Transmission Pricing Methodology Review: TPM options working paper

Companion paper describing the detail of the deeper connection charge

June 2015

Market Design

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Contents

1 Introduction

1.1 The Electricity Authority (Authority) is reviewing the electricity transmission pricing methodology (the TPM review).

1.2 The Authority considers that there is potential for alternative options to the current TPM to 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.

1.3 The Authority has released an options working paper which assesses potential options to address the problems identified in relation to the TPM.[1]

1.4 Each of the options contained in the options working paper include a new component, namely a deeper connection charge. As the deeper connection charge is new and has not been discussed in previous consultation, the Authority has produced this companion paper to the options working paper to outline in further detail the proposed design of the deeper connection charge.

1.5 Other charge components considered in the options working paper include:

(a) loss and constraint excess (LCE) credits

(b) long-run marginal cost (LRMC) charges

(c) beneficiaries-pay (area-of-benefit (AoB) and scheduling, pricing and dispatch (SPD)) charges

(d) residual charges.

1.6 Versions of each of these have been proposed and/or discussed in previous TPM review consultations. The Authority has not therefore prepared a separate companion paper for any of these components.

1.7 This paper should be read in conjunction with the options working paper.

[1] Electricity Authority, Transmission Pricing Methodology Review: TPM options working paper, 16 June 2015.

2 What is the deeper connection charge?

Existing TPM connection charges to remain separate from deeper connection

2.1 The current connection charge is a 'deep' connection charge as it includes both:

(a) assets that provide a physical connection to the grid (which would be the only assets included in a 'shallow' connection definition) plus

(b) some assets beyond the point of physical connection that exist to physically connect parties' electrical assets to the grid.

2.2 The Authority considers the current connection charge to be a market-like charge.

2.3 The Authority proposes to retain the existing connection charge.

New deeper connection charge

2.4 While the Authority proposes to retain the existing connection charge, the Authority is considering adding a deeper connection charge. This would extend the concept of connection deeper into the grid to cover assets that are predominantly used by a small number of parties (generation and/or load). To distinguish this potential new charge from the existing connection charge, the potential new charge is referred to as a 'deeper connection' charge.

2.5 The Authority considers that charging via deeper connection where assets are used predominantly by a small number of parties, would act as a proxy for the likely charges negotiated under a multi-party investment agreement if the parties had to negotiate directly with Transpower for the provision of the assets. The Authority considers that the deeper connection charge is a market-like approach.

2.6 It is proposed that flow tracing would be used to identify assets that are predominantly used by only a small number of parties.

2.7 Flow tracing attributes the proportion of the total electricity flow on each transmission asset to individual loads and generators.

2.8 The higher the Herfindahl-Hirschman Index (HHI)[2] of shared flows by connected parties (load and/or generators) the more the asset resembles a connection asset. Conversely, the lower the HHI the more the asset resembles an interconnection asset. It is proposed that the deeper connection charge would be defined by the specification of the HHI (discussed below).

Priority of the deeper connection charge compared to other TPM charges

2.9 The deeper connection charge would not apply to an asset that is already treated as a connection asset.

2.10 The deeper connection charge would be applied before the LRMC, SPD, AoB and residual charges are applied. It is proposed the kvar charge would still apply to

[2] The HHI is a commonly accepted measure of market concentration. It is calculated by squaring the percentage market share (in this case load flow) of each market participant and adding these together, that is, $HHI = \sum_{i=1}^{N} s_i^2$, where s_i is the market (flow) share of firm i in the market (asset), and N is the number of firms. The HHI has a range between 0 (fully competitive market) and 10,000 (monopoly).

provide a price signal to exacerbators of the need for investment in static reactive support equipment. The SPD, AoB and residual charges would only apply where the deeper connection charge did not recover Transpower's revenue requirement in relation to an asset. The LRMC charge would be applied to provide a price signal about the costs of future investment in the grid beyond the coverage of the deeper connection charge.

3 Rationale for the deeper connection charge

3.1 The Authority considers that the current connection charges may not recover the full economic costs of parties connecting to the grid.

3.2 Current interconnection assets fit within a spectrum in which assets can be described as 'pure' connection assets, whose sole purpose is to connect specific parties (load and/or generators) to the grid at one end, and, at the other end, 'pure' interconnection assets which is common to or shared by all connected parties for transmission of electricity over the grid.

3.3 Within this spectrum there are assets which are currently defined as interconnection assets but which are predominantly only used by a small number of parties (load and/or generators). The Authority considers that these assets should be treated as connection assets, rather than interconnection assets, for pricing purposes.

Promotion of efficient investment

3.4 The current connection charge only covers *some* assets beyond the point of physical connection that exist to connect, or exist to predominantly connect, parties' electrical assets to the grid.

3.5 The deeper connection charge seeks to promote efficient investment by extending the definition of connection assets deeper into the grid, to cover all assets which are predominately used by a small number of parties. In principle, these assets could have been financed through commercial negotiation for transmission services. The deeper connection charge is therefore a market-like charge.

3.6 The deeper connection charge seeks to identify those situations in which, in the absence of a regulator, the parties involved could have otherwise been expected to come together and negotiate an efficient contract for investment. It would recover all costs that would be the subject of such a contract: costs of the investment, operation and maintenance in relation to the asset, and a contribution to the common costs of the asset provider.

3.7 Replicating charges that would be established through a commercial negotiation would incentivise participants to make decisions consistent with those they would make in a workably competitive market, which would promote efficient investment and operation. The rationale for the proposed design of the deeper connection charge is discussed in greater detail below.

3.8 In order to promote efficient investment, the deeper connection charge would need to approximate the cost parties would face if they negotiated with Transpower, or another party, for transmission services (or alternatives) in a workably competitive market. This would promote the potential for contractual arrangements with Transpower for the provision of transmission services (such as under a customer investment contract or CIC) and, potentially, arrangements with other transmission service providers (or alternative service providers), thus promoting contestability.

3.9 In a workably competitive market, assets that are in excess of requirements as a result of the exit or substantial reduction of demand of a major customer or customers (stranded assets) would likely be revalued and the prices for the asset adjusted accordingly. Other customers in the region (in the case of targeted charges) or all customers (in the case of smeared charges) would not be required to bear the costs of serving the exiting customer's demand. Although re-valuation of transmission assets is not a matter for the Authority to consider (as it is under the auspices of the Commerce Commission), the Authority is considering whether deeper connection charges should be reallocated in cases where a large customer exits. If deeper charges were reallocated, the stranded costs that would have otherwise have been met by the customer that had exited would need to be recovered through the residual charge. This is because the TPM must be designed so that Transpower fully recovers its revenue. Conversely, the Authority is considering whether charges should be adjusted for situations where a large customer connects. The Authority is interested in submissions as to whether deeper connection charges should be adjusted to account for entry and exit of large customers and, if so, how this should be done.

4 Proposed design of the deeper connection charge

4.1 The proposed methodology for identifying deeper connection assets and for calculating and allocating deeper connection charges is described below.

Treatment of existing and new investments

4.2 The options working paper considers whether the proposed new charges, including the deeper connection charges, should apply to all eligible existing and new investments (Application A), or to new investments only (Application B).[3]

4.3 The Authority is considering adoption of Application B as a way of mitigating potential large price changes. The options working paper also discusses potential transition arrangements. The Authority would welcome comments on whether the new charges should only apply to new assets, and whether some form of transition arrangement should be adopted.

High level description of the calculation

4.4 Deeper connection assets would be assets mainly used by a small number of users. It is proposed that flow tracing would be used to identify such assets. Flow tracing attributes the proportion of the total electricity flow on each transmission asset to individual loads and generators.[4] It is proposed that deeper connection assets would be defined as those with a high HHI of shared flows.

4.5 The Authority has considered applying the deeper connection approach across the grid and not restricting it to assets where there is just a small number of users. However, the prospect of large numbers of users reaching agreement for an investment or upgrade is low because of the high transactions costs involved in such negotiations. Applying a deeper connection charge to such situations would not be consistent with the Authority's decision-making and economic framework[5] because the resulting charge could not be considered market-like.

4.6 To accommodate changes in the electricity market it is proposed that the charge would be calculated on a five-yearly cycle.[6] This would result in a schedule of deeper connection assets and parties subject to deeper connection charges for these assets.

4.7 The Authority considers that a five-yearly calculation would be sufficiently dynamic to adapt to changing patterns of grid use. It would therefore be well targeted and thus promote investment efficiency, while also being sufficiently stable to disincentivise inefficient operational behaviour intended to avoid the charge. The HHI for each transmission asset (excluding current connection assets) would be

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3 In the options working paper Section 11, the Authority sets out potential applications of any proposed changes.

4 For further detail on flow tracing see the description in the following paper by the Electricity Commission on the use of flow tracing for transmission pricing, 18 June 2010, available at: https://www.ea.govt.nz/dmsdocument/7123.

5 Electricity Authority, Decision-making and economic framework for transmission pricing methodology, Decisions and reasons, 7 May 2012, available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/development/economic-framework-decision-making/

6 Some updates might be necessary between five-yearly recalculations, if only to calculate charges for new assets.

measured on a backward-looking basis, based on grid usage in the last five years. The five year period would help address potential charging volatility, that is, from assets fluctuating between interconnection and deeper connection.

4.8 Alternatively, the HHI could be calculated annually but with a minimum threshold of change in flow shares before the allocation would be revised.

Load and generation included

4.9 There are two HHIs for every asset – the supply side HHI and the demand side HHI. The former can be used to determine sharing by generators only and the latter for load only. The HHI can typically only be high near to loads or injections, before there has been meshing and loops of lines. However, loops with strong through-flows can retain the high HHI if they are between load aggregations and generation.

4.10 An asset can be identified as being deeper connection used by generators, deeper connection used by loads, both or neither. The asset would be deemed to be used by generators if its supply-side HHI is above a specific threshold, and by loads if its demand-side HHI is above a specific threshold.

Selection of HHI threshold

4.11 The intended purpose of the HHI calculation is not as a measure of 'benefit' per se (beyond the extent to which usage is a proxy for benefit) but, rather, an estimate of the likelihood of several parties contracting for provision of the assets if a regulatory backstop were not available for investment approval. The likelihood of agreement to an investment would, though, depend on whether the affected parties would receive net benefits from the investment.

4.12 It is proposed that an HHI threshold of 5,000 would be used for each of load and generation to identify assets that would be treated as deeper connection.[7] This is the HHI for the equivalent of two firms sharing equally in the flows for an asset. Such a threshold would limit the coverage of the charge to only assets used for the most part by either a very few customers or almost entirely a single customer.

4.13 A lower HHI threshold could potentially be used to identify deeper connection assets. For example, if it were considered that three equal sized parties ought to be able to reach agreement on an investment, this implies an HHI threshold of 3,333. However, agreement would have to be reached between the connecting parties and Transpower as well, that is, four parties in this example. Accordingly, the Authority is proposing the higher threshold of HHI=5,000 as the likelihood of agreement with fewer parties is much higher.

4.14 It is proposed that the load parties subject to the deeper connection charge would be the same parties subject to the current connection charge, that is, electricity distribution businesses (EDBs) and direct connect customers. The generation parties subject to the deeper connection charge would be grid-connected generators.

4.15 Under the proposal, assets with an HHI exceeding the threshold would be deemed to be deeper connection assets, and charges would be allocated to all parties identified as sharing the use of the asset. If the assets needed to be upgraded (for

[7] The Authority considers it is appropriate for consistency to applyi the same HHI for load and generation.

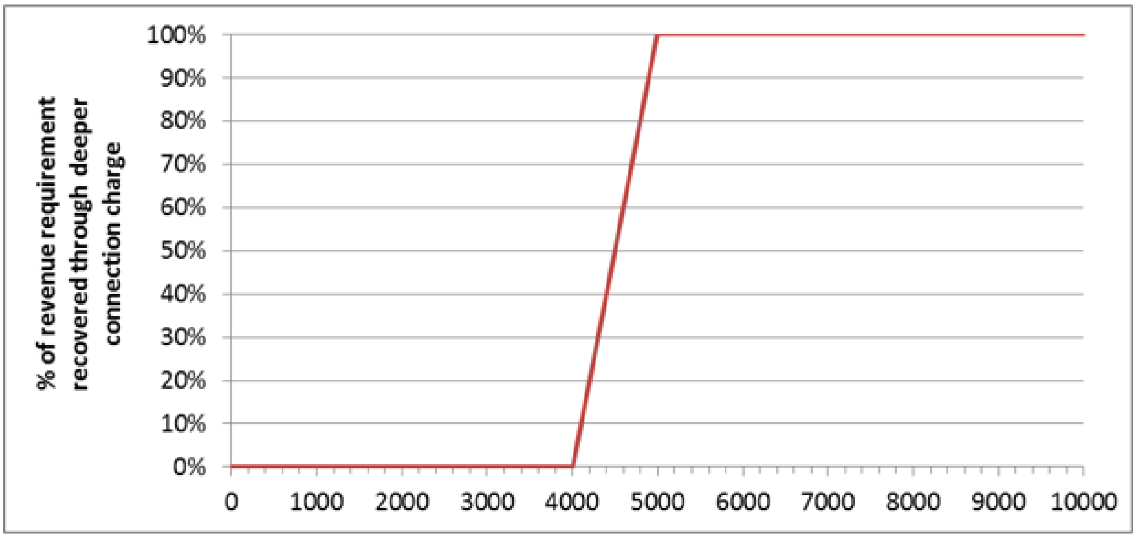
example, as indicated under a grid reliability report published under clause 12.76 of the Code), those are the parties that would pay for the upgrade of the asset.[8]

Graduated cut-off

4.16 The Authority proposes to apply a 'graduated cut-off' of between HHI=4,000 and HHI=5,000, rather than a 'hard cut-off' at HHI=5,000. A graduated cut-off would mitigate any potential charging volatility, where assets fluctuate between HHIs greater and less than 5,000. A graduated cut-off would also dilute the incentive for parties to inefficiently change their behaviour so as to reduce the HHI of an asset below the HHI=5,000 threshold.

4.17 Under the graduated cut-off, an asset with HHI=4,000 would be classed as interconnection, with HHI=5,000 or above being classed as deeper connection, and with HHI=4,500 being classed as a 50-50 mix of the two, and so on. This is illustrated in Figure 1.

Figure 1: Illustration of graduated cut-off for the deeper connection charge, with cut-off between HHI=4,000 and HHI=5,000



4.18 The Authority has undertaken modelling which indicates there would be little volatility from year to year in the classification of interconnection assets as 'deeper connection' or 'true interconnection'. In large part, this is due to the use of a 'graduated cut-off' from HHI = 4,000 to 5,000.[9]

4.19 To address incentives for demerging (that is, splitting into two or more entities or by sale to another party) in order to achieve a lower HHI, the Authority proposes to calculate HHIs for demerged parties as if they were a single entity. See footnote 10 for further details.

[8] To aid submitters' understanding of deeper connection charge calculations, examples are provided in Appendix B.

[9] Refer to Appendix C for details of the Authority's assessment of the stability of the deeper connection charge.

HVDC link exclusion

4.20 The Authority is not proposing that the deeper connection charge would apply to the HVDC link, even if it met one or both of the HHI thresholds. This is because treating the HVDC link as deeper connection would be inconsistent with the intention of the deeper connection charge, which is to extend the effective definition of connection deeper into the grid. The HVDC link is not an asset required to connect a party to the grid. Rather, it is an asset that is used to connect the North Island and South Island alternating current (AC) grids.

Allocation methodology

4.21 An allocator would be required for determining the share of charges for assets subject to the deeper connection charge. Allocation of the charge among parties would need to strike a balance between being effectively targeted to promote efficient investment while being as non-distortionary as possible to promote efficient operation.

4.22 The Authority considered several allocation options for deeper connection which are examined below.

4.23 Option 1 – Allocate according to flow shares.

(a) Practicability: The option is practicable as it uses information available through the flow trace.

(b) Potential incentive effects:

(i) This option would promote efficient investment because it would result in a charge that is targeted to customers' use of the asset. However, because peak demand and injection drive investment, allocating on flow shares only partially targets the drivers of investment.

(ii) The method could incentivise parties to change their operation or investment decisions in order to reduce their flow share.

(iii) The method may incentivise parties to split into multiple organisations, so as to reduce the HHI for new investments below the threshold. If this is considered to be more than a hypothetical concern, the design details of the charge would need to include provisions to address this issue, for example, by calculating HHIs for related entities as if they were a single entity.[10]

(iv) Under flow share allocation, peak or congestion charging on congested assets should be reasonably straightforward to introduce. For example, once an asset is deemed to be congested (by an automatic congestion trigger), the flow share allocation could be changed to a peak or congestion allocation.

4.24 Option 2 – Allocate according to anytime maximum injection/demand (AMI/AMD) of nodes that are 'connected by' the asset.

(a) Practicability: This could be done by:

[10] For example, related parties could be identified using a similar approach to that under the Commerce Act, where such parties are referred to as "interconnected bodies corporate".

(i) identifying the load and/or generation nodes that are deemed to be ‘connected by’ the asset, which are the nodes whose average flow share for the asset (over an extended period) exceeds a specified threshold.[11]

(ii) allocating deeper connection charges with respect to the asset in proportion to the AMD of ‘connected’ load nodes and the AMI of ‘connected’ generation nodes.

(b) This option (AMI/AMD at the connection location) is consistent with the allocation treatment under the current connection charge.

(c) Potential incentive effects:

(i) This option would promote efficient investment as it would result in a highly targeted charge that reflects a possible allocation of charges that would occur in a market and would adapt to changes in grid use. Given that the allocation is based on grid use, the method could incentivise inefficient avoidance of charges.

(ii) AMD or AMI provides a peak avoidance signal regardless of whether an asset is congested. Accordingly, it may promote inefficient operation.

(iii) AMD or AMI is a partial proxy for a capacity charge but, as it is still based on grid use, the method could incentivise parties to reduce the AMI/AMD of generators/loads subject to the deeper connection charge.

(v) The method may incentivise parties to split into multiple organisations, so as to reduce the HHI for new investments below the cut-off. This would be dealt with in the same way as for allocation according to flow shares.

4.25 Option 3 – Each party pays according to the thermal capacity of the connection assets of parties subject to the deeper connection charge at relevant connection locations.

(a) Practicability: The Authority considers that allocation could be based on connection transformer capacity or circuit breaker capacity[12], although detailed investigation is required to confirm that the option is practicable.

(b) Potential incentive effects:

(i) This option would promote efficient investment as a party’s share of a deeper connection charge would be directly related to the capacity of transmission services the party would be able to obtain from the deeper connection asset.

(ii) This option could promote inefficient downsizing because existing parties with excess thermal capacity would be incentivised to reduce their capacity to avoid the charge.

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[11] In this paper, the threshold has been modelled as 3 percent of AMD for load nodes and 3 percent of AMI for generation nodes. This threshold excludes nodes that use the asset ‘lightly’.

[12] The Authority understands that such an approach is taken in France. In particular, customers may elect the capacity of the circuit breaker at their point of connection and are charged according to their elected capacity.

(iii) This option would promote efficient operation as parties' operation would not affect their deeper connection charge.

4.26 Option 4 – An allocation based on MWh injection/offtake at nodes that are deemed to be connected by the asset.

(a) Practicability: The option should be relatively simple to implement.

(b) Potential incentive effects:

(i) This option would partially promote efficient investment because a MWh charge is highly targeted to parties' use. However since the capacity of deeper connection assets is driven by peak utilisation, an allocation mechanism that provides a peak signal would better promote efficient investment, particularly where assets become, or are becoming, congested.

(ii) This option may affect efficient operation as generators may alter their offers to reflect the additional cost they would incur from the charge.

(iii) The option does not provide a peak avoidance signal, although it should be reasonably straightforward to move to a congestion or peak-based charge once an asset approaches congestion.

(iv) It may be seen as a reasonable proxy for capacity although the option may incentivise some parties to reduce their injection or offtake to avoid the charge. The option may also incentivise directly connected consumers to invest in distributed generation to avoid the charge.

(v) The option is unlikely to incentivise inefficient avoidance of peaks because the charge is based on every MWh.

4.27 Option 5 – An allocation based on a number of ICPs for charges to mass-market load at nodes that are deemed to be connected by the asset (applicable for EDBs only).

(a) Practicability: The option should be relatively straightforward to implement.

(b) Potential incentive effects:

(i) This option is reasonably well targeted as the number of installation control points (ICPs) is a proxy for a customer's demand for transmission services.

(ii) The option does not provide a peak or congestion signal, although it should be reasonably straightforward to move to a congestion or peak-based charge once an asset approaches congestion.

(iii) The option is relatively non-distortionary as parties would have a limited ability to modify their behaviour to avoid the charge except by changing the number of ICPs at which they consume transmission services.

4.28 Option 6 – An initial allocation to mass-market load, direct connects and generation at nodes that are 'connected by' the asset based on MWh of offtake and injection, and then allocating charges as follows:

(i) a per ICP charge for mass-market load, with the rate depending on the metering category code of the ICP

(ii) a $/MWh or transformer (or circuit breaker) capacity charge for generators and direct connects.

(b) Practicability: The option should be relatively simple to implement.

(c) Potential incentive effects:

(i) While generators generally have additional transformer capacity, as the initial allocation to generators as a group is through a MWh charge, transformer (or circuit breaker) capacity is only used to divide the charge among the generators. This should limit the extent to which charging generators according to transformer capacity results in underinvestment in this capacity. This would also be the case for direct connect consumers.

(ii) This option would promote efficient investment because allocating charges on a MWh basis ensures the charge would be highly targeted to parties that create the requirement for deeper connection assets.

(iii) The option does not provide a signal to avoid peaks, although it should be reasonably straightforward to move to a congestion or peak-based charge once an asset approaches congestion.

(iv) The option is unlikely to incentivise inefficient peak avoidance because the charge is allocated among parties on a MWh basis but charged on a capacity basis.

4.29 The Authority is continuing to consider the relative benefits of the allocation options listed above. The Authority welcomes submitter views on which of the options would best ensure the allocation mechanism is well targeted and non-distortionary.

4.30 For the modelling of the charge in this paper the Authority employed option 2 - allocation based on AMI/AMD at the connection locations that are deemed to be ‘connected by’ the asset.

4.31 The Authority also seeks submitter views on whether the allocation mechanism for the deeper connection charge should incorporate a signal about the cost of impending future investment. One approach would be to automatically adjust to a peak or congestion charge when congestion had exceeded a pre-set threshold that indicated an investment signal is required. While this may introduce additional complexity, it could promote efficient deferral of transmission investment.

5 Modelling of the deeper connection charge

5.1 The Authority has modelled the deeper connection charge.[13]

5.2 For the purpose of this analysis, the Authority has carried out flow traces based on expected grid usage in the 2017-19 scenario. An expected (forward-looking) scenario rather than a backward-looking scenario is used because this provides a more accurate reflection of likely future charges. In practice, flow traces would be carried out on a backward-looking basis, based on grid usage in the last five years.

5.3 The HHI of each asset is calculated based on shared flows on that asset, for each half-hour aggregated over the three-year period of the scenario.

5.4 For assets with a load HHI or generation HHI over 4,000, nodes that are ‘connected by’ the asset are identified. These are:

(a) the load nodes whose mean flow share for the asset is at least 3 percent[14] of their AMD, if the load HHI is over 4,000

(b) the generation nodes whose mean flow share for the asset is at least 3 percent of their AMI, if the generation HHI is over 4,000.

5.5 Charges with respect to the asset are allocated between these nodes in proportion to their AMD or AMI over the three-year period.

5.6 If the load HHI is between 4,000 and 5,000, then charges on load are derated, with the derating increasing as the HHI descends towards 4,000 (refer to Figure 1).

5.7 If the generation HHI is between 4,000 and 5,000, then charges on generation are derated, with the derating increasing as the HHI descends towards 4,000.

5.8 Figure 2 shows the transmission lines that are classified as deeper connection assets in the simulated scenario. Current interconnection assets at some substations are also classified as deeper connection, but substations are not shown on the map.

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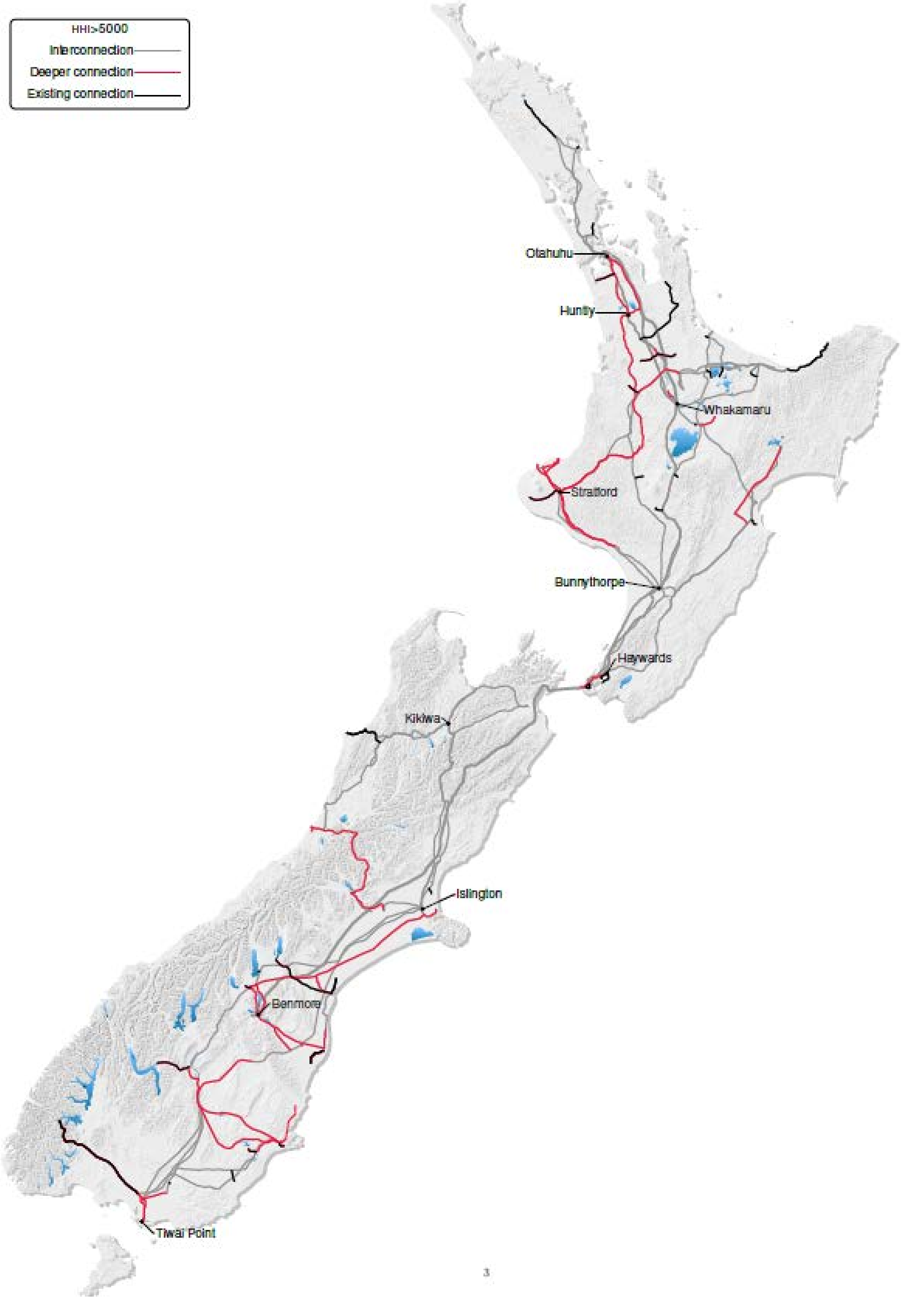
13 The scenario modelled, the simplifying assumptions applied, and details of the HHI calculation are set out in Appendix A. The effect of changing the HHI thresholds are set out in Appendix B.

14 The purpose of the 3 percent de minimus is to exclude nodes that make little use of the asset from the allocation of charges. Refer to Appendix C, and in particular, C.13 to C.18.

Figure 2: Transmission lines that are classified as deeper connection assets with HHI ≥ 5,000 in the simulated scenario

i. Deeper connection for load (HHI ≥ 5,000)

ii. Deeper connection for generation (HHI ≥ 5,000)



5.9 Under the modelling scenario, the revenue recovered by the deeper connection charge is approximately $300 million per year. Modelling of the charge in this paper relates to Application A only. Under Application B, there would be few assets covered by deeper connection in the initial years following a change to the TPM. Please refer to the options working paper for modelling of Application B.

5.10 There is relatively little recovery from generation parties. Around 20 percent of deeper connection charges would apply to generation parties. In the scenario, the modelled connection charge is split between generation ($35 million per year) and load ($102 million per year), while the modelled *deeper* connection charge is split between generation ($52 million per year) and load ($252 million per year).

5.11 The deeper connection assets allocated to generation parties would include:

(a) parts of the Wairakei Ring *(with costs paid by Contact, Mighty River Power and other owners of geothermal plants in the area)*

(b) some assets that are electrically close to Huntly Power Station *(with costs paid primarily by Genesis)*

(c) some lines between Otago, the Waitaki Valley and Christchurch *(with costs paid primarily by Contact and Meridian).*

5.12 Examples of deeper connection assets allocated to load parties in the simulated scenario, and the main parties that would pay for them, are:

(a) the North Island Grid Upgrade (NIGU) lines *(Vector)*

(b) the North Auckland and Northland project (NAaN) lines *(Vector, Northpower, Top Energy)*

(c) circuits between Stoke and Blenheim *(Marlborough Lines)*

(d) the West Coast Upgrade[15] lines *(Westpower)*

(e) circuits between Wairakei and Redclyffe *(Unison, Eastland Networks)*

(f) circuits between Woodville and Masterton *(Powerco, Wellington Electricity).*

5.13 In the scenario, the majority of deeper connection charges are paid by Upper North Island (UNI) mass-market load.

5.14 Figure 3 shows simulated deeper connection charges on load, in a 'heat map' format. The heat map does not include any allowance for generators passing their transmission charges to consumers in the form of higher energy prices.[16] This may be a reasonable assumption as the deeper connection charges on generators are specific to each generator.

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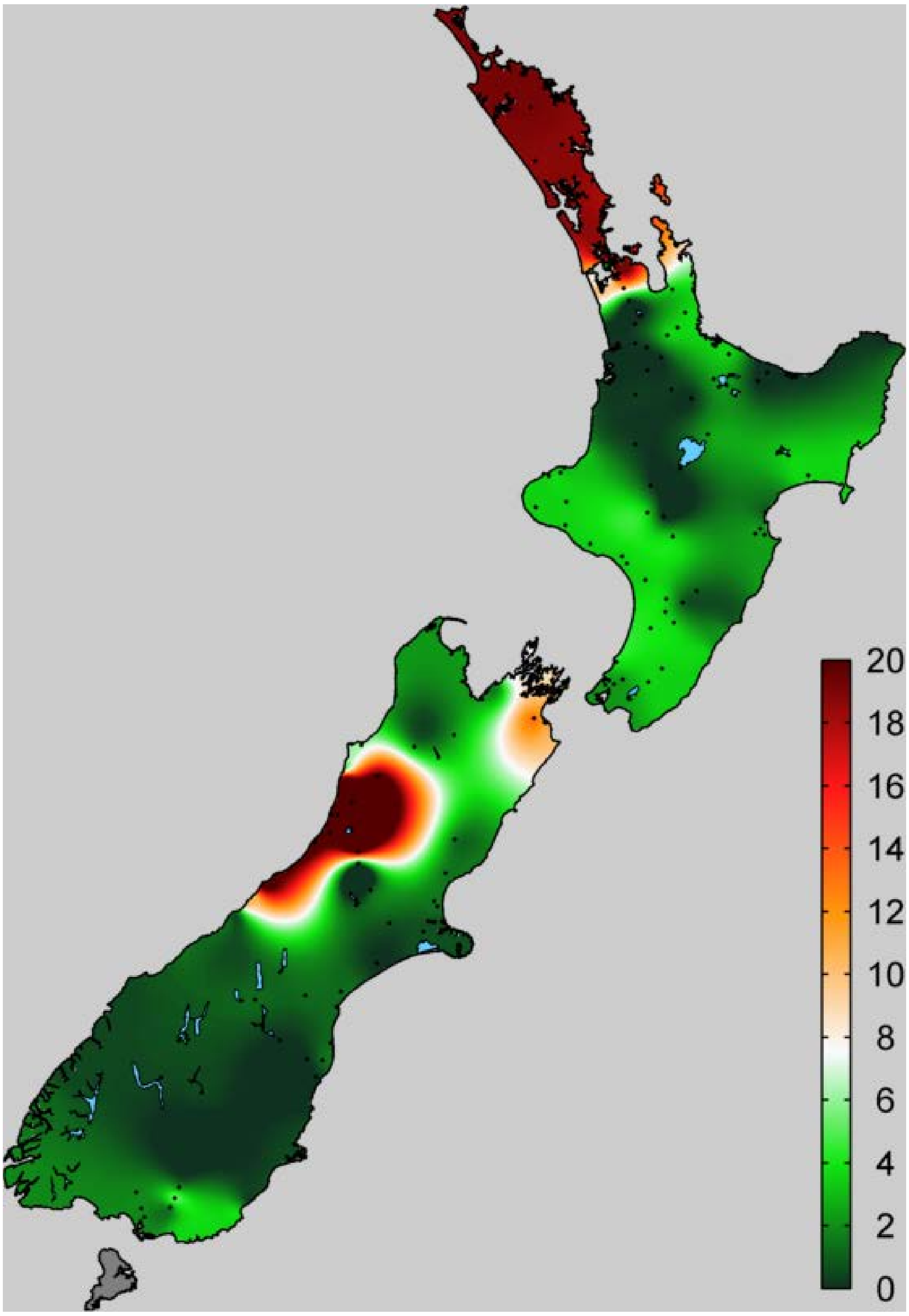
15 http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/west-coast-upgrade-plan/

16 The figures underlying the graph are provided in Appendix D.

Figure 3: Incidence of deeper connection charges on load, in fully variabilised terms (in $/MWh)[17]



The colour shown indicates the charge paid by each load party divided by their (approximate) total gross electricity consumption.

[17] This is net of LCE.

5.15 Simulated charges are highest (in variabilised terms) in the Vector, Northpower, Top Energy, Counties Power, Westpower, Buller Electricity and Marlborough Lines areas. The reasons for this are that the HHI threshold of approximately 5,000 means:

(a) for Vector, Northpower and Top Energy, the deeper connection charge would cover the costs of lines into Auckland and Northland, including NAaN and NIGU, which are currently recovered through the interconnection charge

(b) for Counties Power, the deeper connection charge would cover the costs of modelled future investment between Otahuhu and Wiri[18]

(c) for Westpower and Buller Electricity, the deeper connection charge would cover the costs of lines into the West Coast, which are currently recovered through the interconnection charge

(d) for Marlborough Lines, the deeper connection charge would cover lines from Kikiwa to Marlborough, which are currently recovered through the interconnection charge.

5.16 Some deeper connection assets are near the end of their economic life so the costs are heavily depreciated. This means that the deeper connection charges for the parties paying for these assets would be low.

<u>Examples of deeper connection calculations</u>

5.17 Consider, for example, the transmission link between Edgecumbe and Tarukenga.[19]

5.18 In the modelling, this link has a load HHI of 5,758 and a generation HHI of 2,628. It is therefore deemed to be deeper connection, with costs paid by load parties.

5.19 The load nodes whose use of the link is above the 3 percent cut-off are:

(a) KMO0331 (Kaitemako, modelled AMD is 22 MW)

(b) LFD1101 (Lichfield, 8 MW)

(c) MTM0331 (Mt Maunganui, 66 MW)

(d) ROT0111/0331 (Rotorua, 35 MW and 50 MW respectively)

(e) TGA0111/0331 (Tauranga, 29 MW and 84 MW respectively)

(f) TMI0331 (Te Matai, 32 MW)

(g) TRK0111 (Tarukenga, 9 MW).

5.20 The sum of these AMDs is 335 MW.

5.21 As a result, the modelling indicates that:

(a) Fonterra would pay 2 percent of the recoverable cost associated with the assets (LFD only = 8 MW / 335 MW = approx. 2 percent)

(b) Unison would pay 28 percent of the recoverable cost associated with the assets (ROT + TRK = 94 MW / 335 MW = 28 percent)

18 Note: it is not certain at this stage that any such investment will occur, or what form it might take, or when it might be completed. At the moment, Otahuhu-Wiri is still part way through the planning process.

19 This link consists of circuits EDG_TRK1.1 and EDG_TRK2.1.

(c) Powerco would pay the remaining 70 percent of the recoverable cost associated with the asset (KMO + MTM + TGA + TMI = 233 MW / 335 MW = 70 percent).

5.22 As a second example, consider the transmission link between Coleridge and Otira.[20]

5.23 In the modelling, this link has a load HHI of 9,994 and a generation HHI of 7,765. It is therefore deemed to be deeper connection, with costs paid by both load and generation parties.

5.24 The load nodes whose use of the link is above the 3 percent cut-off are:

(a) ATU1101 (Atarau, modelled AMD is 1 MW)

(b) DOB0331 (Dobson, 11 MW)

(c) GYM0661 (Greymouth, 14 MW)

(d) HKK0661 (Hokitika, 18 MW)

(e) KUM0661 (Kumara, 5 MW)

(f) OTI0111 (Otira, 0.7 MW).

5.25 The only generation node whose use of the link is above the 3 percent cut-off is COL0661 (Coleridge, modelled AMI is 39 MW).

5.26 The sum of these AMDs and AMI is 89 MW.

5.27 As a result, the modelling indicates that:

(a) Trustpower would pay 44 percent of the recoverable cost associated with the assets (COL = 39 MW / 89 MW = 44 percent)

(b) Westpower would pay the remaining 56 percent of the recoverable cost associated with the asset (ATU + DOB + GYM + HKK + KUM + OTI = 50 MW / 89 MW = 56 percent).

20 The example relates specifically to COL_OTI2.1.

6 Benefits of the deeper connection charge

6.1 The deeper connection charge may provide incentives for new deeper connection assets to be built under investment agreements with Transpower.[21] This contractual approach would reduce the need for parties having to pay for investments built to more stringent requirements than would be required under the regulated process.[22] It also provides incentives for EDBs to invest in their own lines when that would be more efficient than paying for a transmission upgrade.

6.2 The incentives for this are likely to be strong for EDBs, even though they are able to pass through transmission charges. This is because high transmission charges sufficient for customers to consider investing in technologies to allow them to disconnect from the grid increase the risk of stranding of distribution assets. This puts pressure on distributors' pricing.[23]

6.3 Relative to the status quo, the deeper connection charge has the following advantages:

(a) The deeper connection charge is market-like, and so promotes market-based investment that is closer to the needs of the parties subject to the charge.

(b) The deeper connection charge, if effectively targeted, promotes the potential for competition in the provision of services provided by deeper connection investments between Transpower and other service providers (including providers of alternatives to transmission services). The charge may not be much affected by demand growth unless this is sufficient for new parties to affect the HHI calculation.

6.4 In addition:

(a) The charge can apply to lines, transformers and substations not covered by the current connection charge (because those assets do not fall within the definition of connection assets).

(b) Calculation of the charge would use just the final pricing solution from SPD[24] and would not use new models (as it just uses SPD), regions, or zoning.

(c) The design of the deeper connection charge means that it would be reasonably stable and would not suffer the problems of the flow tracing transmission charging regime that applied in the 1990s, where charges changed dramatically because:

(i) of changes in the direction or pattern of power flows across the grid.

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21 However, to address the risk of hold-out by parties that were concerned about other customers connecting to the assets, it may be necessary to amend the Code to provide thatparties that negotiate investment agreements with Transpower would be credited with LCE in relation to the assets or pre-allocated FTRs for price differences across the assets. This would give the parties access to LCE arising on the asset and would compensate them if they were made worse off by other parties connecting to the asset.

22 That is, unless investment requirements are dictated by the Grid Reliability Standards.

23 EDBs could address the incentives for disconnection by offering discounted charges to those considering disconnecting and recovering the costs of this from other customers. Ultimately, though, this may not be sustainable, as the higher charges on other customers would make it more viable for them to consider disconnecting.

24 The final pricing solution from SPD is an input into the flow trace, which in turn is used to calculate the HHIs.

(ii) the flow tracing charge in the 1990s was calculated at only a few points of demand and, the Authority understands, for peak power flows, neither of which is the case for the deeper connection charge.[25]

6.5 Relative to the status quo, the deeper connection charge has the following disadvantages:

(a) Although the Authority considers that an HHI threshold of 5,000 is conservative, establishment of an appropriate HHI for the calculation may be controversial given that identifying assets as deeper connection is highly dependent on the HHI values used.

(b) It may incentivise parties to alter their behaviour to limit the extent to which they are subject to the charge, which could result in inefficiencies. However, this incentive may be muted for assets that would otherwise be subject to AoB or SPD charges.

(c) The deeper connection charge could discourage consolidation of parties such as EDBs if consolidation meant the HHI rose above the threshold for the deeper connection charge. This could be addressed through applying a lower HHI threshold.

(d) Under Application A, this charge would cause large changes to charges for some transmission customers. The options working paper presents some options for transitioning to the full deeper connection charge.

[25] Refer to Appendix C for further analysis of the stability of the deeper connection charge over time.

Appendix A Modelling scenario and simplifying assumptions

A.1 For the convenience of readers, this Appendix predominantly repeats the content of Appendix A in the options working paper.

The scenario

A.2 All three options and the status quo are applied to a hypothetical future scenario. The scenario covers a 3-year period, which is intended to represent the 2017, 2018 and 2019 calendar years.

A.3 The scenario assumes demand growth of 5% between 2011 and 2017 (slightly under 1% per year), and more rapid demand growth between 2017 and 2019.

A.4 These assumptions represent faster demand growth than has been observed in recent years. The Authority plans to repeat the analysis for lower and higher demand growth sensitivities and publish the results on its website during the consultation period.

A.5 The scenario assumes that two coal-fired Huntly units are available, and that no other thermal generation plants will retire before the end of 2019.

A.6 The scenario assumes that a new 50 MW geothermal plant will be commissioned near Wairakei at the start of 2019 (in order to meet demand growth). No other new generation investment is modelled.

A.7 Mighty River Power has recently announced it will decommission Southdown[26] and increase capacity at Whakamaru.[27] Further, Meridian has announced it will increase capacity at Waitaki.[28] These changes are not included in the scenario, because the Authority did not become aware of them until after modelling work had begun. The Authority will revisit this as part of the modelling work for the second issues paper.

A.8 The scenario assumes that the following transmission investments will be completed by 2017:[29]

(a) Lower South Island (LSI) Reliability

(b) LSI Renewables

(c) BPE-HAY reconductoring.

A.9 The Authority appreciates that, in reality, some of these three investments may not be fully commissioned by 2017.

A.10 In addition, the scenario assumes that the following transmission investments will be completed between 2017 and 2019:

(a) PAK-WKM series compensation[30]

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26 Mighty River Power, Media Release, Renewables growth behind closure of Southland thermal station, 24 March 2015.

27 Refer to: NZ Energy and Environment publication, 12 November 2014, Vol 11, No. 30, page 1.

28 Refer to: http://ecogeneration.com.au/news/hydro_powering_on_in_new_zealand/080465/.

29 Refer integrated transmission plan at: https://www.transpower.co.nz/about-us/industry-information/rcp2-submission-and-itp/rcp2-regulatory-templates.

(b) some form of investment reinforcing OTA-WIR[31]

(c) interconnecting transformers at OTA and PEN[32]

(d) OTB-HAY reconductoring.[33]

A.11 In reality, it is uncertain whether or when these four investments will take place, or in what form, as they are still in the planning process.

Implementing the scenario in vSPD

Approach

A.12 The scenario has been implemented using the Authority's vSPD model.[34] Minor modifications have been made to the vSPD code for this purpose, aimed mainly at producing the required outputs.

A.13 The scenario is produced by:

(a) taking real final pricing cases from the 2011, 2012 and 2013 calendar years, in the GDX format used by vSPD

(b) modifying the GDX files as described below[35]

(c) using the (slightly modified) version of vSPD to solve the cases

(d) loading selected vSPD output files into a SQL database.
(The Authority has published a copy of this table, so that participants can reproduce the calculation of simulated charges without needing to rerun vSPD.)

A.14 The 2017 year of the scenario is based on modified 2011 final pricing cases, the 2018 year on modified 2012 cases, and the 2019 year on modified 2013 cases.

Demand assumptions

A.15 Demand at all nodes except Tiwai and Kawerau is scaled up by:

(a) 5% in 2017 (compared to 2011)

(b) 7% in 2018 (compared to 2012)

(c) 9% in 2019 (compared to 2013).

A.16 Demand at Tiwai is unmodified. Demand at KAW0112 and KAW0113 is scaled down by roughly 40%.

30 Refer integrated transmission plan at: https://www.transpower.co.nz/about-us/industry-information/rcp2-submission-and-itp/rcp2-regulatory-templates.

31 Refer Section 6.4.2 of Transpower's RCP2 proposal at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/main-proposal-rcp2.pdf.

32 Refer Section 6.4.2 of Transpower's RCP2 proposal at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/main-proposal-rcp2.pdf.

33 Refer integrated transmission plan at: https://www.transpower.co.nz/about-us/industry-information/rcp2-submission-and-itp/rcp2-regulatory-templates.

34 http://www.emi.ea.govt.nz/Tools/vSPD

35 For the convenience of submitters, the Authority is considering preparing an alternative version of the analysis that does not use modified GDX files. Instead, it would use the main (trunk) version of vSPD and unmodified GDX files, and employ overrides to produce the desired scenario. If the Authority does this, it will publish the files on its website during the consultation period.

A.17 Demand-side bids are modelled at the following nodes: KAW0112, KAW0113, KIN0111, KIN0112, KIN0113, WHI0111. These bids are based on actual bids into the spot market price-responsive schedule (PRS). Bid quantities at Kawerau are, again, scaled down by roughly 40%.

A.18 The Authority appreciates that, in practice, some of these parties might not place dispatchable demand bids. However, modelling these demand-side bids in the scenario helps to represent the price sensitivity of the relevant loads.

A.19 The Authority became aware, just before publication of this paper, that there were errors in the way it had constructed synthetic demand-side bids at Kawerau and Kinleith. Only about 1% of trading periods were affected. The Authority has tested the effect of this error on prices and quantities in the scenario and concludes that it is not material.

<u>Generation assumptions</u>

A.20 Synthetic offers are used for the two remaining coal-fired units at Huntly – with roughly half the capacity being offered at $0/MWh, and the remainder offered at up to $100/MWh.

A.21 The new 50 MW geothermal generator is modelled as baseload.

A.22 The following plants, which were commissioned after the beginning of 2011, are modelled as being in place throughout the entire 3-year period:

(a) Te Mihi and Ngatamariki geothermal (modelled as baseload)

(b) Mill Creek wind (output assumed to be proportional to West Wind)

(c) McKee peaker (actual offers used where available, otherwise offers from Stratford 2 used where available, otherwise 100 MW offered at $150/MWh).

A.23 No attempt is made to track simulated hydro storage or to consider how this might result in changes to generation offers (relative to the actual offers made in 2011-13).

A.24 No attempt is made to consider how the various transmission charging options might affect participant behaviour.

<u>Transmission network assumptions</u>

A.25 All days in the scenario use the network configuration from 31 July 2013, modified to include the NAaN upgrade, Wairakei Ring, LSI Reliability, LSI Renewables and BPE-HAY reconductoring.

A.26 Shoulder and summer line ratings are modelled as being 95% and 90% of the winter line rating, respectively.

A.27 Where a node does not exist in the 31 July 2013 network configuration, its demand is shifted to a node that does exist:

(a) load at DAR0111 and MPE0331 is moved to MPE1101

(b) load at KOE0331 and KTA0331 moved to KOE1101

(c) load at KKA0331 is moved to CUL0661

(d) load at OKI0111 is moved to OKI2201

(e) load at PAP is moved to ISL0661.

A.28 Instantaneous reserve requirements are adjusted to reflect the availability of the bipole HVDC throughout the three-year period. In particular:

(a) DCCE i_HVDCPoleRampUp is set to 700

(b) DCCE i_FreeReserve is set to the maximum of DCCE i_FreeReserve and GENRISK i_FreeReserve

(c) i_TradePeriodBranchCapacity is set to approximately 700 for the HVDC poles

(d) additional types of risk parameter associated with Pole 3 commissioning are removed.

A.29 Group and branch constraints are turned off in the vSPD modelling:

(a) in order to avoid the difficulty of determining the constraint parameters that will apply in 2017-19

(b) to reflect that most constraints that might bind would either be managed operationally or resolved through investment

(c) on the assumption that the results of interest (simulated transmission charges) are not sensitive to the inclusion of group and branch constraints.[36]

A.30 Investments assumed to be commissioned between 2017 and 2019 (that is, PAK-WKM series compensation, OTA-WIR reinforcement and ICTs at OTA and PEN) are not modelled in vSPD – in large part, because it is not clear what form these investments will take. However, these investments are taken into account when modelling deeper connection charges.

A.31 For the purpose of modelling transmission charges, Cobb is treated as being an embedded generator.

Revenue to be recovered

A.32 It is assumed Transpower's non-connection revenue requirement will be approximately $1,000M per year (excluding static reactive support costs). This is broadly consistent with Transpower's forecast revenue.[37] The revenue requirement assumes no change in revenue as a result of Transpower's individual price path.

A.33 Some charges are based on the revenue requirements associated with specific investments. The assumed revenue requirements, based on indicative information supplied by Transpower, are set out in Table 1.

36 The Authority is carrying out an experiment to test whether this assumption is valid for the deeper connection charge, and plans to publish the results during the consultation period.

37 Refer: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/RCP2%20revenue%20-%20revised%20forecast%20%28July%202014%29.pdf.

Table 1: Assumed revenue requirements for specific investments

Investment	Assumed revenue requirement ($M per year)	Reference
NIGU	91	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2005-gup/north-island-grid-investment-proposal/
NaaN	34	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/
LSI Renewables	27	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-renewables/
Wairakei Ring	13 *(modelling indicates that only part of this revenue would be recovered through the deeper connection charge)*	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/
Otahuhu GIS	11	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/
UNI dynamic reactive support	8	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/
USI reactive support (IGE 4)	5	https://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/

<table>
<tr><th>Investment</th><th>Assumed revenue requirement ($M per year)</th><th>Reference</th></tr>
<tr><td>LSI Reliability</td><td>3</td><td>http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-reliability/</td></tr>
<tr><td>PAK-WKM series compensation</td><td>7</td><td>Integrated transmission plan at https://www.transpower.co.nz/about-us/industry-information/rcp2-submission-and-itp/rcp2-regulatory-templates</td></tr>
<tr><td>Some form of investment reinforcing OTA-WIR</td><td>3</td><td rowspan="2">Section 6.4.2 of Transpower's RCP2 proposal at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/main-proposal-rcp2.pdf</td></tr>
<tr><td>ICTs at OTA and PEN</td><td>3</td></tr>
</table>

(Note: It is unclear whether or when the last three investments listed will take place, or in what form, as they are still in the planning process.)

A.34 It is also assumed that $50M per year of post-FTR non-connection LCE will be available to offset transmission charges.

Simplifying assumptions in the calculation of the deeper connection charge

A.35 This subsection is not intended to be stand-alone – it should be read alongside the description of the deeper connection charge in the main text of this paper.

A.36 Existing connection assets, and the HVDC link, are not eligible to become deeper connection assets.

A.37 The classification of assets modelled in SPD as connection or interconnection, and the calculation of the Regulatory Asset Base (RAB) value associated with each SPD asset, are both somewhat approximate. In practice, Transpower would be able to perform these calculations more accurately.

A.38 The revenue requirement associated with each asset (including depreciation, Transpower's recovery of its capex costs, and O&M attributed to the asset) is assumed to be 15 percent of the RAB value. This is an approximation. In practice, the ratio of revenue requirement to asset value would vary between assets.

A.39 The following provides details on the HHI calculation for identifying deeper connection assets:

(a) The methodology utilises a power flow tracing algorithm developed by the Authority that is able to accurately determine the main users of interconnection assets. It allocates the flow across each asset in each trading period between load or generation users of the asset. These flow shares are then averaged across trading periods.

(b) The output of the vSPD analysis, used to prepare the scenario, is an input to the flow tracing analysis.

(c) The load HHI calculation is based on the averaged flow shares of load parties; the generation HHI calculation is based on the averaged flow shares of generation parties.

(d) An asset is considered to be deeper connection if it has an HHI in excess of 4,000 for either load or generation.

(e) If the HHI is above 5,000 the revenue requirement in relation to the asset is fully recovered through the deeper connection charge.

(f) If the HHI is between 4,000 and 5,000, then the amount to be recovered is derated. A linear derating is applied – for instance, if the load HHI of an asset is 4,500, then deeper connection charges on load for that asset are halved.

A.40 If an asset is identified as deeper connection, then the deeper connection charges associated with the asset are allocated between load nodes (if it has a load HHI in excess of 4,000) and generation nodes (if it has a generation HHI in excess of 4,000) that are deemed to be 'connected by' the asset – in proportion to their AMD or AMI respectively.

A.41 A node is deemed to be connected by a particular deeper connection asset if the node's mean flow share for the asset is at least 3 percent of its AMD (for a load node) or its AMI (for a generation node).

A.42 If there are multiple load parties at a node, then the charge is modelled as being allocated between these load parties in proportion to their share of total electricity consumption at the node. (In practice, the charge might instead be allocated in proportion to contribution to AMD.)

A.43 Investments assumed to be commissioned between 2017 and 2019 (that is, PAK-WKM series compensation, OTA-WIR reinforcement and ICTs at OTA and PEN) are not included in the flow tracing – in large part, because it is not clear what form these investments will take. However, these investments are taken into account when modelling deeper connection charges. The allocation of charges for these investments is carried out on an ad hoc basis, based on the Authority's understanding of the parties that would likely be deemed to be 'connected by' the relevant assets.

A.44 The post-FTR LCE occurring across each deeper connection asset is assumed to offset the deeper connection charges for that asset.

A.45 Post-FTR LCE occurring on deeper connection assets is estimated by:

(a) determining the rentals produced by each asset in the vSPD scenario

(b) scaling all rentals so they sum to \$165 million over 3 years (\$55 million per year).

Appendix B Effect of changing the HHI cut-off

B.1 Under the deeper connection method, a key design decision is the choice of HHI cut-off. Increasing the cut-off value reduces the number of assets classified as deeper connection for load and generation.

B.2 Figures 4 and 5 illustrate the effect of increasing the cut-off value.

B.3 Some examples of the effect of the cut-off value follow.

B.4 In the modelling, some examples of assets with an HHI above 7,000 are circuits between:

(a) Stoke and Blenheim

(b) Inangahua and Dobson

(c) Henderson and Albany.

B.5 Some examples of assets with an HHI between 5,000 and 6,000 are circuits between:

(a) Stratford and Huntly

(b) Haywards and Takapu Rd

(c) Redclyffe and Tuai.

B.6 Some examples of assets with an HHI between 3,000 and 4,000 are circuits between:

(a) Islington and Kikiwa

(b) Ashburton and Islington

(c) Bunnythorpe and Brunswick.

B.7 Increasing the cut-off value reduces the amount of revenue recovered through the deeper connection charge. In the simulated scenario, the deeper connection charge would recover:

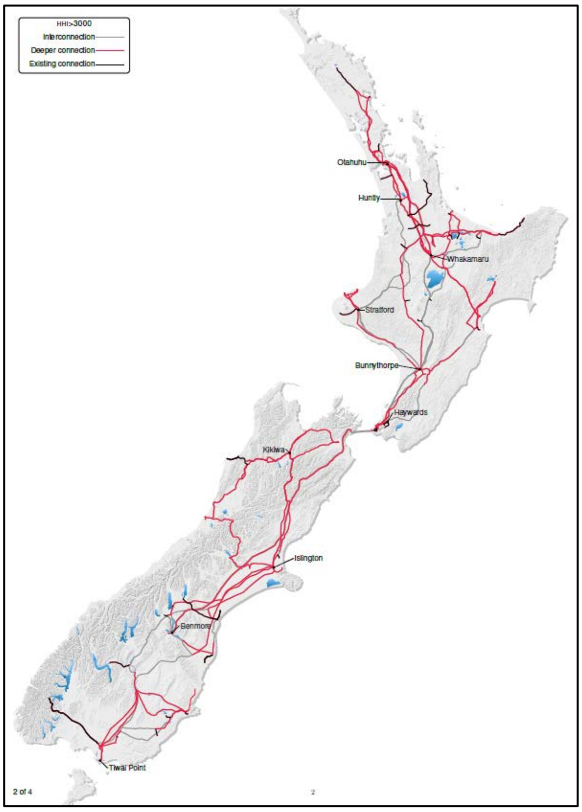
(a) $246M per year with a graduated cut-off from HHI=6,000 to 7,000

(b) $304M per year with a graduated cut-off from HHI=4,000 to 5,000

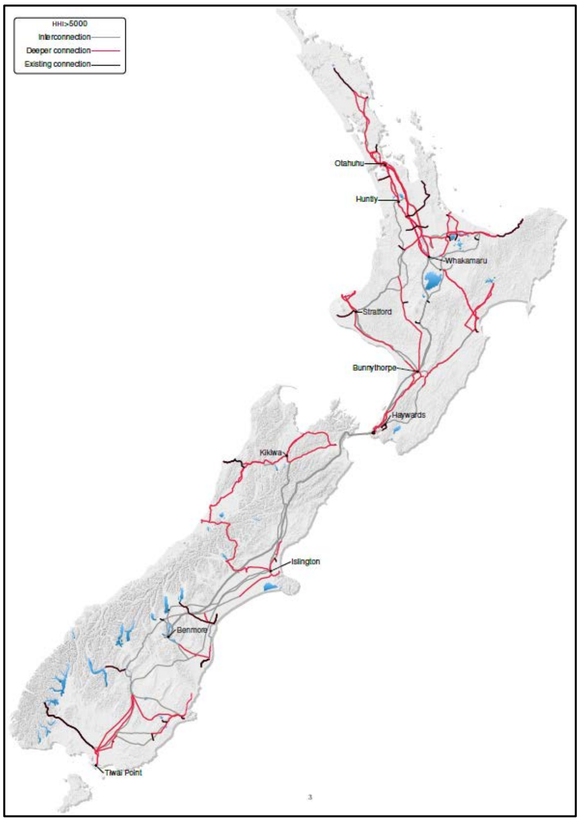
(c) not substantially more with a graduated cut-off from HHI=2,000 to 3,000, as the relatively small increase in charges would be offset by an increase in LCE to be returned to deeper connection customers.

Figure 4: Classification of assets for load – with a cut-off of HHI ≥ 3,000, 5,000 *(reproduced from the main text)*, and 7,000

HHI ≥ 3,000



HHI ≥ 5,000



HHI ≥ 7,000

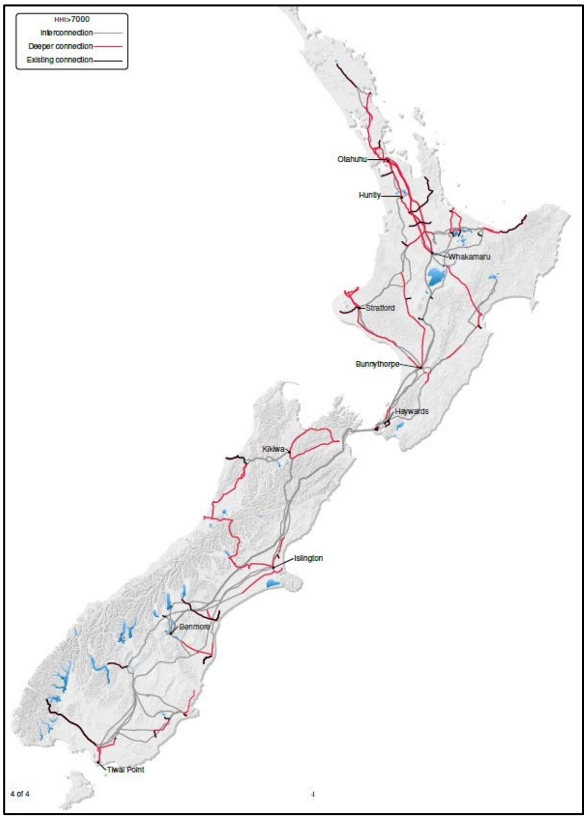
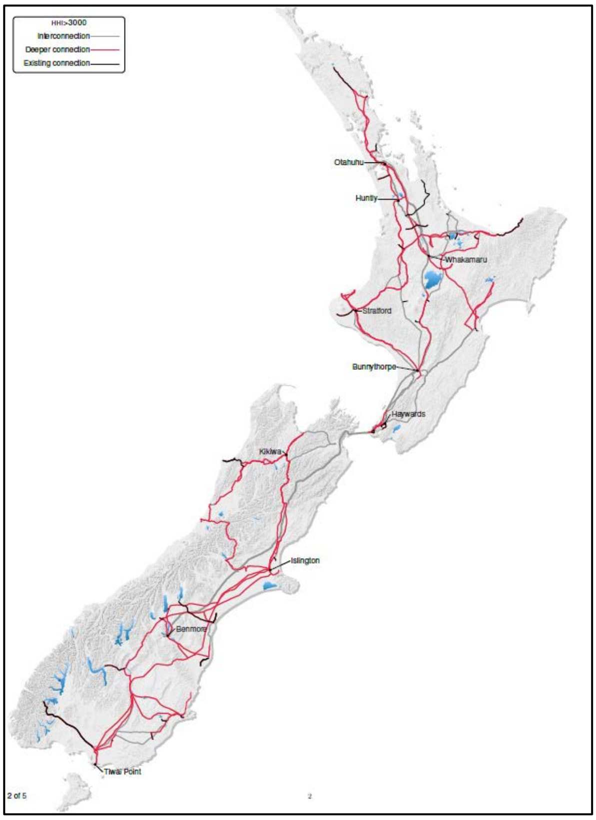
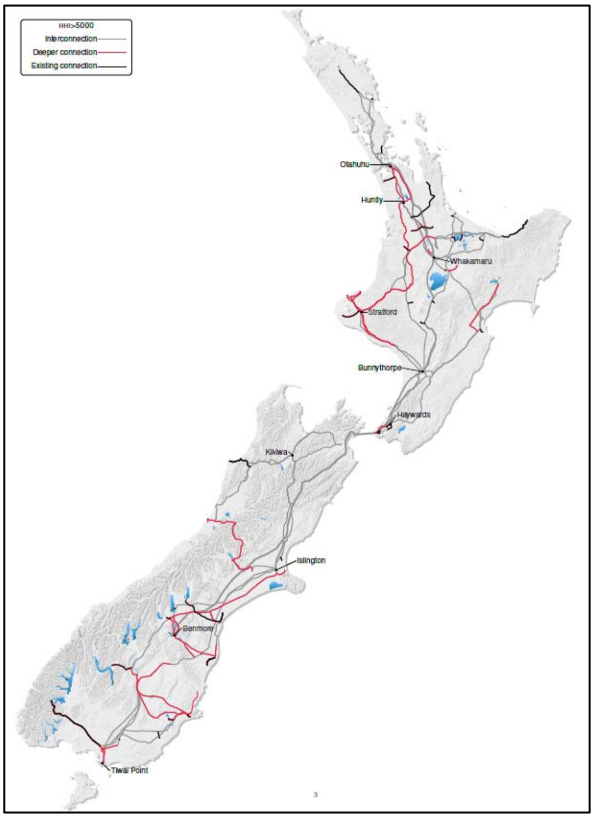


Figure 5: Classification of assets for generation – with a cut-off of HHI ≥ 3,000, 5,000 *(reproduced from the main text)*, and 7,000

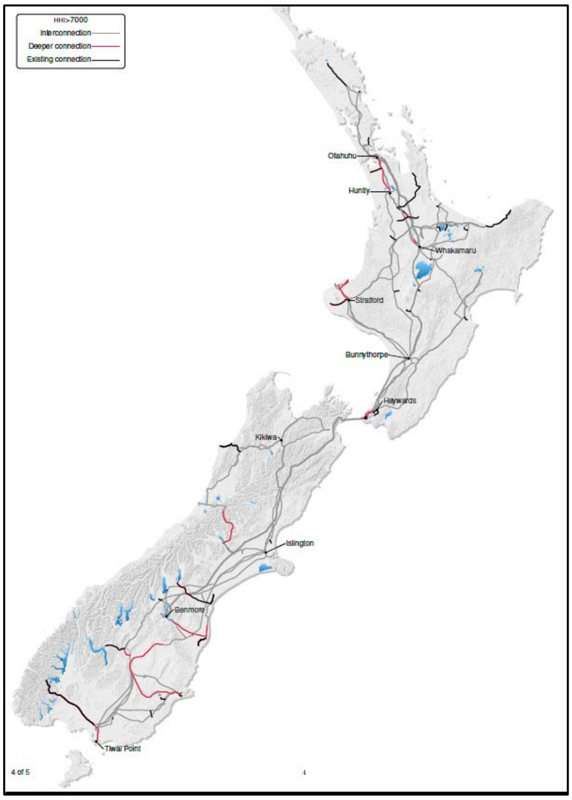
HHI ≥ 3,000



HHI ≥ 5,000



HHI ≥ 7,000



Appendix C The stability of the deeper connection charge

C.1 This Appendix assesses the stability of the deeper connection charges.

C.2 The revenue recovered from the deeper connection charges may vary over time as a result of:

(a) the addition of new interconnection assets to, or the removal of existing interconnection assets from, Transpower's RAB

(b) changes in the amount of money to be recovered with respect to a specific interconnection asset

(c) an interconnection asset being reclassified between 'deeper connection' and 'true interconnection'

(d) a change in the list of nodes identified as being 'connected by' a deeper connection asset.

C.3 The Authority is not concerned about changes in deeper connection charges as a result of cause (a) or (b) above, which are legitimate reasons for changes in charges.

C.4 The Authority would, however, be concerned if causes (c) and/or (d) above led to substantial volatility in deeper connection charges.

C.5 Therefore, the Authority has investigated:

(a) how frequently interconnection assets would be reclassified between 'deeper connection' and 'true interconnection'

(b) how frequently the list of nodes identified as being 'connected by' a given deeper connection asset would change.

C.6 Rather than working with a simulated future scenario, the Authority has analysed a historical period. The deeper connection method has been applied to actual market solves between:

(a) 2009 and 2011 inclusive

(b) 2012 and 2014 inclusive.[38]

<u>Reclassification between deeper connection and true interconnection</u>

C.7 The Authority assessed how many interconnection assets would have been classified as:

(a) deeper connection for the period from 2009 to 2011, but true interconnection for the period from 2012 to 2014, or

(b) true interconnection for the period from 2009 to 2011, but deeper connection for the period from 2012 to 2014.

C.8 It would be of concern if many assets would have been reclassified in this way.

C.9 A set of 334 assets represented in SPD (including both lines and substations) were identified for the purposes of the assessment. All these assets:

[38] It would have been better to compare two five-year periods, but there was insufficient historical data.

(a) are currently classified as interconnection

(b) existed throughout the 2009-2014 period

(c) also exist in the TPM modelling scenario

(d) have non zero flows.

C.10 Of these 334 assets, only two assets flip from a full deeper connection charge to a non-deeper connection charge and none for the reverse. In detail:

(a) only two would have been classified as:

(i) fully deeper connection for the period from 2009 to 2011 (with load HHI over 5,000 or generation HHI over 5,000)

(ii) fully true interconnection for the period from 2012 to 2014 (with both HHIs below 4,000).

(b) none would have been classified as:

(i) fully true interconnection for the period from 2009 to 2011 (with both HHIs below 4,000)

(ii) fully deeper connection for the period from 2012 to 2014 (with load HHI over 5,000 or generation HHI over 5,000).

C.11 The two assets mentioned under (a) above are:

(a) BPE_WIL1.2 which would have been deeper connection for load in 2009-11, but not in 2012-14[39]

(b) TMN_TWH1.1 which would have been deeper connection for generation in 2009-11, but not in 2012-14.[40]

C.12 The modelling indicates there would be little volatility from year to year in the classification of interconnection assets as 'deeper connection' or 'true interconnection'. In large part, this is due to the use of a 'graduated cut-off' from HHI = 4,000 to 5,000. In the absence of the graduated approach, there would be many more investments that changed from 'deeper connection' to 'true interconnection' or vice versa.[41]

<u>Changes in the list of nodes 'connected by' a deeper connection asset</u>

C.13 A set of 240 assets represented in SPD (including both lines and substations) were identified for the purposes of the assessment. All these assets would have been classified as 'deeper connection' for load, both in 2009-11 and in 2012-14.

C.14 A load node is deemed to be 'connected by' a transmission asset that is deeper connection for load, if the mean flow share of the load node over the transmission asset is at least 3 percent of the load node's AMD.

39 Bunnythorpe, Wilton.

40 Taumarunui, Te Kowhai.

41 Some examples include the circuits between (a) Ashburton, Timaru, and Twizel, (b) Edgecumbe and Tarukenga, and (c) Huntly and Stratford.

C.15 Of the 240 load nodes modelled in vSPD, 30 percent were considered either to be:

(a) ‘connected by’ some transmission asset in 2009-11, but not ‘connected by’ the same asset in 2012-14, or

(b) ‘connected by’ some transmission asset in 2012-14, but not ‘connected by’ the same asset in 2009-11.

C.16 For instance:

(a) TGA0331 was deemed to be 'connected by' KAW substation in 2012-14, but not in 2009-11[42]

(b) RDF0331 was deemed to be 'connected by' FHL_RDF1.1, FHL_RDF2.1 and FHL_TUI1.1 in 2009-11, but not in 2012-14[43]

(c) KUM0661 was deemed to be 'connected by' DOB_GYM.1 in 2012-14, but not in 2009-11.[44]

C.17 The Authority anticipates these kinds of changes over time could lead to significant volatility in deeper connection charges.

C.18 It may be possible to reduce the frequency of changes in the list of nodes ‘connected by’ a deeper connection asset by:

(a) introducing a graduated cut-off around the 3 percent threshold, for example, determining that a node is ‘partly connected by’ a deeper connection asset if its flow share over that asset is equal to 2.9 percent of its AMD

(b) using some other method of allocating deeper connection charges that does not rely on identifying nodes that are ‘connected by’ a given deeper connection asset.

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42 Tauranga, Kawerau.

43 Redclyffe, Fernhill, Tuai.

44 Kumera, Dobson, Greymouth.

Appendix D Modelled breakdown of the incidence of deeper connection charges

D.1 The incidence of simulated deeper connection charges in the scenario is shown in:

(a) Table 2a, in '$M per year' terms

(b) Table 2b, in '$ per ICP per year' terms, and

(c) Table 2c, in $/MWh terms.

D.2 Some geothermal power plants (such as Nga Awa Purua) are separated out for ease of reference.

D.3 Some industrial consumers are also separated out for ease of reference even though, in practice, their transmission charges might be paid indirectly through a network or retailer.

Table 2a Modelled incidence of deeper connection charges ($M per year)

Distributors		**Generators**		**Major industrials**	
Alpine Energy	1.05	Contact	22.69	CHH	0.60
Aurora Energy	0.81	Fonterra	0.09	Daiken MDF	0.09
Buller Electricity	0.73	Genesis	6.36	Kiwirail	0.00
Counties Power	4.95	Meridian	16.71	Methanex	0.12
Eastland Network	1.14	Mokai JV	0.08	Norske Skog	0.00
Electra	1.93	MRP	2.10	NZ Steel	0.10
Electricity Ashburton	0.00	NAP JV	1.17	NZAS	1.86
Horizon	0.08	Ngatamariki	0.60	Pacific Steel	0.53
Mainpower	0.83	NZ Wind Farms	0.00	PanPac	0.39
Marlborough Lines	5.19	Pioneer	0.00	Rayonier	0.32
Network Tasman	1.92	Todd	0.49	Winstones	0.00
Network Waitaki	0.00	Trustpower	1.16		
Northpower	19.76				
Orion	2.62				
Powerco	15.80				
PowerNet	3.10	(incl. The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)			
Scanpower	0.09				
The Lines Company	0.11				
Top Energy	6.80				
Unison	4.54	(incl. Centralines)			
Vector	165.1				
Waipa Power	0.01				
WEL	0.22				
Wellington Electricity	6.25				
Westpower	6.03				

Table 2b Modelled incidence of deeper connection charges on EDBs ($ per ICP per year)

EDB	Charge
Alpine Energy	33
Aurora Energy	9
Buller Electricity	160
Counties Power	127
Eastland Network	45
Electra	45
Electricity Ashburton	0
Horizon	3
Mainpower	23
Marlborough Lines	211
Network Tasman	41
Network Waitaki	0
Northpower	358
Orion	14
Powerco	50
PowerNet	48
Scanpower	13
The Lines Company	5
Top Energy	221
Unison	39
Vector	303
Waipa Power	0
WEL	3
Wellington Electricity	37
Westpower	454

Note: The figures in Table 2b represent the charge on the EDB divided by the number of active ICPs in the network area. Because they are averaged across both residential and commercial ICPs, they are likely to exceed the charge on a typical residential ICP.

Table 2c Modelled incidence of charges, on a fully variabilised basis ($/MWh)

Distributors		Generators		Major industrials	
Alpine Energy	1.37	Contact	2.08	CHH	0.94
Aurora Energy	0.58	Fonterra	0.64	Daiken MDF	1.16
Buller Electricity	6.29	Genesis	0.79	Kiwirail	0.01
Counties Power	10.18	Meridian	1.43	Methanex	2.55
Eastland Network	3.68	Mokai JV	0.09	Norske Skog	0.00
Electra	4.09	MRP	0.39	NZ Steel	0.09
Electricity Ashburton	0.00	NAP JV	1.00	NZAS	0.37
Horizon	0.16	Ngatamariki	0.94	Pacific Steel	2.61
Mainpower	1.57	NZ Wind Farms	0.00	PanPac	0.75
Marlborough Lines	13.10	Pioneer	0.00	Rayonier	5.53
Network Tasman	2.32	Todd	0.82	Winstones	0.00
Network Waitaki	0.00	Trustpower	0.58		
Northpower	18.78				
Orion	0.79				
Powerco	3.46				
PowerNet	2.06	Incl. The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland			
Scanpower	0.98				
The Lines Company	0.36				
Top Energy	19.32				
Unison	2.46	(incl. Centralines)			
Vector	18.44				
Waipa Power	0.02				
WEL	0.17				
Wellington Electricity	2.32				
Westpower	20.44				

Note: The figures in Table 2c represent:

- *for generators, charge divided by generation injection*
- *for major consumers, charge divided by load offtake*
- *for EDBs, charge divided by approximate gross electricity consumption.*

Some generators with relatively small injection quantities are omitted.