: Electricity Authority

## Figure 44: Simplified SPD charges for BPE-HAY for 4 months




Source: Electricity Authority

## Figure 45: SPD charges for generation and load using half-hourly capping (analogous to 2012 proposal) for 4 months




Source: Electricity Authority

# Appendix D Demand response at consumer nodes

D.1 The SPD method in the October 2012 issues paper assumed that consumers' consumption of electricity did not change in response to changes in prices, at least up to the point when electricity was not supplied. That is, the proposal assumed perfectly inelastic demand up to a price of $3000.

D.2 Some submitters considered that this assumption ignored the fact that some consumers, at least, curtail their demand in response to high prices.[68] They considered this resulted in an over-estimate of the benefit to consumers from transmission investments, and therefore excessive SPD charges.

D.3 The Authority investigated the response of consumers to changes in the wholesale market price for the period 2009 to 2012.

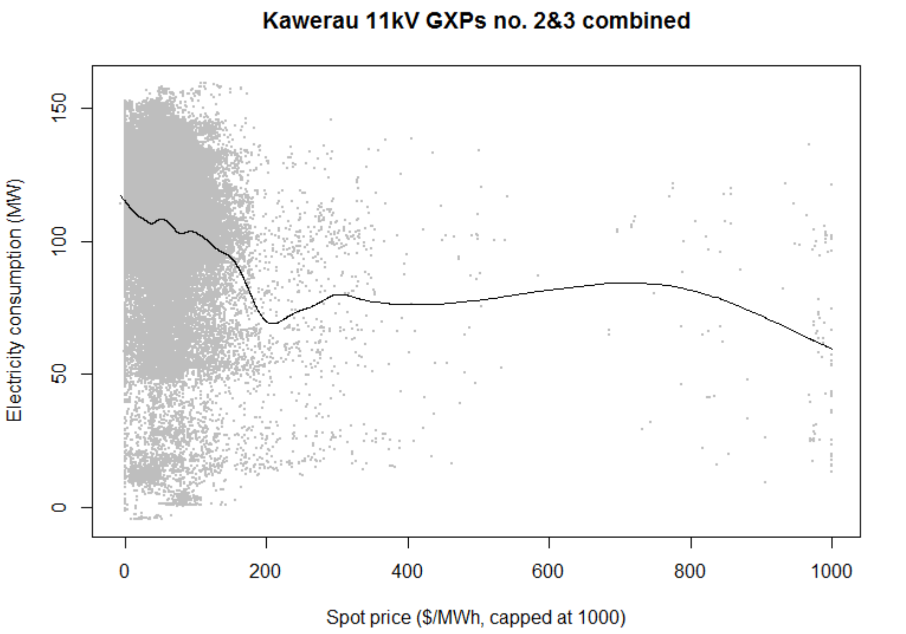
**Demand response at major consumer nodes**

D.4 The Authority's investigation identified that some large industrial consumers curtailed their demand for electricity at a wholesale market price of around $200/MWh but the extent of the response varied. The demand response of the large industrial consumers whose demand response was analysed is illustrated in Figure 46 to Figure 50.

D.5 However, not all large consumers changed their demand in response to high prices, e.g. Pacific Aluminium, as shown in Figure 50. This is likely to reflect the fact that the ability of industrial consumers to change their electricity demand in response to high prices is likely to vary depending on the industrial process.

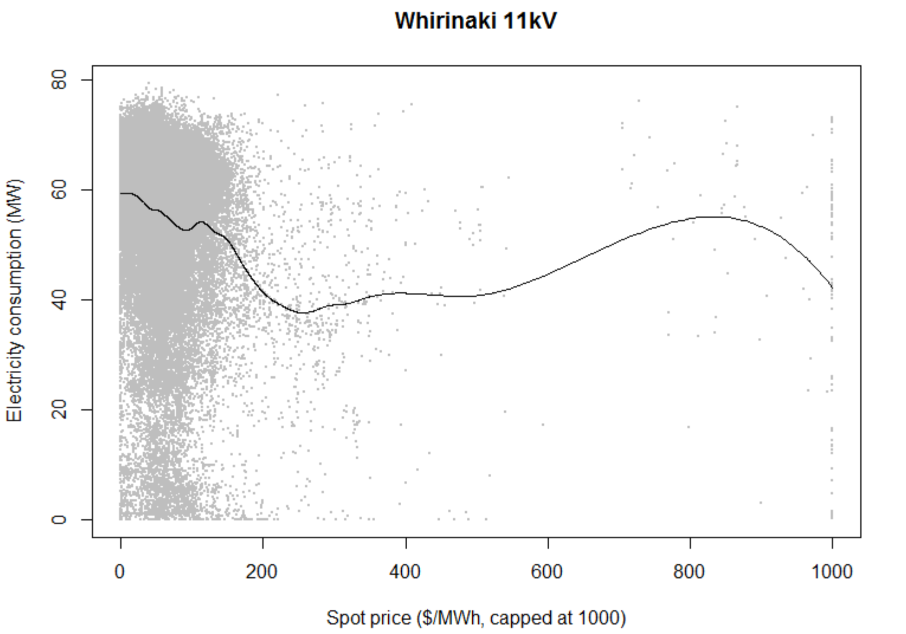
[68] MEUG submission on October 2012 issues paper, attachment NZIER report pages 20-21.

## Figure 46:[69] Relationship between electricity consumption and spot price at Kawerau




Source: Electricity Authority

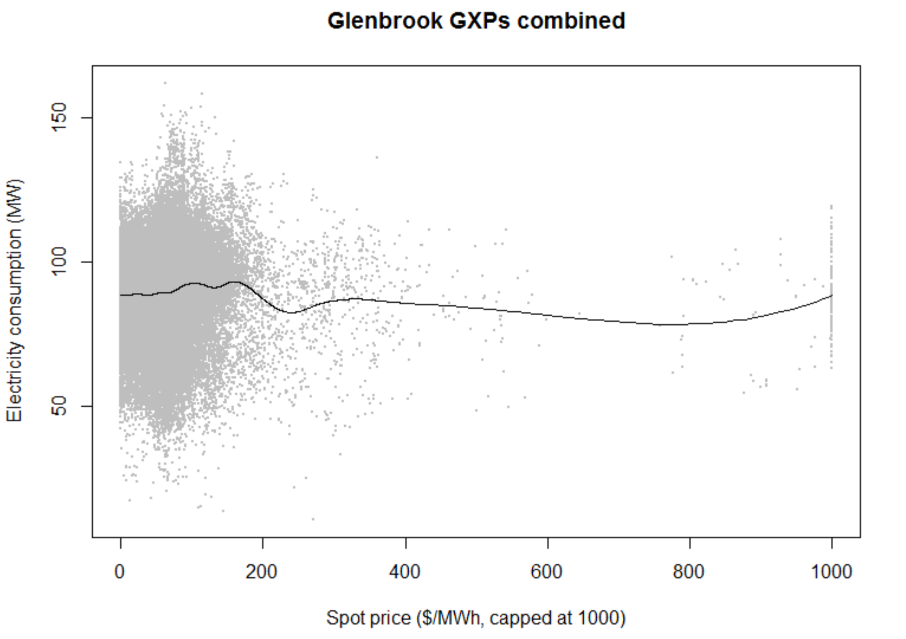
## Figure 47: Relationship between electricity consumption and spot price at Whirinaki




Source: Electricity Authority

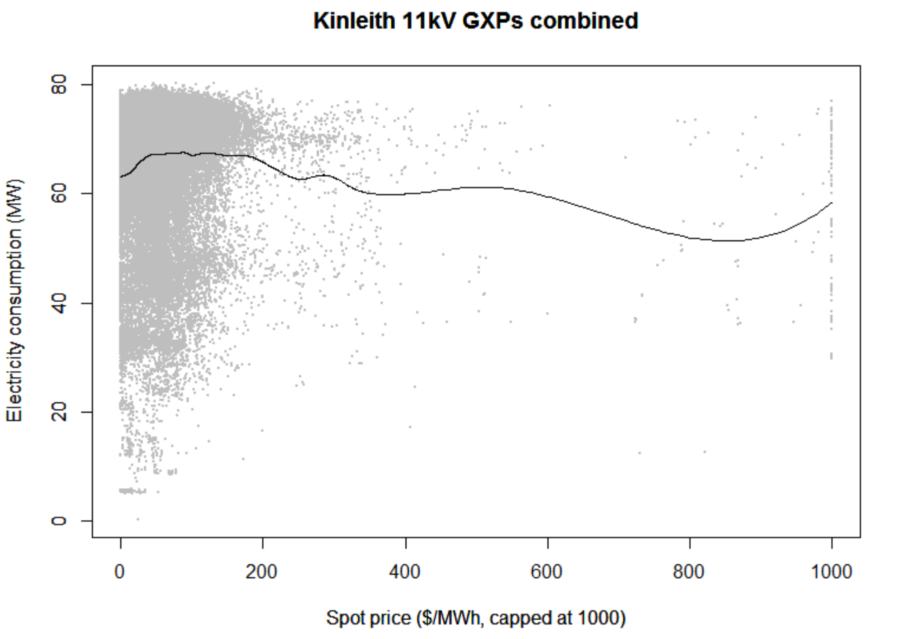
[69] Note there was a major change in demand by Norske Skog at Kawerau during the period 2009-12.

## Figure 48: Relationship between electricity consumption and spot price at Glenbrook



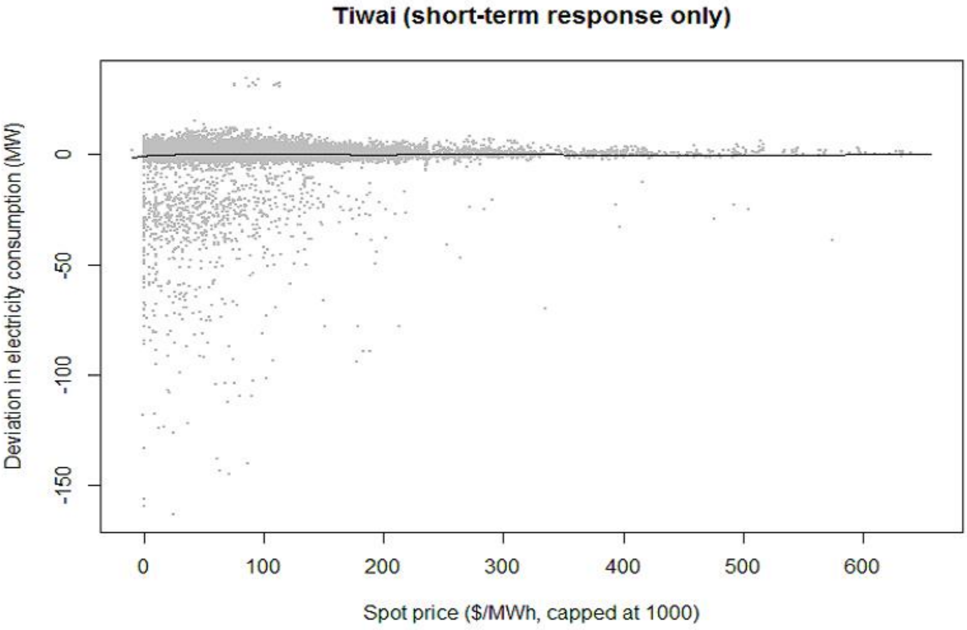

Source: Electricity Authority

## Figure 49: Relationship between electricity consumption and spot price at Kinleith




Source: Electricity Authority

**Figure 50: Relationship between deviation in electricity consumption and spot price at Tiwai**




Source: Electricity Authority

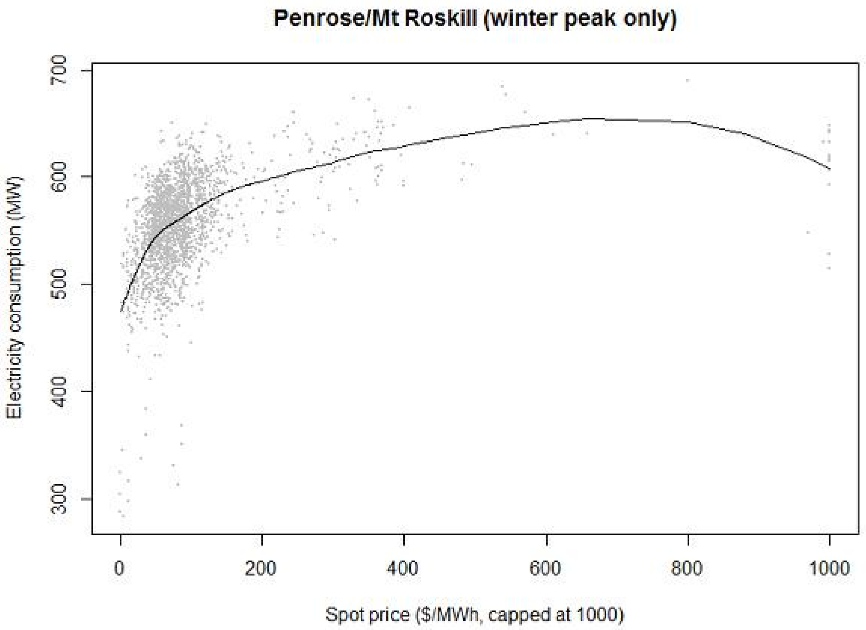
**Demand response at mass market nodes**

D.6 The Authority investigated whether there was any response by mass market demand to high prices during winter peaks. Winter peaks were chosen on the basis that to the extent mass market demand is sensitive to high prices this is likely to be greatest during periods that have a major impact on overall charges. This is likely to be the case with winter peaks as high marginal cost generation is likely to be required plus demand during these periods is likely be used to calculate the interconnection charge given it is calculated using regional coincident peak demand.

D.7 Figure 51 to Figure 54 show the demand response to the wholesale price during winter peaks for the Penrose/Mt Roskill, Islington/Papanui, Central Park and Kensington nodes. This shows that up to a price of between about $200 and $600/MWh demand actually *increases* as the wholesale price increases. This is, of course, the exact opposite of what would be expected as demand curves should have a slope like the demand curve, D, in Figure 32, which shows demand decreasing in response to increasing prices. The likely reason for the price responses shown in Figure 51 to Figure 54, at least up to about $200 to $600/MWh, is that the wholesale price is rising in response to increasing mass market demand as more expensive generation is needed to supply increasing demand. In other words, the price is rising in response to the demand rather than demand increasing in response to the price.

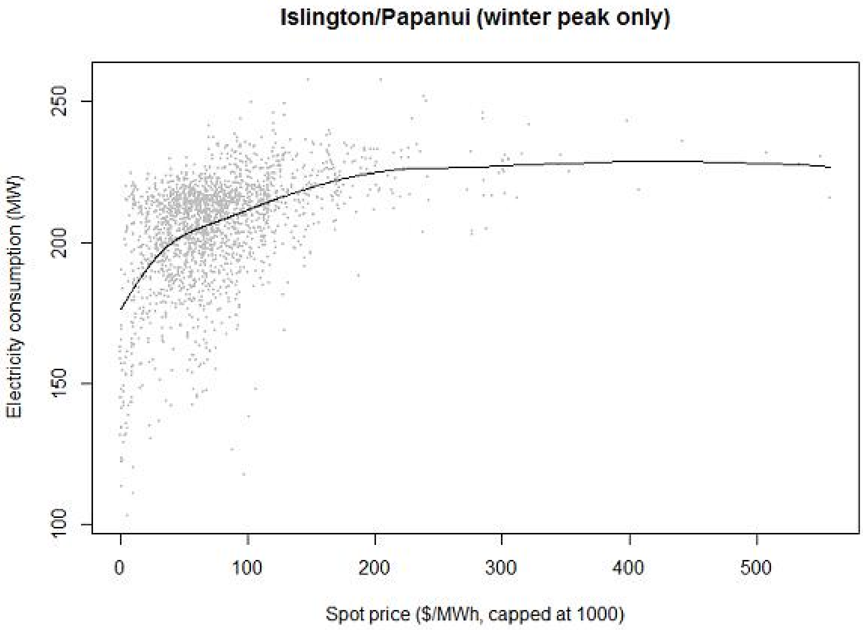
D.8 Figure 51 and Figure 54 show that at Penrose/Mt Roskill and Kensington demand falls once the price gets above about $800/MWh, and Figure 53 shows this also occurs at Central Park once the price gets above about $600/MWh. This may be demand responding to high prices. However, since all these nodes are in the North Island and this pattern is not seen at Islington/Papanui, as shown in Figure 5, there may be a similar explanation to the price response up to $200/MWh, such as a generator response to high prices during high demand. Alternatively, demand may be being managed to a capacity limit at these different nodes, e.g. about 220MW at Islington/Papanui, as shown in Figure 52, and about 170MW at Central Park, as shown in Figure 53.

**Figure 51: Demand response for winter peaks at Penrose/Mt Roskill**



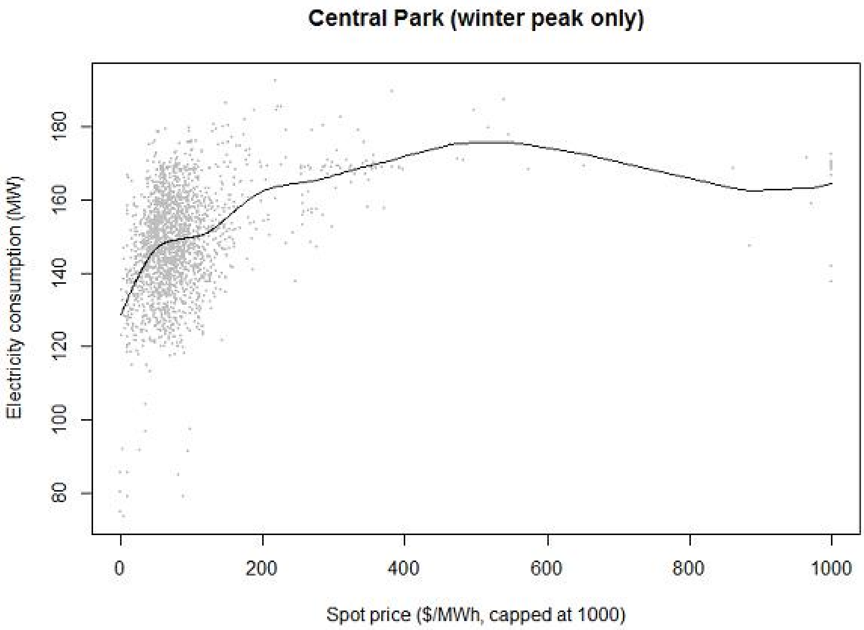

Source: Electricity Authority

## Figure 52: Demand response for winter peaks at Islington/Papanui



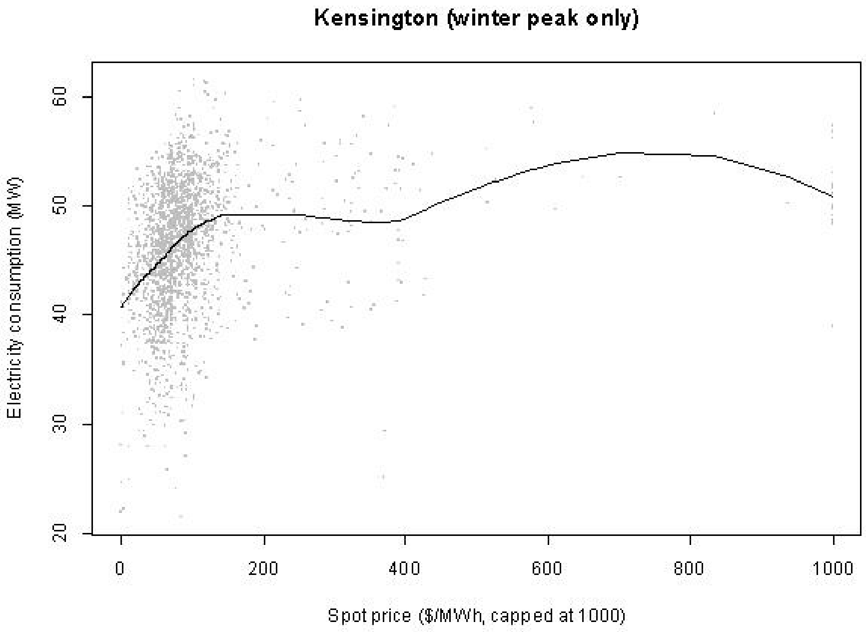

Source: Electricity Authority

## Figure 53: Demand response for winter peaks at Central Park




Source: Electricity Authority

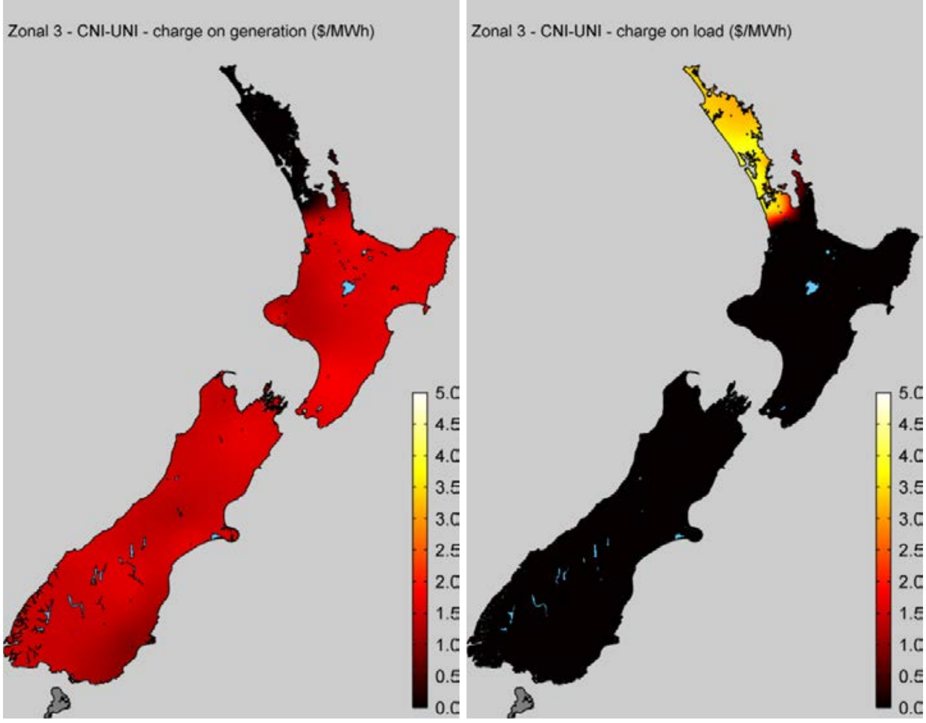
## Figure 54: Demand response for winter peaks at Kensington




Source: Electricity Authority

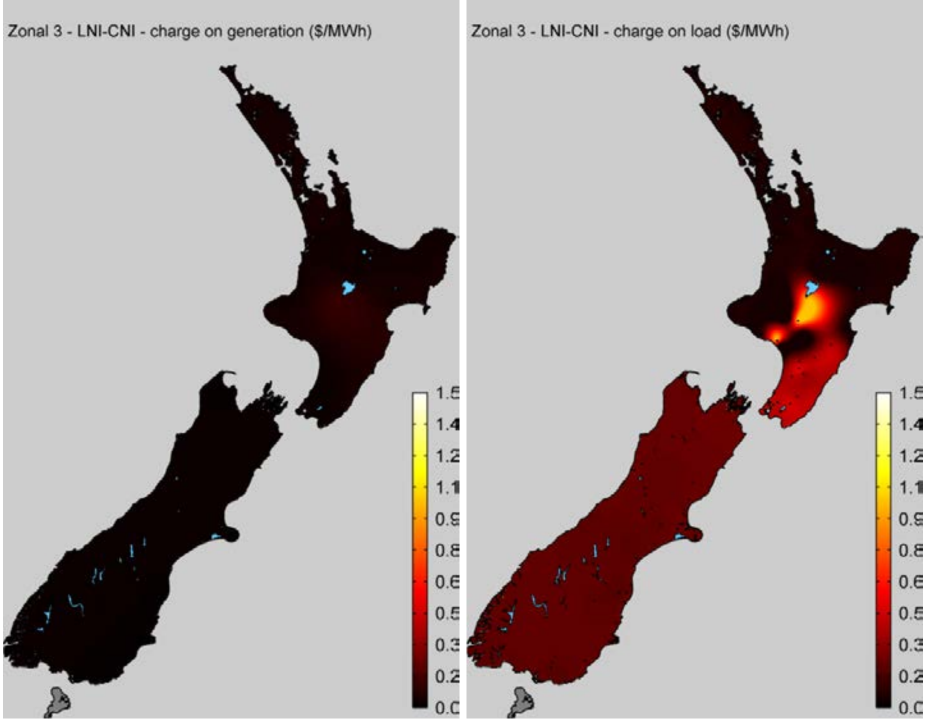
## Appendix E Interconnector charges for zonal SPD option

### Figure 55: Incidence of charges for CNI-UNI interconnector for 4 months



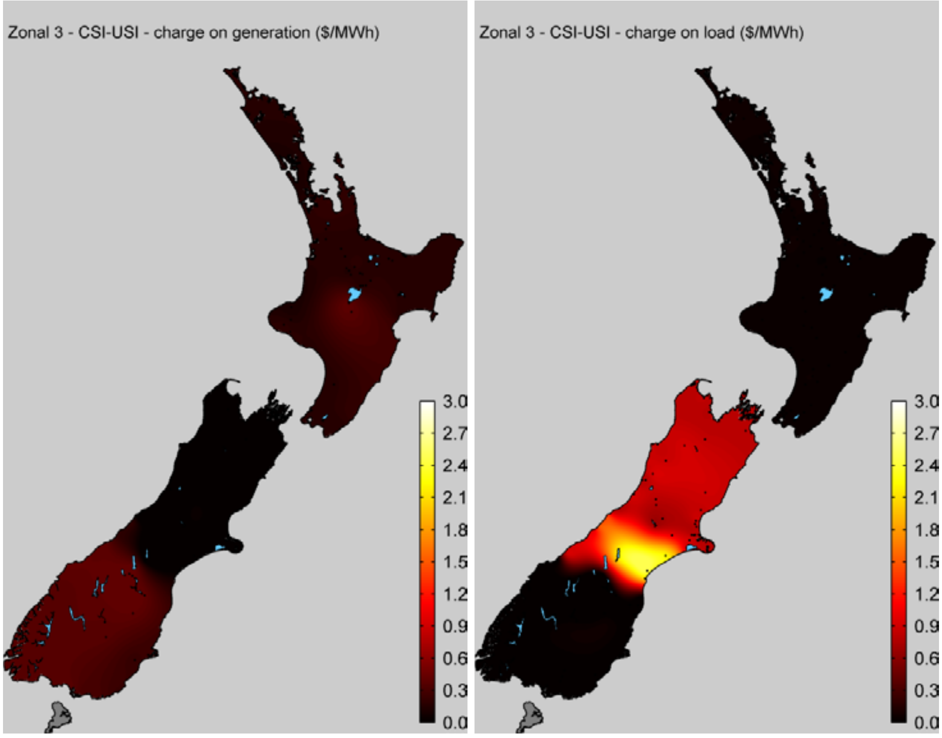

Source: Electricity Authority

### Figure 56: Incidence of charges for LNI-CNI interconnector for 4 months



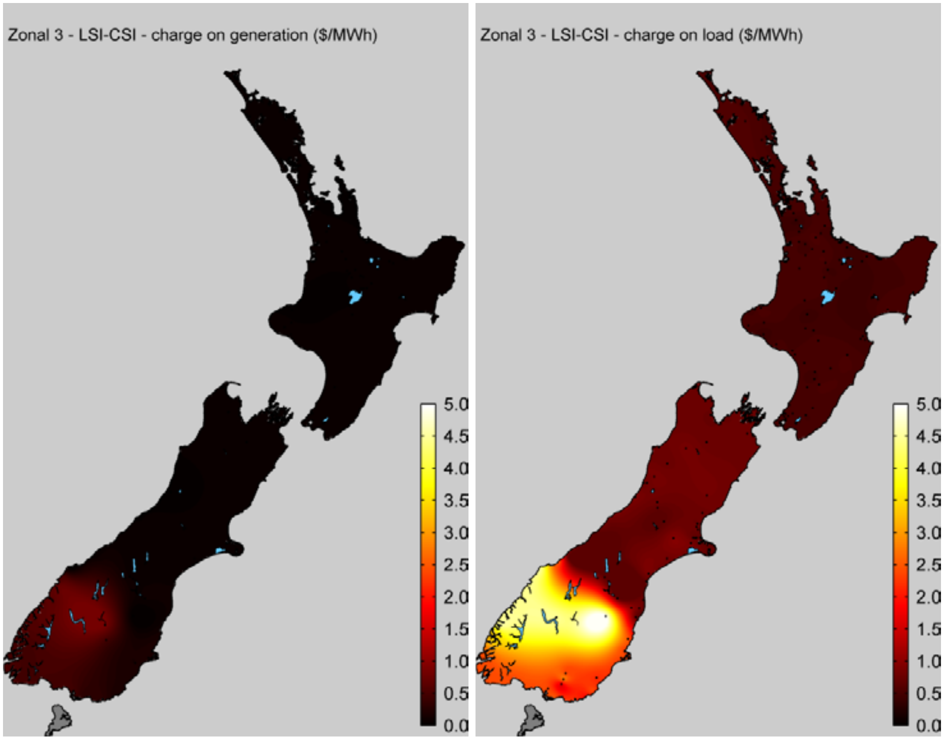

Source: Electricity Authority

## Figure 57: Incidence of charges for CSI-USI interconnector for 4 months



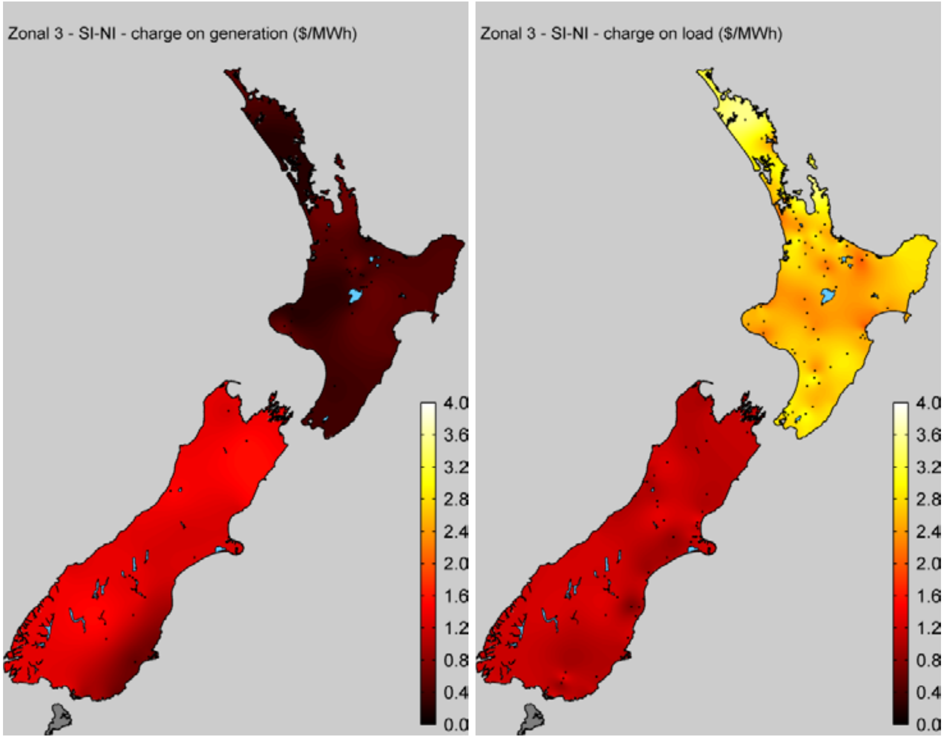

Source: Electricity Authority

## Figure 58: Incidence of charges for LSI-CSI interconnector for 4 months




Source: Electricity Authority

## Figure 59: Incidence of charges for SI-NI interconnector (HVDC) for 4 months

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Source: Electricity Authority

## Glossary of abbreviations and terms

| | |
|---|---|
| **Act** | Electricity Industry Act 2010 |
| **Authority** | Electricity Authority |
| **Code** | Electricity Industry Participation Code 2010 |
| **GWh** | Gigawatt hour |
| **GXP** | Grid exit point |
| **kWh** | Kilowatt hour |
| **MW** | Megawatt |
| **MWh** | Megawatt hour |
| **SO** | System Operator |