

# Review of distributed generation pricing principles

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## Consultation Paper

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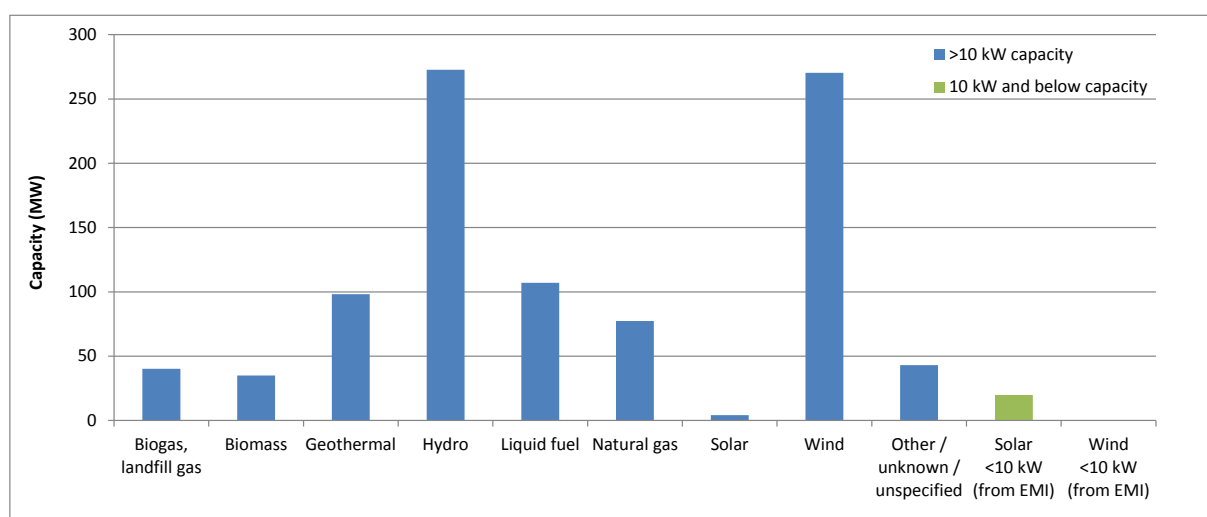
## Executive summary

### The purpose of this paper is to consult on a proposal

The purpose of this paper is to consult with interested parties on the Authority’s proposal to remove the distributed generation pricing principles from Part 6 of the Electricity Industry Participation Code 2010 (Code).

Generation connected to a local distribution network is called distributed generation. It ranges from small scale (below 10 kW in capacity) such as rooftop solar, to hydro power stations and wind farms. In New Zealand, larger-scale plant (above 10kW) makes up over 98% of total distributed generation by capacity. Figure 1 shows the breakdown of distributed generation by size and type.

Figure 1: Size and types of distributed generation



Distributed generation owners typically use services provided by distribution networks, and may provide services to those networks. In this, they are not unique—households and industrial consumers can also provide network support services, for example, through demand response.<sup>1</sup>

Distributed generation owners and distributors can negotiate agreements to receive and provide these services. If they do not agree terms, Part 6 of the Code provides for default terms, called regulated terms, to apply. Part 6 includes a set of distributed generation pricing principles (DGPPs) which form the basis of the charges under the regulated terms.

<sup>1</sup> Demand response means end-use consumers intentionally altering their normal consumption patterns in response to electricity price changes, or in response to incentive payments designed to induce lower electricity use at particular times.

The Authority has been reviewing the DGPPs to ensure they promote competition in, reliable supply by, and efficient operation of the electricity industry for the long-term benefit of consumers.<sup>2</sup> The Authority has identified two key problems:

- a) The DGPPs require distributors to charge owners of distributed generation no more than the incremental cost for connection and distribution services. This requirement does not promote efficiency. This is the 'connection services issue'.
- b) The provisions in the DGPPs relating to transmission do not promote efficient decisions about investing in, and operating, distributed generation. This is the 'avoided cost of transmission' (ACOT) issue.<sup>3</sup>

Available information strongly indicates that the ACOT issue causes appreciable losses in efficiency. The connection services issue also appears likely to be causing efficiency losses, although the effects are more difficult to quantify.

The Authority is proposing to remove the DGPPs from Part 6 of the Code. This would address both issues. The efficiency benefits of the change are estimated to be in a range from \$0.5 million to \$21.7 million (present value). Gross benefits to consumers are estimated to be in a range from \$46 million to \$325 million (present value) (due to the proposed reduction in subsidies paid to owners of distributed generation and notionally embedded generators).<sup>4, 5</sup>

This gross benefit to consumers is a wealth transfer that is outside the Authority's statutory objective. The issue is included as background information. There are also efficiency benefits associated with these gross benefits. This is because the existing payments to distributed generation owners raise electricity prices to end-consumers, thereby distorting their consumption decisions. The Authority has considered this effect in calculating the efficiency benefits noted above.

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<sup>2</sup> This is the Authority's statutory objective, which is set out in section 15 of the Electricity Industry Act 2010.

<sup>3</sup> The pricing principles in Schedule 6.4 of the Code require distributors to pay distributed generation owners for reductions in transmission and distribution costs that arise from connecting distributed generation to their network. In practice, payments have been made chiefly for reductions in transmission costs. Reductions in transmission costs are often termed the Avoided Cost of Transmission (ACOT). Reductions in distribution costs are termed the Avoided Cost of Distribution (ACOD).

<sup>4</sup> Notionally embedded generators are grid-connected generators where the owner has an agreement with Transpower (as grid owner), that contractually mimics aspects of the arrangements applying to a distributed generator.

<sup>5</sup> This may be an overestimate of gross benefits if ACOT payments to generators have caused an oversupply of generation resulting in higher reliability and/or a suppressed spot price compared with an efficient outcome.

## The DGPPs do not promote efficiency

### The DGPPs allow distributed generation owners to avoid paying a share of common costs (the connection services issue)

The DGPPs do not promote efficiency because they prevent distributors from setting prices for distributed generation that include a share of common network costs.

Prices convey information to producers and users of goods and services. Prices therefore influence production and consumption decisions, and affect whether consumers and producers use resources to generate the greatest possible total benefit to society. This is also known as maximising overall efficiency.

To promote overall efficiency, the prices charged for distribution services should at least cover the incremental cost of that service and not exceed the standalone cost (the cost of the next best alternative). The Authority's voluntary distribution pricing principles stipulate that distributors should charge in a range from incremental cost to standalone cost. Within this range, prices should be set to recover common costs in a way that causes the least possible distortion to behaviour but with the caveat that those prices are set in ways that avoid distorting production and investment decisions. This approach minimises overall efficiency losses and maximises 'the size of the economic pie'.

The DGPPs do not promote efficiency because they make incremental cost the upper limit for charges paid by owners of distributed generation for connection services. Given that "connection services" includes distribution services provided to distributed generation, this means owners of distributed generation are not required to pay a share of common network costs.<sup>6</sup> Instead, these costs must be borne entirely by other network users—in particular, electricity consumers. As many electricity consumers are also producers—eg, commercial and industrial firms that use electricity—the DGPPs are likely to be distorting production and investment decisions throughout the economy, reducing the size of the New Zealand economy.

While it may be efficient for owners of distributed generation not to contribute to common costs in some situations, it is unclear why this would be efficient in all cases. Further, charging distributed generation owners solely based on incremental costs in all cases is likely to understate the full cost of providing distribution services to distributed generation. This is likely to encourage inefficient distributed generation investment or operation.

The DGPPs apply if a distributor and a distributed generation owner cannot agree on a connection contract. Owners of distributed generation can opt to have prices based on the DGPPs. This means they have the option to avoid contributing to common costs for distribution services.

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<sup>6</sup> At least in their capacity as owners of distributed generation as defined under the Code.

By requiring distributors to charge owners of distributed generation no more than incremental costs, the DGPPs in Part 6 are inconsistent with the Authority's voluntary distribution pricing principles. The voluntary pricing principles guide distributors in determining their approach to setting prices and developing their pricing methodologies. One goal of the distribution pricing principles is that distribution prices should signal the economic costs of service provision by distributors. It is unclear why any single category of distribution network user should be favoured over others, as occurs under the DGPPs.

### **The DGPPs fail to encourage distributed generation to reduce transmission costs (the ACOT issue)**

Distributed generation can affect transmission costs. To promote efficiency, prices should signal these effects, but the DGPPs do not achieve this.

Depending on the circumstances, distributed generation can reduce, increase, or have no effect on transmission costs. To promote overall efficiency, transmission-related effects (either benefits or costs) should be properly signalled to distributed generation owners, so they can take account of the effects in their investment and operating decisions.

The DGPPs do not achieve this. Instead, they require distributors to signal to distributed generation owners the avoided/additional transmission charges the distributor would otherwise pay in the absence of distributed generation, that is, the cost of transmission to the distributor. These avoided/additional charges do not necessarily reflect the avoided/additional transmission costs. As a result, there can be over- or under-signalling of transmission costs and benefits. This in turn will encourage inefficient distributed generation investment and/or operation. It could also create inefficiencies with respect to evolving technologies (for example the development of micro grids).

Although the DGPPs only apply to distributed generation (ie, generation physically connected to distribution networks), they are also likely to influence the investment and operating decisions of notionally embedded generators.<sup>7</sup> Thus, the DGPPs may also encourage inefficient investment in and operation of grid-connected generation that is notionally embedded.

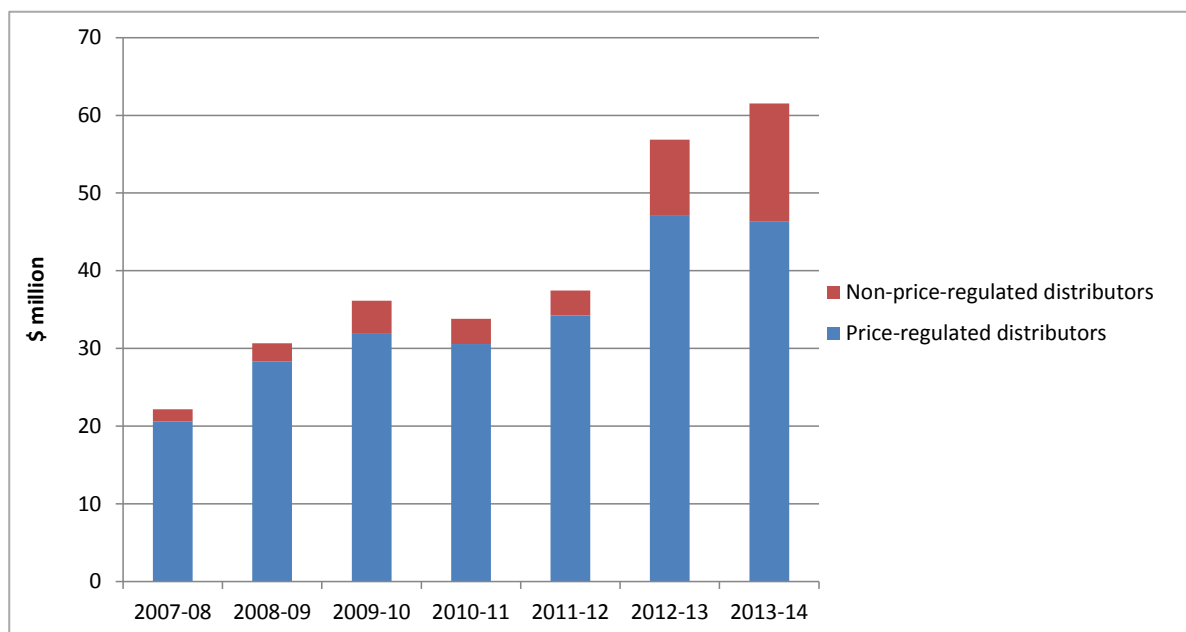
For the year ended March 2014, distributors reported \$62 million for 'avoided transmission charges', based on disclosures to the Commerce Commission. It is likely that distributors would have paid most of this total to owners of distributed generation and notionally embedded generation in the form of ACOT payments.<sup>8</sup>

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<sup>7</sup> See section 3.3 for the reasons.

<sup>8</sup> The \$62 million also includes allowances for instances where distributors purchased an asset from Transpower. See footnote 53 for further details.

Figure 2: Recoverable cost allowance for 'avoided transmission charges'

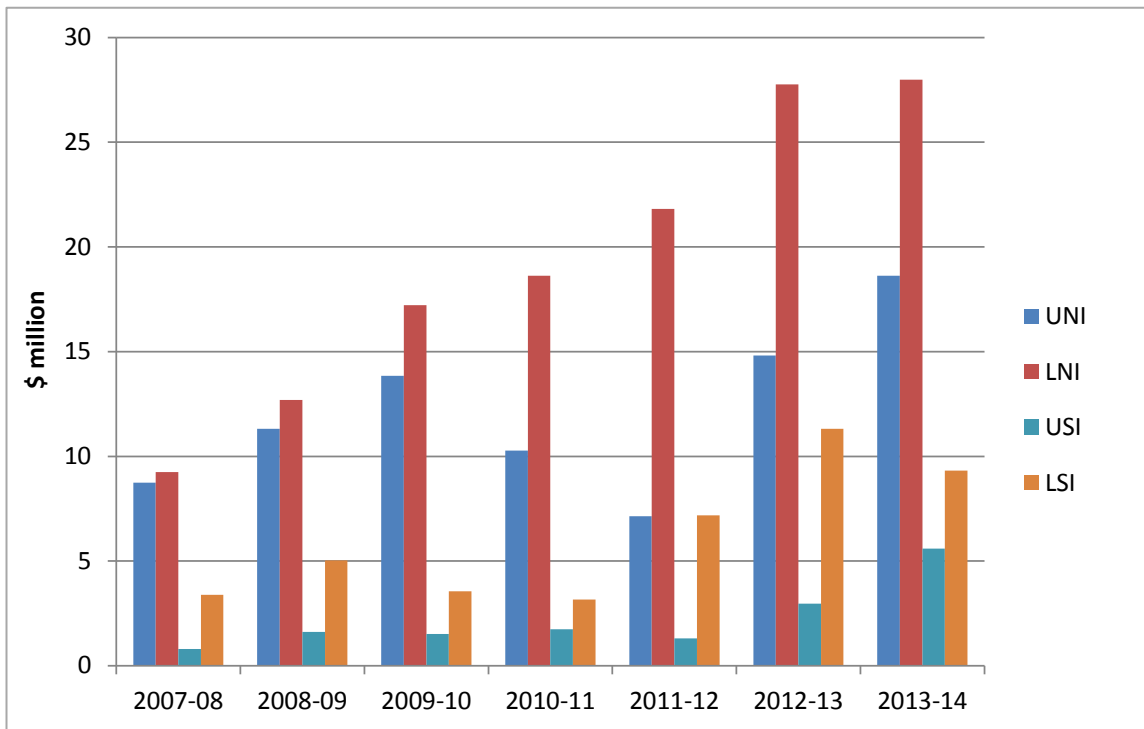


As Figure 2 shows, the allowance for the 'avoided transmission charges' category has almost tripled over the last six years to 2014. The growth has occurred at a time when transmission capacity has expanded substantially. The Authority would generally expect this to reduce the extent to which the operation of distributed generation defers investment in the transmission network.

Figure 3 shows the breakdown of the allowance by transmission region. Of the \$62 million allowance in 2014, approximately \$37 million (60%) related to the lower South Island (LSI) and lower North Island (LNI) regions.<sup>9</sup> However, the Authority expects that the actual avoidable cost of transmission in these regions has been relatively low or nil, because these regions are not import constrained.

<sup>9</sup> The LSI and LNI regions, together with the upper South Island (USI) and upper North Island (UNI) regions, were defined for transmission pricing purposes in 2006. At that time, major grid upgrades were planned to increase transmission capacity to the UNI and USI regions. Accordingly, if price signals were sent to customers in the UNI and USI regions, new transmission investment might be able to be deferred, resulting in efficiency gains.  
[https://www.transpower.co.nz/sites/default/files/uncontrolled\\_docs/TPM\\_2006\\_%20Supplementary\\_Material.pdf](https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/TPM_2006_%20Supplementary_Material.pdf)

Figure 3: Cost allowance for 'avoided transmission charges' by region



This information suggests that a large part of ACOT payments is providing little or no benefit in terms of the deferral of transmission costs. It is questionable whether the growth over six years of approximately \$25 million in annual ACOT payments to some generation in the LSI and LNI regions yields worthwhile transmission benefits. Instead, it is more likely that consumers are paying an extra cost of around \$25-\$35 million per annum without receiving an associated benefit.

This transfer from consumers to some owners of distributed generation and notionally embedded generation can create efficiency losses. These arise because the payments can encourage inefficient investment or operation of distributed generation and also reduce allocative efficiency.

**The transmission pricing methodology review affects the ACOT issue**

The Authority is currently reviewing the transmission pricing methodology (TPM). The results of this review will affect the size of the inefficiencies caused by the ACOT issue and are relevant to assessing the solutions to that issue.

The effects described in the previous paragraphs are influenced by the degree of misalignment between transmission charges and transmission costs. Under the current TPM, the degree of misalignment can be substantial.

The Authority considers that there is potential for alternative options to the current TPM to better promote the Authority’s statutory objective. If the review results in changes to the TPM,



this may reduce the misalignment between transmission charges and costs. However, because the results of the review are not yet known, the Authority has considered a scenario where the TPM does not change. If the TPM does change, some years could pass before that change affects transmission charges and reduces the misalignment. Further, even if the TPM does change, it is unlikely that transmission charges and costs will be fully aligned in all situations. For these reasons, a new TPM alone is unlikely to fully address the problems identified.

## **The Authority proposes to remove the DGPPs from the Code**

The Authority proposes to amend the Code to address both the connection services issue and the ACOT issue. The proposal is to remove the DGPPs from Part 6 of the Code. The Authority's voluntary distribution pricing principles guide development of distributors' pricing methodologies for distribution pricing generally. The Authority considers that a separate set of pricing principles for distributed generation is not necessary.

The proposed Code amendment is included in Appendix B.

## **The proposed amendment would address the connection services issue**

Removing the DGPPs would address the connection services issue because distributors would no longer be required (by the DGPPs) to treat distributed generation on a preferred basis when they set charges for distribution services. This would better allow distributors to adopt service-based charging structures across all users of distribution networks, including owners of distributed generation. It would also reduce the likelihood of inefficient investment in and operation of distributed generation.

The change would promote the Authority's statutory objective because:

- (a) The proposal would support the efficiency limb by better allowing distributors to adopt service-based pricing structures across all users of distribution networks, including owners of distributed generation. It would achieve this by removing the DGPPs, which prohibit distributors from recovering any common costs from the owners of distributed generation. As noted above, removing this constraint would also reduce the likelihood of inefficient investment in, or the operation of, distributed generation.
- (b) The proposal would not have a major effect on the competition limb. However, by making under-pricing of distribution services to distributed generation owners less likely, it may better promote efficiency-enhancing competition between distributed generation and grid-connected generation. That is, subsidy-driven sources of competition, which typically harm economic efficiency, may be reduced.
- (c) The proposal would not detract from the reliability limb because it would not reduce incentives for distributed generation investment and operation where there is a genuine reliability benefit. Where distributed generation is needed to provide a local reliability benefit (ie, avoid investment to reinforce the distribution network to address a

constraint) this can be recognised via avoided cost of distribution (ACOD) payments. Where distributed generation provides a wider reliability benefit, the wholesale electricity market provides the appropriate incentives, and removing the DGPPs will not alter those incentives.

### **The proposed amendment would address the ACOT issue**

Removing the DGPPs would address the ACOT issue because it would leave Transpower solely responsible for obtaining and paying for transmission-substitute services that distributed generation provides. The Commerce Act 1986 provides for Transpower to take on this responsibility.<sup>10</sup>

Under the proposed Code amendment, distributors providing connection services to distributed generation owners under the regulated terms would no longer have to take account of the effect on transmission charges when setting connection charges. Where distributed generation provides a genuine transmission-substitute service, Transpower and distributed generators can make agreements that recognise this.

The objective of the proposed Code amendment (with respect to the ACOT issue) is to better align the responsibility for obtaining/paying for transmission-substitute services provided by distributed generation with the party that has the best information, ability and incentives to assess the value of those services – ie, Transpower. The Authority expects that Transpower will enter into agreements with owners of distributed generation whose operation could efficiently reduce or defer transmission network costs.

In summary, the Commerce Act 1986 provides incentives for Transpower to provide a defined level of transmission service at the lowest possible cost.

Removing the DGPPs from the Code would promote the Authority's statutory objective in the following ways:

- (a) It would support the efficiency limb by reducing incentives for inefficient investment in and/or operation of distributed generation that does not reduce transmission network costs.
- (b) It would support the competition limb because it will reduce the scope for distributed generation to be artificially advantaged, relative to grid-connected generation.
- (c) It would not detract from the reliability limb. Where distributed generation provides a genuine ACOT service, the Authority expects that Transpower has the ability and incentives to contract for such services. As part of its assessment, Transpower would

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<sup>10</sup> The Commerce Act 1986 provides that Transpower can enter into arrangements with owners of distributed generation to procure 'non-transmission services', ie, substitutes for conventional transmission services. The regime provides incentives for Transpower to procure non-transmission solutions where it would be more efficient than investing in transmission assets. Appendix C further explains the Commerce Act 1986 regime applying to Transpower.

take into account any reliability benefits provided by distributed generation. More generally, to the extent that distributed generation provides other reliability benefits (incentivised via sale of energy), the proposal will not affect those incentives.

### **The Authority proposes a phased transition**

The Authority proposes that the Code amendment would have effect from:

- 1 April 2017 for distributed generation located in the LNI and LSI regions
- 1 April 2018 for distributed generation located in the USI and UNI regions.

The phased approach would:

- allow time for Transpower and distributed generation owners to develop and document agreements where required
- deliver most of the net benefit of the proposed new ACOT payment regime early in the transition, as distributed generation located in the LNI and LSI transmission regions are considered least likely to deliver avoided transmission benefits
- align with network pricing years, which commence 1 April.

The Authority seeks submissions on when the proposed Code amendment should come into force.

### **Cost benefit analysis shows a net economic benefit**

The Authority has evaluated the costs and benefits of the proposal in terms of its ability to address the ACOT issue. It has concluded that the proposal would produce a net economic benefit, relative to the current DGPPs, across a range of scenarios concerning the future state of the TPM.

The Authority has considered the following potential economic benefits:

- (a) reducing inefficient, out-of-merit **operation** of distributed generation (and notionally embedded generation) that does not reduce or defer transmission investment costs
- (b) reducing the scope for **retention** of distributed generation (and notionally embedded generation) that does not reduce or defer transmission investment costs, and whose retention is not justified by other benefits (such as local or market-wide reliability)
- (c) reducing inefficient, out-of-merit **investment** in new distributed generation (and notionally embedded generation) that does not reduce or defer transmission investment costs in an efficient (ie, lowest cost) manner
- (d) reducing the **allocative efficiency loss** that results from consumers paying more than is necessary, and altering their consumption decisions.

The Authority does not expect the proposal to have any significant adverse effects on efficiency. Although distributed generation can reduce transmission and distribution losses, the most significant of these are transmission network losses. The location-specific wholesale market prices received by generators (including distributed generators) already take into account transmission network losses. This price signal, which contributes to generators making an efficient location decision, will not be affected by the Authority's proposal.

Further, the Authority does not expect the proposal to reduce dynamic efficiency by undermining investor confidence in the stability of regulatory arrangements. Dynamic efficiency and investor confidence are enhanced by the Authority actively pursuing the promotion of its statutory objective. The level and basis of ACOT payments has not been a 'settled' area of policy. In these circumstances, it is reasonable to expect prospective distributed generation investors to have evaluated their investments based on genuine transmission benefits, rather than relying on windfall transfers (such as ACOT payments). Under the proposal, investment in distributed generation that genuinely reduces transmission costs will proceed, which will promote dynamic efficiency.

The Authority also expects the proposal to result in positive effects on competition, since it will make the playing field more level between distributed generation and grid-connected generation. Distributed generators will continue to locate in and operate in regional areas of New Zealand to the extent that it is efficient for them to do so.

The Authority does not expect the proposal to have any adverse effects on reliability. If the proposal were adopted, distributed generators would continue to receive payment for producing electricity through the wholesale market. Most electricity generation in this country (including 70-80% of distributed generation) is renewable and so has very low operating costs. Even if ACOT payments were reduced, it is very unlikely that many (if any) distributed generators would shut down. There is a possibility that some planned investment in distributed generation will not go ahead if ACOT payments are reduced or not available. However, countering this effect, the reduction or removal of ACOT payments may encourage new generation investment in grid-connected generation, or the retention of existing grid-connected generation. Therefore, it is not clear that reducing or removing ACOT payments would lead to a reduction in the total amount of generation available. In any event, a change in the amount of generation available would not necessarily affect the promotion of the reliability limb of the statutory objective, as the Authority considers reliability to be "efficient reliability".

The Authority has evaluated each of these benefits under three different TPM options, and the results are summarised in Table 1 below. The estimated economic benefits of the proposal fall in the range from \$0.5 million to \$21.7 million present value, depending on various uncertainties including the future development of the TPM. The Authority considers that the economic costs (dynamic inefficiency, transaction costs and productive inefficiency) of the proposal are expected to be relatively immaterial or nil.

The Authority therefore concludes that the expected net economic benefit of the proposal is positive, across a range of scenarios encapsulating the Authority’s current uncertainty about future TPM development.

The Authority has also calculated the gross benefits to consumers that would result from the proposal.<sup>11</sup> The gross benefits to consumers from the proposal are estimated to sit in the range from \$46 million to \$325 million present value, depending on various uncertainties including the future development of the TPM.<sup>12</sup> There are also efficiency benefits associated with these gross benefits. This is because the existing payments to distributed generation raise electricity prices to end-consumers, thereby distorting their consumption decisions. The Authority has considered this effect in calculating the efficiency benefits noted in the table below.

Table 1: Expected economic benefits and gross benefits resulting from the proposal, relative to the current DGPPs

	<b>Expected economic benefits, in \$million present value terms</b>	<b>Gross benefit to consumers, in \$million present value terms</b>
Current TPM	2.0 – 21.7	232 – 325
Current TPM for two years from April 2017, then area-of-benefit-based TPM	0.5 – 4.2	46 – 64 plus effect after 2019 (not quantified)

As the table above illustrates, the proposal has lower economic benefits in the scenario that involves the area-of-benefit-based TPM. This is because significant economic costs are expected under the current DGPPs in the other scenario (the current TPM scenario), primarily through incentives for inefficient investment in distributed generation. These incentives for inefficient investment in distributed generation are expected to be lower in the scenario involving the area-of-benefit-based TPM because the operation of distributed generation has less effect on transmission pricing under the area-of-benefit-based TPM than under the current TPM.

In addition to the above quantitative assessment for the ACOT issue, the Authority has also undertaken a qualitative assessment of the proposal relative to the status quo, in terms of its

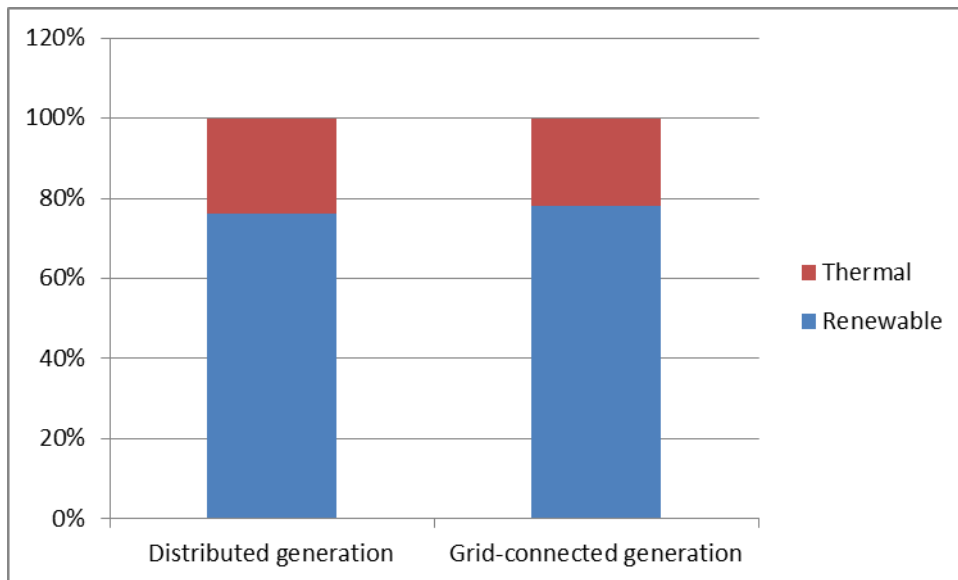
<sup>11</sup> Gross benefits to consumers include wealth transfers. The Authority does not take into account wealth transfers, but it does take into account any efficiency effects that may arise from wealth transfers. Information on gross benefits is included here for information, as it may be a relevant consideration for other policy makers and stakeholders.

<sup>12</sup> This may be an overestimate of gross benefits if ACOT payments to generators have caused an oversupply of generation resulting in higher reliability and/or a suppressed spot price compared to an efficient outcome.

ability to address the connection services issue. Overall, based on the available information, the Authority considers that the proposal is likely to have net positive benefits.

The Authority does not expect that the proposal will have negative effects on environmental outcomes.<sup>13</sup> In principle, the Emissions Trading Scheme would give an advantage to renewable generation (including distributed generation) to the extent that it produces relatively low greenhouse gas emissions. In any case, distributed generation is not significantly more renewable than grid-connected generation. A large proportion (between 70% and 80%) of both types of generation is renewable, as Figure 4 illustrates.<sup>14</sup> Further, over 95% of new grid-connected and distributed generation proposals that are planned to progress, and that have received planning consents, are for renewable generators.<sup>15</sup> This suggests that generation entering the market in future will most likely be overwhelmingly renewable, regardless of our proposal.

Figure 4: Proportion of generation renewable and thermal



<sup>13</sup> The Authority does not take into account environmental effects. This discussion is included here for information, as it may be a relevant consideration for other policy makers and stakeholders.

<sup>14</sup> Data on grid-connected generation sourced from *Energy and Building Trends*, published by MBIE (2014 data). Data on distributed generation sourced from the Authority’s August 2015 survey of distributors on distributed generation above 10 kW, discussed in section 2.1.

<sup>15</sup> Information is not available in all cases on whether proposed new generation will be grid-connected or distributed, however, larger plant are more likely to be grid-connected and smaller plant are more likely to be distributed. Refer to the Authority’s Proposed generating plant update, available on the Authority’s EMI website: [http://www.emi.ea.govt.nz/Datasets/Browse?directory=%2FProposed&parentDirectory=%2FDatasets%2FWholesale%2FGeneration%2FGeneration\\_fleet](http://www.emi.ea.govt.nz/Datasets/Browse?directory=%2FProposed&parentDirectory=%2FDatasets%2FWholesale%2FGeneration%2FGeneration_fleet)

The Authority does not expect that the proposal will have negative effects for regional employment.<sup>16</sup> Most grid-connected generators are located in the regions, and employ people in these regions. Also, distributed generators will continue to locate in and operate in regional areas of New Zealand to the extent that it is efficient for them to do so. Due to the low operating cost of most distributed generation, it is unlikely that many (if any) distributed generators would shut down if ACOT payments were reduced.

### **The Authority has identified alternatives, but prefers its proposal**

The Authority has identified three alternatives, under which it would amend, rather than remove, the pricing principles applying to the setting of connection charges for distributed generation.

The three alternatives would address the connection services issue in the same way: by amending the DGPPs so that charges must be in the range from incremental cost to standalone cost of providing those services. The differences between the three alternatives relate to how they address the ACOT issue:

- (a) Alternative 1 – exclude transmission costs or charges from the definition of “incremental cost” in the DGPPs.
- (b) Alternative 2 – ban on ACOT payments by distributors. The Authority would amend the Code to prohibit distributors from paying generators, or seeking payment from generators, in respect of avoided transmission charges or costs. As under the proposal, Transpower could pay generators for efficiently reducing or deferring transmission network costs.
- (c) Alternative 3 – Transpower approves ACOT payments. Distributors would make ACOT payments to distributed generation owners if, and only if, Transpower approved the arrangement as efficiently deferring or reducing transmission investment costs. The approval process would be set out in new Code provisions.

Relative to the status quo, the Authority expects the three alternatives to provide broadly similar ACOT-related benefits and costs to the preferred option. The Authority has assessed the proposal and the three alternatives against the ‘tie breaker’ Code amendment principles 4-8, and concluded that the proposal is most consistent with the ‘tie breaker’ principles.

### **The Authority invites submissions on the proposed Code amendment**

The Authority invites interested parties to make submissions on its proposal to amend Part 6 of the Code by removing the DGPPs (Schedule 6.4), to address the problems identified. The process for making submissions is set out in section 1.2.

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<sup>16</sup> The Authority does not take into account effects on employment. This discussion is included here for information, as it may be a relevant consideration for other policy makers and stakeholders.





## Glossary of abbreviations and terms

<b>Act</b>	Electricity Industry Act 2010
<b>ACOD</b>	Avoided Cost of Distribution
<b>ACOT</b>	Avoided Cost of Transmission
<b>Authority</b>	Electricity Authority
<b>Code</b>	Electricity Industry Participation Code 2010
<b>Charge</b>	Amount paid by customer for specific service
<b>Cost</b>	Resource (ie, economic) cost of providing specific service
<b>DGPPs</b>	Distributed Generation Pricing Principles in Schedule 6.4 of the Code
<b>EMI</b>	The Authority's Electricity Market Information website
<b>kW</b>	A kilowatt, a measure of generation capacity
<b>LNI</b>	The lower North Island transmission region
<b>LRMC</b>	Long-run marginal cost
<b>LSI</b>	The lower South Island transmission region
<b>MW</b>	A megawatt, a measure of generation capacity equal to 1000 kW
<b>Notionally embedded generation</b>	Grid-connected generation where the owner has an agreement with Transpower (as grid owner), that contractually mimics aspects of the arrangements applying to a distributed generator, including generators that receive a discount under the prudent discount policy in Schedule 4 of the Code
<b>Part 6</b>	Part 6 of the Code, which sets out provisions relation to connection of distributed generation
<b>RCPD</b>	Regional coincident peak demand
<b>Regulations</b>	Electricity Industry (Enforcement) Regulations 2010
<b>Schedule 6.4</b>	Schedule 6.4 of the Code, which sets out the DGPPs
<b>SRMC</b>	Short-run marginal cost
<b>TPM</b>	Transmission Pricing Methodology
<b>Transpower</b>	Transpower New Zealand Ltd, owner of the transmission grid
<b>UNI</b>	The upper North Island transmission region
<b>USI</b>	The upper South Island transmission region

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# 1. What you need to know to make a submission

## 1.1 The purpose of this paper is to consult on a proposal

- 1.1.1 The purpose of this paper is to consult with interested parties on the Authority's proposal to remove the DGPPs from Part 6 of the Code.
- 1.1.2 Distributed generation is generation connected directly to a distribution network. Distributed generation owners typically use services provided by distribution networks, and may provide services to those networks.
- 1.1.3 Distributed generation owners and distributors can agree terms to receive and provide these services. If they do not agree terms, default terms, called regulated terms, will apply.<sup>17</sup> Part 6 of the Code contains a set of pricing principles that form the basis of charges in the regulated terms.<sup>18</sup>
- 1.1.4 The Authority is considering whether the pricing arrangements in Part 6 of the Code promote competition in, reliable supply by, and efficient operation of the electricity industry for the long-term benefit of consumers.<sup>19</sup>
- 1.1.5 The Authority proposes to amend the pricing arrangements in Part 6 (including removing some parts) to better align with the Authority's statutory objective. The amendment would remove the DGPPs from the Code. This would address two main issues:
- (a) charging for distribution-related services (the connection services issue)
  - (b) charging for transmission-related services (the ACOT issue).
- 1.1.6 Section 39(1)(b) and (c) of the Act require the Authority to prepare and publicise a regulatory statement on any proposed amendment to the Code and to consult on the proposed amendment and regulatory statement.<sup>20</sup> Section 39(2) provides that the regulatory statement must include:
- (a) a statement of the objectives of the proposed amendment
  - (b) an evaluation of the costs and benefits of the proposed amendment
  - (c) an evaluation of alternative means of achieving the objectives of the proposed amendment.

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<sup>17</sup> The default terms are specified in Schedule 6.2 of Part 6 of the Code.

<sup>18</sup> In Schedule 6.4 of Part 6 of the Code.

<sup>19</sup> The Authority's statutory objective, which is set out in section 15 of the Electricity Industry Act 2010, is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

<sup>20</sup> This requirement applies in normal circumstances. There are some exceptions, including those set out in section 39(3).

1.1.7 The regulatory statement is set out in section 4.

1.1.8 The proposed amendment is set out in Appendix B.

## 1.2 How to make a submission

1.2.1 The Authority prefers to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix A. Submissions in electronic form should be emailed to [submissions@ea.govt.nz](mailto:submissions@ea.govt.nz) with 'Consultation Paper – A default agreement for distribution services' in the subject line.

1.2.2 If you cannot send your submission electronically, post one hard copy of the submission to either of the addresses provided below, or you can fax it to 04 460 8879. You can call 04 460 8860 if you have any questions.

### Postal address

Submissions  
Electricity Authority  
PO Box 10041  
Wellington 6143

### Physical address

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

1.2.3 Please deliver your submission by 5pm on 26 July 2016. The Authority may not consider late submissions.

1.2.4 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.

1.2.5 Please note the Authority wants to publish all submissions it receives. If you consider that it should not publish any part of your submission, please:

- (a) indicate which part should not be published
- (b) explain why you consider the Authority should not publish it
- (c) provide a version of your submission that the Authority can publish (if it agrees not to publish your full submission).

1.2.6 If you indicate there is part of your submission that should not be published, the Authority will discuss it with you before deciding whether to not publish that part of your submission.

1.2.7 However, please note that all submissions the Authority receives, including any parts that it may not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release them unless good reason existed under the Official Information Act to withhold them. The Authority would normally consult with you before releasing any material that you said should not be published.

## **2. Network pricing arrangements for distributed generation**

### **2.1 Distributed generation takes many forms**

- 2.1.1 In New Zealand, generation plants connected to the national grid produce most of New Zealand's electricity. The grid conveys electricity to lower-voltage local distribution networks. Distributors transport electricity to consumers' premises on the local distribution network.
- 2.1.2 Some power plants are not directly connected to the grid. A power plant connected to a local distribution network is called distributed generation.<sup>21</sup> Because distributed generation is embedded in a distribution network (rather than connected to the grid), it is also known as embedded generation.
- 2.1.3 Distributed generation encompasses a range of technologies and scales, including mid-sized hydro schemes and wind farms through to small-scale systems such as solar panels, small wind turbines and micro-hydro schemes.
- 2.1.4 In August 2015, the Authority asked each distributor for information about distributed generation plant connected to the distributor's network.<sup>22</sup> The survey asked about distributed generation plants above 10 kW capacity because they account for over 98% of distributed generation.
- 2.1.5 The responses indicate there is around 950 MW of such distributed generation across New Zealand.<sup>23</sup> Figure 5 shows how the total capacity is broken down by generation size and type. The Authority has sourced data for distributed generation below 10 kW in capacity from its Electricity Market Information (EMI) website.

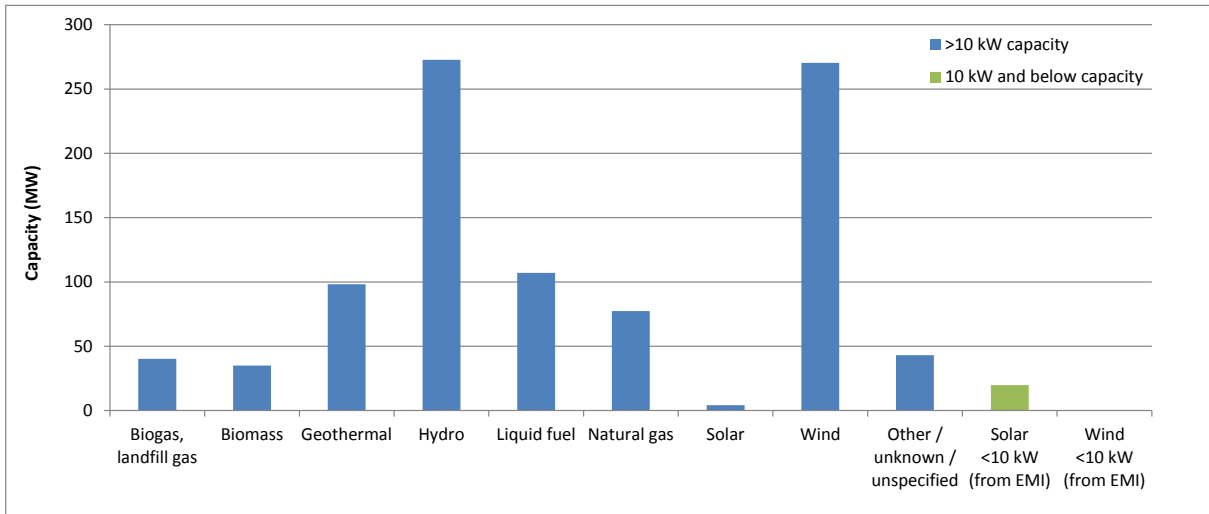
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<sup>21</sup> Distributed generation is defined in Part 1 of the Code.

<sup>22</sup> The Authority greatly appreciates the high response rate it received to the survey, and wishes to thank distributors for the information they provided. The Authority notes that the survey results may not capture all distributed generation that is above 10 kW in capacity.

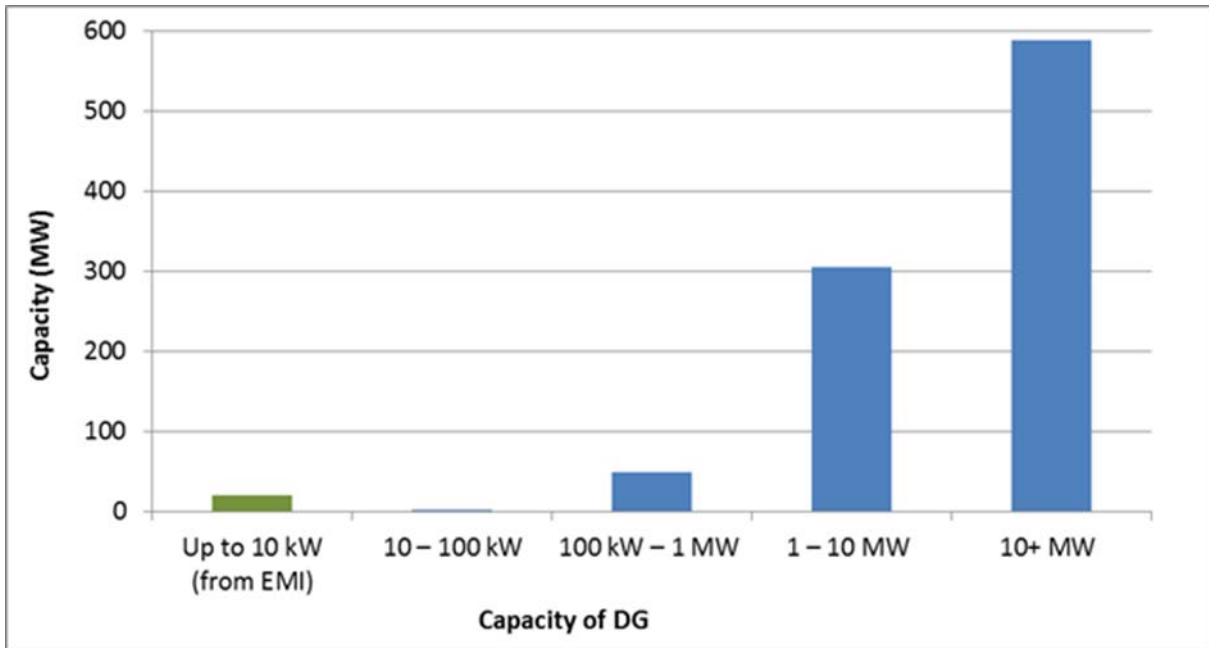
<sup>23</sup> This total excludes notionally embedded generation which is treated like distributed generation in certain respects. See paragraph 3.3.9 and following paragraphs for more information.

Figure 5: Size and types of distributed generation



2.1.6 As Figure 6 shows, most distributed generation is larger-scale plant, with almost 600 MW accounted for by power stations of 10 MW (or 10,000 kW) or more. The ten largest distributed generators account for 443 MW of capacity.

Figure 6: Total capacity of distributed generation plant in each size bracket



## **2.2 Distributed generation uses services provided by networks**

2.2.1 Distributed generation uses services provided by the distribution network to which it is connected, including:

- (a) connection services – the distributor provides dedicated equipment (such as a new power line) to enable the distributed generation to connect to the distribution network<sup>24</sup>
- (b) distribution services – where a distributor has enough capacity in both connection and broader distribution network assets to allow distributed generation to inject electricity into the network up to a maximum capacity.

2.2.2 In addition, distributed generation indirectly uses services provided by the national transmission grid, where the grid conveys power from the local network where distributed generation is located to consumers elsewhere.

2.2.3 In their agreements with distributed generators, distributors often charge for these services together. For example, distributors sometimes recover the upfront cost of connecting to the network as part of the charges for ongoing access.

## **2.3 Distributed generation may also provide services to networks**

2.3.1 The main service distributed generation provides is generating electricity.<sup>25</sup> Distributed generation may also provide network support services if it reduces the cost of operating the network or the need for capital expenditure. Distributed generation may provide network support services to distribution networks and to the transmission network.

- (a) Support services provided to the distribution network may have the effect of allowing a distributor to defer or reduce operating costs or capital expenditure on its network. For example, operating distributed generation may create more spare capacity on the network at a lower cost than alternative investments. This is called avoided cost of distribution (ACOD).
- (b) Support services provided to the transmission network may have the effect of allowing Transpower to defer or reduce operating costs or capital expenditure in relation to the national grid. For example, distributed generation may provide voltage support to the transmission network at a lower cost than alternative investments. This is called avoided cost of transmission (ACOT).

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<sup>24</sup> Provision of connection assets is a contestable service.

<sup>25</sup> Table 2 sets out the various services that distributed generation can provide.



An example of distributed generation providing support services to the transmission network is set out in the case study below.

### **Case study: Kaimai Hydroelectric Power Scheme**

Trustpower's Kaimai Hydroelectric Power Scheme (Kaimai) consists of four power stations in the Wairoa River catchment and has a maximum capacity of about 41MW. It is connected to PowerCo's local distribution network in Tauranga.

The presence of Kaimai, as distributed generation, allows Tauranga's peak demand to be met without Transpower having to upgrade transmission capacity to Tauranga or engage in alternative methods of equalising supply and demand.<sup>26</sup>

Transpower estimates that PowerCo's network in Tauranga has a peak demand of 115MW. In its *2015 Transmission Planning Report*, Transpower forecast that in 2015 Tauranga would have an annual peak demand *at the grid exit point* of 101MW.<sup>27</sup> In addition to this 101MW delivered from the transmission network, Transpower assumes that Kaimai has a minimum generation level of 14MW.<sup>28</sup>

The transmission network serving Tauranga has a winter N-1 rating of 105MW.<sup>29</sup> This capacity is insufficient to serve Tauranga's peak demand of 115MW. By injecting electricity into the Tauranga network, Kaimai makes the transmission network capable of meeting the remaining demand at the peak using existing transmission assets.

- 2.3.2 Where distributed generation provides network support services to distributors or Transpower at a lower cost than the alternatives, savings are passed on to consumers.

## **2.4 Services used and provided will vary**

- 2.4.1 The services distributed generation use will depend largely on how much electricity it generates. For example, a large-scale distributed generation plant on a distribution network (such as a hydro generator) may require the distributor to invest in extra network assets (such as poles, lines and transformers).

<sup>26</sup> For example, load control, demand-side participation or load shedding.

<sup>27</sup> Transpower New Zealand, *2015 Transmission Planning Report - Chapter 10 Bay of Plenty Regional Plan*, Table 10-1, pp141-142.

<sup>28</sup> Trustpower, Kaimai Power Scheme, <https://www.trustpower.co.nz/our-assets-and-capability/power-generation/kaimai>, accessed 11/12/2015.

<sup>29</sup> Transpower New Zealand, *2015 Transmission Planning Report - Chapter 10 Bay of Plenty Regional Plan*, p146.

- 2.4.2 In contrast, for small-scale distributed generation (such as small solar panel installations), most of the electricity generated is likely to be consumed where it is located. Accordingly, there may be little or no change in the distribution services used (although the owner of the distributed generation in that case is likely to be using less energy from the network).
- 2.4.3 The extent to which distributed generation *provides* services to networks depends on how much electricity it produces and on whether the owner of the distributed generation can control when and how much it generates.
- 2.4.4 The output from larger-scale distributed generation is more likely to allow the distributor or Transpower to defer or reduce the need for network investment. However, this depends on where the distributed generation is located, and whether it can generate in periods of greatest need (which coincide with times of peak demand on the network).

## **2.5 Distributed generation has similarities to other network users**

- 2.5.1 The potential for an owner of distributed generation to be both a *user* of network services, and *provider* of services to networks is not unique. Other parties share this characteristic. For example:
- (a) Electricity consumers use distribution services to use electricity.
  - (b) Consumers may also provide services to networks. For example, many consumers allow their distributor to turn water storage heaters down/off remotely. This is a network support service called 'demand response'. In return for providing this service, consumers are rewarded through lower distribution charges.

## **2.6 The DGPPs set default pricing terms for distributors and owners of distributed generation**

- 2.6.1 Part 6 of the Code provides that owners of distributed generation and distributors may negotiate connection contracts for the services each will provide, and the prices that will apply.
- 2.6.2 If they fail to agree terms, or choose not to negotiate a connection agreement, a regulated set of terms will apply.<sup>30</sup> The regulated terms require that prices are determined in accordance with the DGPPs in Schedule 6.4. The DGPPs define the basis for how distributors and owners of distributed generation set the prices of

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<sup>30</sup> See Schedule 6.2 to the Code.

services they each provide. The regulated terms also provide for a dispute resolution process.

2.6.3 The DGPPs require (among other things) that:

- (a) Connection charges for distributed generation must not exceed the incremental costs of providing connection services to the distributed generation.<sup>31</sup>
- (b) Incremental cost is net of transmission and distribution costs that an efficient distributor would be able to avoid by connecting the distributed generation.<sup>32</sup>
- (c) If incremental costs are negative, the distributed generator is deemed to be providing network support services to the distributor, and may invoice the distributor for this service.<sup>33</sup>

## 2.7 Distribution pricing principles are also relevant

2.7.1 One of the Authority's functions is to oversee distribution pricing. The Electricity Commission (the Authority's predecessor) introduced voluntary pricing principles and information disclosure guidelines for distribution pricing in 2010.<sup>34</sup> The distribution pricing principles apply to pricing for all connections to the distribution network, including distributed generation. If the Authority were to remove the DGPPs from the Code, the distribution pricing principles would continue to guide pricing for distributed generation.

2.7.2 The Electricity Commission developed the distribution pricing principles to guide distributors in determining their approach when they set prices and develop their pricing methodologies.<sup>35</sup> The principles are expressed in high-level terms rather than being detailed. The principles encourage distributors to set prices that signal the economic costs of service provision. That is, prices should not involve subsidies, and should signal the effect that providing additional services will have on the cost of the network.

2.7.3 Adoption of the distribution pricing principles is voluntary. However, the Commerce Commission information disclosure regime requires all distributors to disclose the

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<sup>31</sup> Clause 2(a) of Schedule 6.4 to the Code.

<sup>32</sup> Clause 2(a) of Schedule 6.4 to the Code.

<sup>33</sup> Clause 2(e) of Schedule 6.4 of the Code.

<sup>34</sup> The existence of separate pricing principles relating to distribution services (more generally) and distributed generation (in particular) is due to the scope and timing of the former Distributed Generation Regulations 2007. Those regulations regulated only the connection of DG, which is just one class of users of distribution services. The pricing principles for DG are currently included in the Code but pricing principles for distribution in general are not.

<sup>35</sup> The current distribution pricing principles are set out here: <http://www.ea.govt.nz/dmsdocument/14453>.

extent to which their pricing methodologies are consistent with the distribution pricing principles. The Authority undertakes periodic reviews to evaluate how closely distributors' pricing methodologies align with the pricing principles issued by the Authority.

- 2.7.4 The reviews enable the Authority to assess distributors' progress towards alignment over time.
- 2.7.5 The distribution pricing principles are voluntary and high-level because each of the 29 distributors in New Zealand faces different circumstances. For example, some distributors face strongly growing demand that drives network investment, while others have static or falling demand and little need for new investment. The Authority's view is that distributors have strong incentives to move towards service-based and cost-reflective pricing structures.<sup>36</sup>
- 2.7.6 The Authority is currently reviewing the pricing of distribution services, and the implications of evolving technologies.<sup>37</sup> As part of its review, the Authority is considering whether the distribution pricing arrangements, including the voluntary distribution pricing principles, encourage distributors to adopt service-based and cost-reflective pricing.

## **2.8 The Commerce Act regime applies to distributed generation and distributors**

- 2.8.1 The Commerce Act 1986 regulates distribution revenue in New Zealand by setting 'price-quality paths' for seventeen distributors and Transpower.<sup>38</sup> The regulation is administered by the Commerce Commission and is intended to ensure that (among other things) network owners:
- (a) cannot extract excessive profits
  - (b) have incentives to innovate and operate efficiently.

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<sup>36</sup> Chapter 5 of the Authority's paper "Transmission Pricing Methodology – second issues paper" gives a full explanation of why prices need to be service-based and cost-reflective. Incentives and constraints are discussed in para 7.5.2 of the Authority consultation paper 'Implications of evolving technologies for pricing of distribution services' which is available at <http://www.ea.govt.nz/dmsdocument/20057>.

<sup>37</sup> See <http://www.ea.govt.nz/development/work-programme/transmission-distribution/distribution-pricing-review/consultations/#c15642>.

<sup>38</sup> Transpower is subject to a revenue cap, and the seventeen distributors are subject to weighted average price caps. Distributors that meet the consumer ownership criteria under section 54D of the Commerce Act are exempt from price control. All networks are subject to information disclosure regulation. <http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/electricity-distribution/>

2.8.2 In relation to distributed generation, price-quality regulation provides that:

- (a) Transpower can enter into arrangements with owners of distributed generation to procure 'non-transmission services', ie, substitutes for conventional transmission services. The regime provides incentives for Transpower to procure non-transmission solutions where it would be more efficient than investing in transmission assets. Appendix C explains the regime further.
- (b) For each distributor subject to price-quality regulation, the distributor can recover from its customers the cost of ACOT payments made to owners of distributed generation if the payment is "made in accordance with ... Schedule 6.4 of Part 6 of the Electricity Industry Participation Code or the Electricity Industry Act 2010".<sup>39</sup> The distributor can recover the cost of 'notional' ACOT payments made to notionally embedded generators in the same way.
- (c) Accordingly, if a price-regulated distributor has contractually agreed to make ACOT payments to an owner of distributed generation, such payments are recoverable, provided the contractually agreed terms comply with the DGPPs in Schedule 6.4.

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<sup>39</sup> Electricity Distribution Services Input Methodologies Determination 2012

### **3. The DGPPs do not promote efficiency**

#### **3.1 There are two problems with the DGPPs**

3.1.1 The Authority has identified two problems with the pricing arrangements for distributed generation in Part 6 of the Code, and in particular the DGPPs in Schedule 6.4.

- (a) Owners of distributed generation are not required to pay a share of the common costs of providing distribution services. The costs are borne by other network users – in particular, by consumers. The DGPPs mean distributors are less able to adopt service-based and cost-reflective pricing.
- (b) The DGPPs reward owners of distributed generation for avoided transmission *charges*, rather than signalling the true value of any transmission-related services provided or used by distributed generation. This is because, for distributors, transmission costs are the transmission charges they pay. This encourages inefficient investment in distributed generation. It also encourages inefficient operation of distributed generation, and distorts competition in favour of distributed generation compared to alternatives.

#### **3.2 Distributed generation owners do not pay common costs Prices should promote efficiency**

3.2.1 Prices convey information to producers and users of goods and services. Prices therefore influence production and consumption decisions, and affect whether consumers and producers use resources to generate the greatest possible total benefit to society. This is also known as maximising overall efficiency.

3.2.2 To promote efficiency, network prices should be service-based and cost-reflective. This means that they should at least recover the incremental costs of the service. Incremental costs are the additional costs of providing a customer or group of customers with new or additional services.<sup>40</sup> Provided prices are not below incremental cost, customers will have incentives to take into account the additional costs they impose on the network.

3.2.3 However, pricing based on incremental cost alone does not necessarily maximise overall efficiency in all situations. If distributors price all their services at the incremental cost of providing the services, they would generally not be able to

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<sup>40</sup> Incremental cost includes fixed capital costs. In particular, customers who benefit from the services of any new investment should pay the full cost of that investment.

cover all their costs. This is because networks typically have a large proportion of costs that do not vary with how much of a service or how many services they provide and are not attributable to any one activity of the business. These are called “fixed and common costs” and include some network costs as well as overheads like head office salaries.<sup>41</sup>

- 3.2.4 If distributors did not receive any revenue to cover these common costs, they would not recover the full costs of constructing and maintaining the network. That would undermine the incentive to invest in distribution networks, creating what is known as dynamic inefficiency.
- 3.2.5 To avoid dynamic inefficiency, distributors generally need to charge prices that exceed incremental costs. If a distributor sets prices that are too high, however, users may look for other ways to obtain an equivalent service. For example, instead of using the distributor's services, a network user might invest in its own line, and bypass the distribution network. The cost of a consumer obtaining electricity by an alternative means is termed the standalone cost.
- 3.2.6 To promote overall efficiency, the prices of distribution services should at least cover the incremental cost of that service and not exceed the standalone cost. Within this range, prices should be set to recover common costs in a way that causes the least possible distortion to behaviour, and hence minimises efficiency losses.

### **Pricing principles for connection services do not promote efficiency**

- 3.2.7 As noted above at 2.6, the DGPPs state that connection charges for distributed generation “must not exceed the incremental costs for providing connection services”.<sup>42</sup> In this context, “connection services” covers the full range of network services *used* by the distributed generation, and the services *provided* by distributed generation. In particular, incremental costs include not just the cost of the initial connection, but also the ongoing costs of providing services to distributed generation that allow distributed generation to remain connected to the network.<sup>43</sup>
- 3.2.8 The DGPPs do not promote efficiency because they make incremental cost the upper limit for charges paid by distributed generation for connection services. Because “connection services” includes distribution services provided to distributed generation, this means owners of distributed generation are not required to pay a share of common network costs. At least, they are not required

<sup>41</sup> In this paper, these costs will be referred to simply as “common costs”.

<sup>42</sup> Schedule 6.4, section 2(a) of the Code.

<sup>43</sup> There is a further discussion of services in section 2.

to pay such costs in their capacity as owners of distributed generation as defined under the Code.<sup>44</sup> Instead, these costs must be borne entirely by other network users – in particular, electricity consumers.

- 3.2.9 While it may be efficient for owners of distributed generation not to pay common costs in some situations, it is unclear why this would be efficient in all cases. Further, charging distributed generation owners based solely on incremental costs in all cases is likely to understate the longer run cost of providing distribution services to distributed generation.<sup>45</sup> This is likely to encourage inefficient investment in distributed generation, and inefficient operation of distributed generation.
- 3.2.10 It is most efficient for distributors to allocate common costs in a way that causes the least possible distortion to behaviour but with the caveat that those prices are set in ways that avoid distorting production and investment decisions. This approach minimises overall efficiency losses and maximises ‘the size of the economic pie’. This means allocating a relatively high proportion of common costs to those customers who are less likely to alter their investment, production or usage in response to higher prices.
- 3.2.11 The Authority has not established whether owners of distributed generation are always more or less price-responsive than other customers, as that will depend on individual circumstances. However, it would likely be efficient for distributed generation owners to bear at least some share of common costs.
- 3.2.12 The DGPPs prevent distributors from allocating common costs to owners of distributed generation. This can cause consumers or owners of distributed generation to make inefficient decisions about investment or usage. For example:
- (a) A consumer who pays a greater share of common costs than they otherwise would might use the network less (even if they value usage more highly than the cost to society).
  - (b) An investor might be encouraged to invest in distributed generation because it will pay no common costs – even if the distributed generation has a relatively high cost (compared with the equivalent amount of grid-connected generation).
- 3.2.13 Finally, the DGPPs will apply if a distributor and a distributed generation owner do not agree terms of a connection contract. This means that owners of distributed

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<sup>44</sup> A distributed generation plant may also have load associated with it – in which case the owner will presumably be paying distribution charges in its capacity as a consumer, and these will include contributions to common costs. However, as shown in Figure 6, larger scale distributed generation plant accounts for the great majority of installed capacity. For these larger plants, the ‘generation’ aspect of the installation is likely to dominate any consumption at the installation.

<sup>45</sup> On the basis that networks need to recover common costs over the longer run, otherwise investment will not be viable.



generation can refuse to agree terms with the distributor, thereby ensuring that the default terms (which do not require them to pay common costs) apply.

### **This problem affects allocation of \$1 billion in network costs**

- 3.2.14 Because of their inherent physical characteristics, distribution networks typically have a high proportion of common costs. For example, Vector's distribution pricing methodology acknowledges that *'the majority of costs to be recovered are shared costs, which cannot be specifically attributed to particular consumer groups except at high levels of aggregation'*.<sup>46</sup>
- 3.2.15 Altogether, regulated distributors had a reported revenue allowance of approximately \$1.9 billion for distribution services in the year to March 2014.<sup>47</sup> This allowance is to compensate distributors for their total distribution costs (including a regulated rate of return). Based on common costs being the majority of distribution costs, this implies that around \$1 billion dollars per annum of distributor costs would be common costs. Applying the DGPPs, none of this would be recoverable from distributed generators as network users. Instead, all of the common costs would be borne by electricity consumers.
- 3.2.16 It may be efficient to recover a very high proportion of common costs from electricity consumers rather than owners of distributed generation (if doing so is the least distortionary allocation). Distributed generators may provide services to distributors in some instances, and should be paid by distributors, rather than having to pay.<sup>48</sup>
- 3.2.17 However, it seems unlikely that this type of situation applies universally to distributed generators. The information from the August 2015 survey of distributors tends to support this view. It indicates that a very small proportion of distributed generators receive any payment for providing ACOD services.
- 3.2.18 These factors suggest that there is potential for efficiency losses to arise by precluding any common cost recovery from distributed generation owners.

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<sup>46</sup> Vector's electricity distribution pricing methodology from 1 April 2015, page 16.  
<https://vector.co.nz/disclosures/electricity/pricing-methodology>

<sup>47</sup> Source: 2014 Information Disclosure Compendium, published by PWC: 'Line Charge Revenue' reported for all distributors (excluding recovery of transmission charges).

<sup>48</sup> In other words, the presence of distributed generation reduces rather than increases the need for investment in distribution assets.

### **3.3 The DGPPs fail to encourage distributed generation to reduce transmission costs**

#### **DGPPs reward distributed generation for avoided transmission charges**

- 3.3.1 Distributed generation can affect transmission costs. To promote efficiency, any payments made to (or by) distributed generation should reflect any benefits (or costs) in terms of transmission costs. The DGPPs do not achieve this.
- 3.3.2 Distributed generation can reduce, increase, or have no effect on transmission costs, depending on the circumstances. Locating distributed generation in a region that imports energy may defer the need for grid upgrades, and therefore reduce transmission costs.<sup>49</sup> Conversely, adding distributed generation in a region that exports energy may not reduce transmission costs, and may even increase costs if it requires more investment in the grid.
- 3.3.3 To promote overall efficiency, any payments made to (or by) distributed generation need to reflect any transmission-related effects (either benefits or costs). Then owners of distributed generation can consider these effects when deciding how to invest in and operate plant.
- 3.3.4 The DGPPs do not achieve this. Instead, they require distributors to signal to distributed generators the avoided/additional transmission *charges* the distributor would otherwise pay in the absence of distributed generation.<sup>50</sup>
- 3.3.5 Transmission charges are the cost of transmission to the distributor. These avoided or additional charges do not necessarily reflect the avoided or additional transmission costs. As a result, there can be over-signalling or under-signalling of transmission costs and benefits.

#### **Poor signalling of transmission-related effects has inefficient results**

- 3.3.6 The following effects can result from over-signalling of transmission-related benefits associated with distributed generation:
- (a) Distributed generators may operate at times when the incremental running costs exceed any benefit from reduced or deferred transmission investment costs.

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<sup>49</sup> This assumes that distributed generation will be operating during the periods that drive the need for additional transmission capacity.

<sup>50</sup> In respect of transmission-related effects, the *charges* are the relevant issue because Schedule 6.4 requires each distributor to consider the transmission costs that it would avoid as a result of the connection of the distributed generation. And for distributors, transmission costs predominantly means transmission charges.

- (b) Distributed generation that does not reduce or defer transmission investment costs may be retained, even though the incremental retention cost exceeds any transmission benefit.
- (c) Investment in new distributed generation may be made, or located, based on a transmission *charge* signal, while the transmission-related benefits are non-existent or even negative.

3.3.7 These effects would result in efficiency losses, because the cost of actions to reduce or defer transmission investment will exceed the real benefit of that activity.

3.3.8 The current DGPPs could also lead to under-signalling of transmission related benefits of distributed generation. In these cases, the opposite effects from those listed in paragraph 3.3.6 could occur. This would also create efficiency losses.<sup>51</sup>

### **DGPPs may encourage inefficient investment in notionally embedded generation**

3.3.9 The DGPPs only apply to distributed generation (ie, generation physically connected to distribution networks). However, they may also affect decisions about investing in and operating notionally embedded generators.

3.3.10 Notionally embedded generators are connected to the grid. However, Transpower has agreed with the owners of such generation plant, following detailed assessment, to calculate transmission charges *as if* the generation plant was connected to the distribution network and not to the grid. Transpower has agreed to such an arrangement in order to retain the notionally embedded generator as a directly connected customer. Otherwise, there would be uneconomic bypass of the transmission grid. This is because the owner of the generator would be better off financially if the generation plant physically bypassed the grid.

3.3.11 The Authority understands that distributors typically treat the resulting transmission charge discount as a 'notional' ACOT amount, and pay some or all of it to the owner of the notionally embedded generator.

3.3.12 The Authority understands that the Commerce Commission treats such payments as a recoverable cost for price-regulated distributors, provided the payments comply with the default DGPPs in Schedule 6.4 of the Code. Figure 7 below shows ACOT payments made by price-regulated distributors.

3.3.13 Note that the prudent discount policy in Schedule 12.4 of the Code has now replaced notional embedding.<sup>52</sup> However, the effects are the same with respect to

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<sup>51</sup> This risk might be mitigated in practice by distributed generation contracting directly with Transpower, using the mechanisms discussed in paragraph 4.2.19.

<sup>52</sup> The Authority expects that some notional embedding contracts signed before the prudent discount policy was put in place have not yet expired.

the ACOT issue. Under both notional embedding and the prudent discount policy, generators will receive payments for reducing transmission charges (equivalent to ACOT payments). In this paper, we use the term “notionally embedded generator” to include generators that contract with Transpower under the prudent discount policy.

- 3.3.14 The existence of the DGPPs means that notionally embedded generators receive payments equivalent to ACOT. Thus, the DGPPs may also encourage inefficient investment in and operation of grid-connected generation that is notionally embedded (including those that receive a prudent discount).

### **Avoided transmission charges have increased substantially**

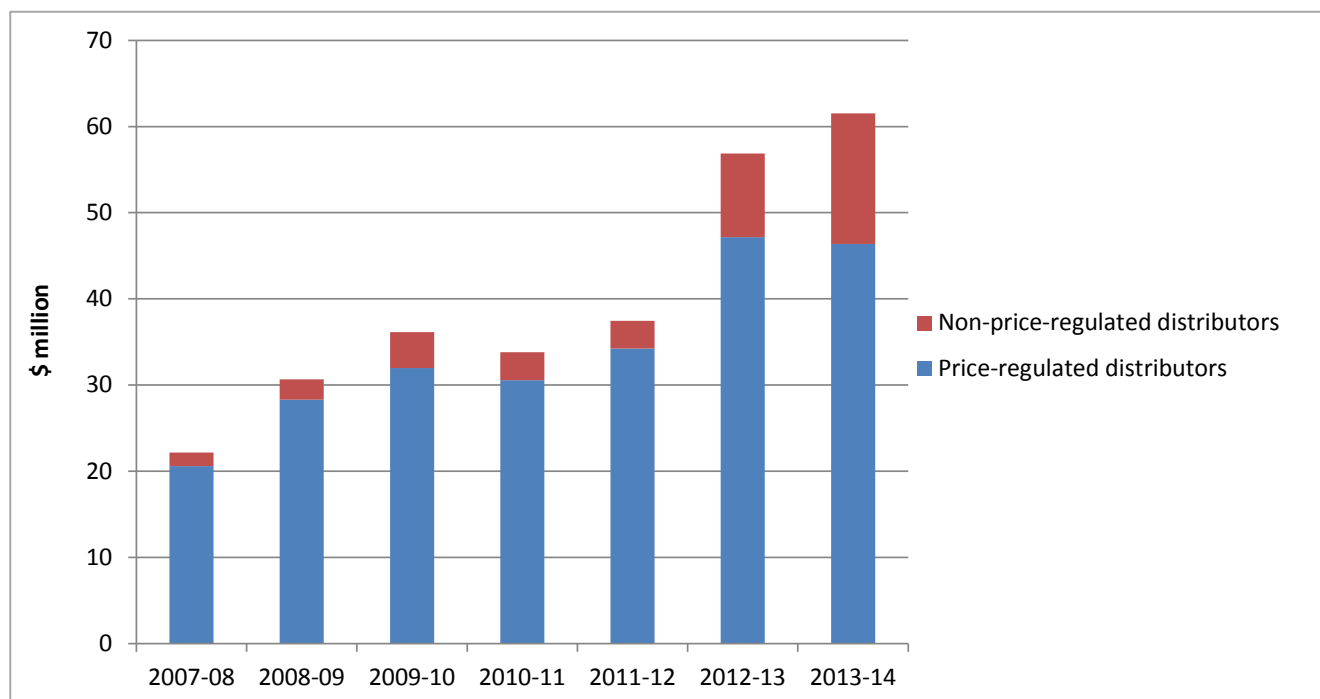
- 3.3.15 For the year ended March 2014, distributors reported \$62 million for “avoided transmission charges”, based on disclosures to the Commerce Commission. The Authority expects that distributors would have paid most of this sum to owners of distributed generation and notionally embedded generation in the form of ACOT payments.<sup>53</sup>
- 3.3.16 As Figure 7 shows, the allowance for avoided transmission charges nearly tripled over the six years to 2014. This coincides with substantial expansion of transmission capacity, which the Authority would generally expect to reduce the benefit of investing in distributed generation. For example, the Commerce Commission has approved \$2.8 billion worth of major transmission investment since 2004. Further, Transpower’s regulatory asset base is expected to have increased by 77% between 2011/12 and 2015/16.<sup>54</sup>

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<sup>53</sup> The Authority understands that most of the \$62 million was for payments to distributed generation and notionally embedded generators. However, it also includes allowances for instances where distributors purchased an asset from Transpower. Prior to 2015, the information disclosures did not distinguish between avoided transmission charge allowances for distributed generation and purchased assets. Purchases of assets from Transpower reduce the transmission charge for the relevant distributor. The purchased assets are rolled into the value of the regulatory asset base of the distributor, and treated as any other asset. As an incentive for such purchases, price-regulated distributors receive a recoverable cost equal to their avoided transmission costs for a period of 5 years from and including the year in which the assets are acquired. It is not possible to separately identify the purchased asset component of avoided transmission costs from the public information disclosures. However, the Authority understands these to be a relatively modest proportion of the total allowance. This inability to separate the purchased asset component of avoided transmission costs applied up to and including the 2013/14 disclosure (after which they are disclosed separately).

<sup>54</sup> Transpower’s opening regulatory asset base (“RAB”) is expected to increase from a value of \$2,606.7 million in 2011/12 to an expected value of \$4,610.2 million in 2015/16. Source: Transpower annual regulatory reports, 2011/12 and 2013/14. Note that comparing the two RABs understates the impact of investments on the RAB because the 2015/16 RAB does not incorporate all major capex investments that have been approved since 2004. Further, the impact of the new investment is understated because existing assets in the RAB depreciate, meaning that without any capital investment, the RAB would be expected to decrease from year to year.

Figure 7: Cost allowance for 'avoided transmission charges'

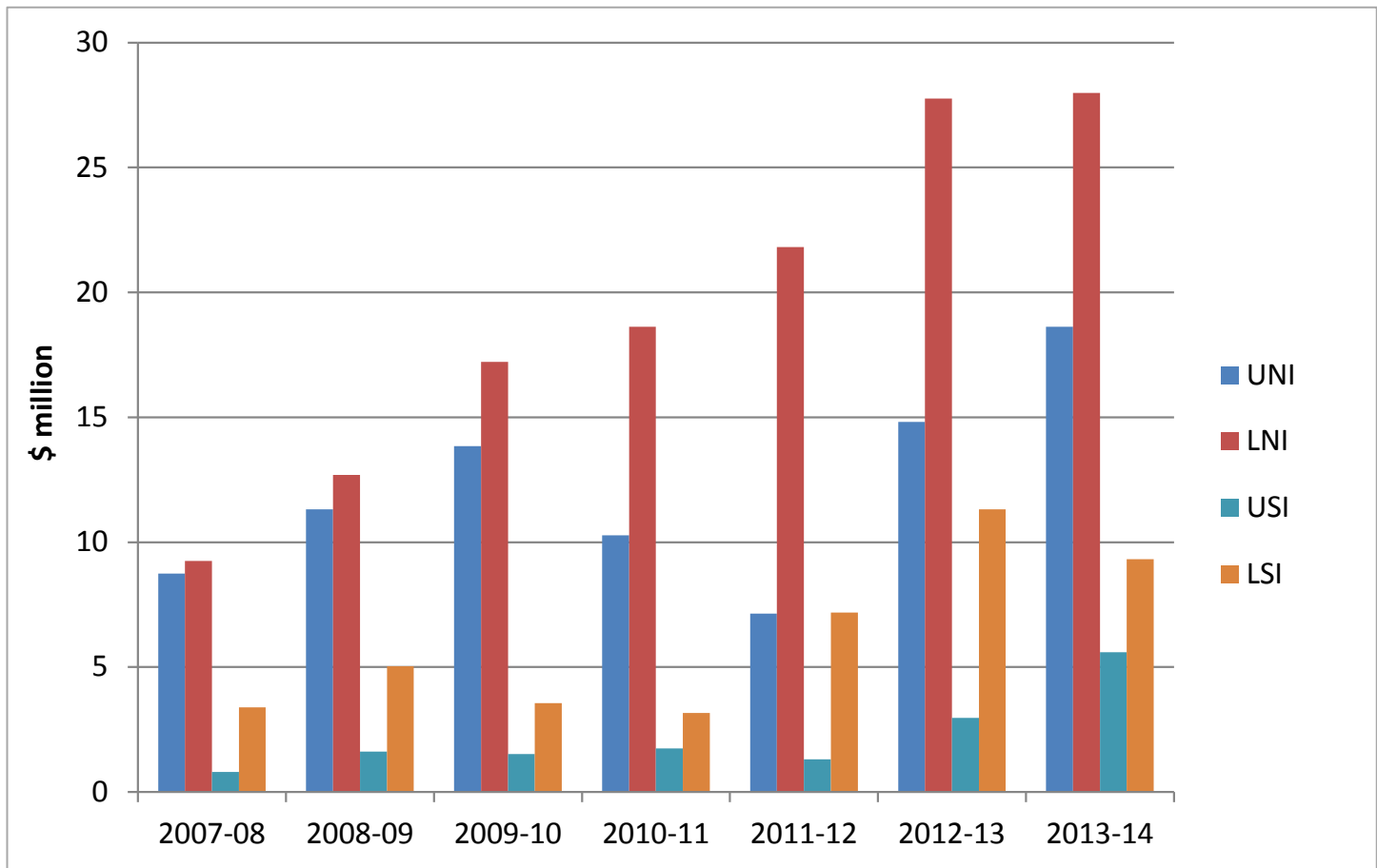


3.3.17 Of the total avoided transmission charge allowance, approximately 80% belongs to distributors subject to price-quality regulation. Information on the split between distributed generation and notionally embedded generators is less clear-cut, but the Authority estimates that it was approximately 50:50 in 2013/14.

3.3.18 Figure 8 shows the breakdown of the allowance by transmission region.<sup>55</sup> In absolute terms, around \$25 million of the growth in the allowance during the illustrated period is associated with the LSI and LNI regions. Further, of the total \$62 million allowance in 2014, approximately \$37 million (60%) related to the LSI and LNI. For completeness, Figure 8 also shows the amounts relating to the USI and UNI regions. The share of the allowance (and the growth) associated with the USI and UNI is lower than the share of the LSI and LNI.

<sup>55</sup> The regional breakdown is based on matching distributor areas to the regions used for calculating regional coincident peaks for transmission charging, noting that the boundaries are not exactly aligned in some cases.

Figure 8: Cost allowance for 'avoided transmission charges' by region



3.3.19 The Authority expects that the actual avoidable cost of transmission in the LNI and LSI has generally been relatively low or nil, because there is spare transmission capacity available.

3.3.20 This information suggests that a large proportion of ACOT payments (possibly most) provide little or no benefit in terms of deferral of transmission costs. At a minimum, it is highly questionable whether the growth over six years of approximately \$25 million in annual ACOT payments in the lower South Island and lower North Island yields worthwhile transmission benefits.

3.3.21 Instead, it is likely that consumers are paying an extra cost of around \$25 million – \$35 million<sup>56</sup> per annum without receiving an associated benefit.<sup>57</sup> This transfer

<sup>56</sup> The lower estimate is based on the growth in ACOT payments in the lower South Island and lower North Island between 2008 and 2014. The higher estimate is based on the view that most of the total ACOT payments in these regions (\$37 million in 2014) are not providing a transmission-related benefit.

<sup>57</sup> While distributors that pay ACOT receive an offsetting credit on their individual transmission charges, because Transpower is subject to an overall revenue cap, it will be expected to reallocate charges among its customers to make up for such 'lost' revenue (ie, any ACOT payments that do not genuinely reduce transmission costs). Accordingly, in

from consumers to some owners of distributed generation and notionally embedded generation creates efficiency losses. These arise because the payments encourage inefficient investment or operation of distributed generation and notionally embedded generation, and reduce allocative efficiency. Appendix D contains a further discussion of these issues.

### **The TPM review is relevant**

- 3.3.22 The inefficiencies described in paragraph 3.3.6 are influenced by the degree of misalignment between transmission charges and transmission costs. Under the current TPM, which determines how Transpower allocates transmission charges among customers, the degree of misalignment can be substantial.
- 3.3.23 The Authority is currently reviewing the TPM, and considers that there is potential for alternative options to the current TPM to better promote the Authority's statutory objective. Specifically, the Authority considers that the TPM could be more dynamically efficient by better promoting efficient investment, ensuring lowest cost development of transmission and other electricity assets over time. These dynamic efficiency gains would benefit electricity consumers in the long-term.
- 3.3.24 If a new TPM results from the review, the new TPM is likely (among other things) to reduce the misalignment between transmission charges and costs.
- 3.3.25 However, it is not certain that the review will lead to a change to the TPM, so the Authority has also considered a hypothetical scenario where the TPM remains the same (including the changes resulting from Transpower's recent operational review). Further, any change to the TPM would take some years to implement. Even with a change to the TPM, it is unlikely that transmission charges and costs will align in all situations.
- 3.3.26 There may also be practical difficulty in applying the concept of an 'avoided transmission charge', depending on the nature of any change to the TPM. This is because it may be difficult for distributors and owners of distributed generation to assess the effect of individual distributed generation plants on transmission charges.
- 3.3.27 For these reasons, a new TPM alone is unlikely to address fully the problems listed in paragraph 3.3.6.

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overall terms, customers are expected to pay the sum of the ACOT allowances plus the transmission charges required for Transpower to reach its revenue cap.

## **4. Regulatory statement for proposed Code amendment**

### **4.1 The Authority proposes to remove the DGPPs from the Code**

4.1.1 The Authority proposes to address both the connection services issue and the ACOT issue by removing the DGPPs from Part 6 of the Code.

4.1.2 The proposed Code amendment would:

- (a) remove Schedule 6.4, and hence, the DGPPs
- (b) remove clause 19 of the regulated terms in Schedule 6.2. This clause refers to the DGPPs in Schedule 6.4
- (c) remove clause 4 of Schedule 6.3. This clause says the Rulings Panel must apply the pricing principles to resolve disputes under Part 6.
- (d) include transitional provisions
- (e) make some consequential drafting changes to Part 1 and Part 6.

4.1.3 The proposed Code amendment is set out in Appendix B.

#### **The proposal would address the connection services issue**

4.1.4 Under the proposal, distributors would no longer be required (by the DGPPs) to treat distributed generation on a preferred basis when they set charges for distribution services. This would better allow distributors to adopt service-based and cost-reflective charging structures across all users of distribution networks, including owners of distributed generation. Under the proposal, incremental cost would no longer be the upper limit for charges paid by owners of distributed generation for connection services. As a result, owners of distributed generation could be required to pay a share of common network costs, in common with other network users.

4.1.5 One aim of the distribution pricing principles is that distribution prices should signal the economic costs of providing distribution services. Prices should not involve subsidies. That is, prices should be equal to or greater than incremental cost, and less than or equal to standalone cost. Prices should be set having regard to available capacity on the network, and should signal the impact of additional consumption on the cost of investment in the network.

4.1.6 The Authority considers that a separate set of pricing principles for distributed generation are not required to ensure that pricing for distributed generation



connection services is efficient. The Authority is currently reviewing the distribution pricing principles.<sup>58</sup>

- 4.1.7 The Authority proposes to remove access to the Rulings Panel for pricing disputes between owners of distributed generation and distributors. This is consistent with the proposed removal of the DGPPs and the resolution of the connection services issue, since it leads to consistent rules for distributed generation and other network users. Access to the Rulings Panel for pricing is not required for distributed generators. Distributors that are subject to price control (which the Commerce Commission uses to control monopoly profits) would not benefit from charging any individual distributed generator an excessive price. Distributors not subject to price control are likely to have commercial incentives to keep prices down. Consumers do not have recourse to the Rulings Panel on pricing matters. The proposal means distributors would treat all classes of network user alike.
- 4.1.8 Part 6 provides a set of default terms, called regulated terms. The regulated terms apply if the distributed generator and distributor do not agree terms. The regulated terms include the default pricing terms in Schedule 6.4. Removing Schedule 6.4 would remove the default price terms for distributed generators but the other regulated terms would remain in place.

### **The proposal would address the ACOT issue**

- 4.1.9 The proposal means that distributors would not have to consider the effect on transmission charges when setting connection charges for distributed generation.
- 4.1.10 Where distributed generation provides a service that is a genuine substitute for a transmission service, Transpower and distributed generators can reflect this in their agreements.<sup>59</sup>
- 4.1.11 The proposed Code amendment would leave Transpower solely responsible for obtaining and paying for any transmission-substitute services distributed generators provide. This is appropriate because Transpower is best able to assess the value of those services. The Authority expects that this shift would address the ACOT issue and promote efficiency, for reasons described in the next section.

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<sup>58</sup> See <http://www.ea.govt.nz/development/work-programme/transmission-distribution/distribution-pricing-review/> .

<sup>59</sup> The existing regulatory framework already provides for such agreements (see section 4.2 for more detail).

## 4.2 Shifting responsibility for ACOT to Transpower would promote efficiency

4.2.1 Shifting responsibility for determining ACOT from distributors and distributed generation owners to Transpower would promote the Authority's statutory objective, for the reasons set out below.

4.2.2 The Code does not currently promote efficient outcomes in this area because:

- (a) **Information is not available:** distributors and distributed generators do not often have the best information and analytical tools to assess how distributed generation affects transmission costs. Transpower is the best party to do that. Even if the Code were changed so that ACOT payments were based on avoided cost rather than avoided charges, this information availability problem would still prevent the outcome from being efficient.
- (b) **The incentives are wrong:** there is an incentive for distributed generators to over-estimate the benefits of distributed generation for transmission. However, there is no countervailing incentive for distributors to negotiate lower ACOT payments, because they pass the costs on to consumers. Even where consumers and distributors have the same interests, a distributor's incentive will be to minimise transmission charges, rather than transmission costs. This is because the DGPPs reward distributors for reducing transmission charges.
- (c) **The default provisions are inappropriate:** the default terms require distributed generators to receive a credit based on the avoided transmission *charges* (ie, the avoided charge) rather than the avoided actual resource *cost*. There is no assessment of the real impact of distributed generation on transmission costs.

4.2.3 Under the new proposal, Transpower will pay for distributed generation that reduces or defers transmission costs. Transpower will do this because the Commerce Act 1986 provides incentives for it to provide a defined level of transmission service at the lowest possible cost. In addition, Transpower will no longer be able to rely on distributors making payments to owners of distributed generation for avoided transmission costs, as distributors will no longer be compensated for doing so. In other words, the role of paying distributed generators for avoided transmission costs would largely pass from distributors to Transpower.

## Distributors will not assess avoided transmission charges or make ACOT payments

- 4.2.4 This subsection sets out how the proposed Code amendment would reduce the extent to which distributors would be required to assess the amount of avoided transmission charges/costs and make ACOT payments.
- 4.2.5 The current DGPPs require distributors to assess how the distributed generation on their network affects transmission *charges*. If distributed generation reduces transmission charges, the distributor must pay the distributed generator. If the distributed generation increases transmission charges, payment flows in the other direction.
- 4.2.6 Under the current TPM, distributed generators do not generally make transmission-related payments to distributors, because distributed generation does not increase the transmission charges the distributor pays.<sup>60</sup> Instead, distributors pay distributed generators in the form of ACOT payments.
- 4.2.7 The proposed Code amendment could reduce ACOT payments in several different ways:<sup>61</sup>
- (a) Where the regulated terms apply, avoided transmission costs or charges would not be included in the calculation of payments between distributors and distributed generators.
  - (b) Where the regulated terms do not apply, the proposal could still have its intended effect, as it could influence the terms of future connection contracts agreed between distributors and distributed generators. This is because the Authority anticipates that parties would tend to align such contracts with the DGPPs, if the DGPPs were to continue to exist.
  - (c) Distributors subject to price-quality control could not recover the cost of ACOT payments from their customers. Distributors subject to price-quality control can recover ACOT payments under the Commerce Commission's current price-quality control arrangements (which run until 31 March 2020). The proposal would remove this ability because the 'distributed generation allowance' means they can only recover amounts payable or receivable 'made in accordance with (a) Schedule 6.4 of Part 6 of the Code (ie, the

<sup>60</sup> It is possible that a South Island distributed generator could cause its distributor to incur a HVDC charge that exceeded the reduction that the distributed generation brought about in the distributor's interconnection charge – although this situation is unlikely under the new MWh allocator of the HVDC charge (which is to be used to set transmission prices to apply from 1 April 2017). In this situation, there might be a case for the distributed generation to make ACOT payments to the distributor.

<sup>61</sup> In this context, and for the balance of this section, 'ACOT payments' includes payments to distributed generation and to notionally embedded generators.

DGPPs), or (b) the Electricity Industry Act 2010'. ACOT payments would no longer be in accordance with the DGPPs because the DGPPs would not exist. The Authority anticipates that if distributors could not recover the cost of making ACOT payments they would stop making ACOT payments, if their contracts allowed them to.

4.2.8 The Authority understands that distributors that are subject to price-quality control currently pay around 80% of ACOT (by value).

4.2.9 If distributors stopped making ACOT payments to distributed generation owners and notionally embedded generation this would be an efficient outcome. However, distributed generation and notionally embedded generation should still be:

- (a) paid for the transmission services they provide
- (b) charged for the transmission services they use.

**Distributed generation owners will still be paid for the services they provide, and pay for the services they require**

4.2.10 This subsection sets out how, even without ACOT payments from distributors, distributed generators could still be paid for the transmission benefits they provide and pay for the transmission costs they create.

4.2.11 Table 2:

- (a) sets out services that distributed generators can provide, and how they could be paid for the services, if distributors stop making ACOT payments
- (b) sets out services that distributed generators may require, and how they could pay for the services, if distributors stop making ACOT payments.

4.2.12 Table 2 is not restricted to *network* services; it also includes other types of services associated with distributed generation, such as export and sale of energy. However, the connection contract between the distributor and owner of distributed generation is not the correct vehicle to recover benefits and costs of non-network services.

4.2.13 Some effects of distributed generation, which some parties say are beneficial, are not included in the table because the Authority does not consider they are true economic benefits. These include:

- (a) reducing wholesale prices at system peak times
- (b) reducing wholesale prices in the local area by mitigating transmission constraints.

The Authority considers that a reduction in *prices*, in itself, is a wealth transfer rather than an economic benefit. (Reducing wholesale costs at peak times or in a local area, however, is a true economic benefit and is included in the table below.)

Table 2: Services that distributed generation can provide, and services that distributed generation can require

<b>Type of service</b>	<b>How the benefit or cost of service could be passed on to the distributed generation owner</b>
<i>Network services</i>	
Avoided cost of transmission	<p>Transpower can contract for investment in and/or operation of distributed generation that efficiently reduces or defers transmission network costs.</p> <p>TPM and the transmission charge structure is also relevant. (See next subsections for more discussion).</p>
Connection	<p>Distributors could still recover from distributed generation owners the costs incurred by the distributor for the initial connection of distributed generation to their network.</p>
Avoided cost of distribution	<p>Where applicable, distributors could still make ACOD payments to distributed generation owners where the operation of the distributed generation reduced distribution network costs, and vice versa.</p> <p>At present, few distributors pay ACOD. A substantial proportion of distributors responding to the Authority's recent survey indicated that they consider that distributed generation does not reduce their distribution network costs.</p>
Improved local reliability of supply – eg, distributed generation can allow supply to be maintained during a planned or unplanned local network outage	<p>Distributors subject to price control under the Commerce Act must meet a defined reliability standard to avoid a potential liability for breaches. They will continue to have an incentive to use/contract with distributed generation owners to promote attainment of these standards, where distributed generation offers the most efficient solution.</p> <p>For distributors not subject to price control under the Commerce Act, the alignment between distributor, customer, and owner interests is intended to ensure that distributed generation will be used/contracted with, where distributed generation provides the least cost means to attain the desired level of reliability.</p>

Type of service	How the benefit or cost of service could be passed on to the distributed generation owner
<i>Non-network services</i>	
Providing energy	Distributed generation owners receive payment for their energy production, either directly through the wholesale electricity market or indirectly via a contract outside the wholesale market.
Intermittency	The wholesale electricity market should signal the cost of intermittency.
Providing capacity, and hence supporting reliability, at peak times	To the extent that distributed generation provides capacity at peak times, it should be able to obtain a reward through the wholesale electricity market (as spot market prices are often higher at peak times) or through a contract.
Reducing the costs associated with congestion by mitigating local transmission constraints	To the extent that distributed generation mitigates local transmission constraints, it should be able to obtain a reward through the wholesale electricity market.
Providing ancillary services	Ancillary service markets are intended to deliver the appropriate incentives for provision of ancillary services.
Altering network losses	<p>The price paid to generators for their energy production generally reflects marginal losses.</p> <p>However, neither grid-connected generators nor owners of distributed generation:</p> <ul style="list-style-type: none"> <li>• receive payment for loss reduction, where their operation reduces the overall cost of network losses (relative to a counterfactual in which they do not operate)</li> <li>• pay for increasing losses, where their operation increases the overall cost of network losses (relative to a counterfactual in which they do not operate).</li> </ul>

Type of service	How the benefit or cost of service could be passed on to the distributed generation owner
Retail market competition benefits – ie, distributed generation investment in a region subject to locational price risk, by a party other than the main generator in that region, can support more retailers to compete in the local retail market	Such distributed generation investment can be incentivised: <ul style="list-style-type: none"> <li>• through the retail market, if the distributed generation investor is also a retailer that wishes to compete in the region, or</li> <li>• through the contract market, otherwise.</li> </ul>

4.2.14 Table 3 sets out services that distributed generators may provide that relate to matters outside the Authority’s statutory objective. These effects are included because they are relevant considerations for other policy makers and stakeholders. Table 3 also sets out how owners of distributed generation could be incentivised to provide such services, if distributors stop making ACOT payments.

Table 3: Services that distributed generation can provide relating to matters outside the Authority’s statutory objective

Type of service	How the benefit or cost of service could be passed on to the distributed generation owner
Reducing greenhouse emissions	The Emissions Trading Scheme is the primary mechanism designed to incentivise generators to reduce greenhouse emissions.
Providing renewable energy	The New Zealand electricity market is neutral on the source of generation. However, in principle, the Emissions Trading Scheme would give an advantage to renewable generation, to the extent that it produces relatively low greenhouse emissions. Renewable generation may also yield branding advantages.
Other environmental effects	The New Zealand electricity market does not directly address environmental costs or benefits. However, the consenting process takes account of environmental effects. Environmental benefits may also: <ul style="list-style-type: none"> <li>• yield branding advantages</li> <li>• help generators to forge constructive relationships with communities.</li> </ul>

Type of service	How the benefit or cost of service could be passed on to the distributed generation owner
Other benefits to the local community – eg, creating jobs	Local economic benefits may: <ul style="list-style-type: none"> <li>• yield branding advantages</li> <li>• help generators to forge constructive relationships with communities.</li> </ul>

4.2.15 The Authority has concluded that, even if ACOT payments were no longer made between distributors and distributed generation owners, distributed generation owners could still:

- (a) be paid for network and other services that they provide
- (b) face network and other costs for the service requirements that they create.

4.2.16 Key underlying assumptions are that:

- (a) Transpower would contract with distributed generators to develop and/or operate distributed generation that avoids transmission network costs, to the extent this is efficient.
- (b) Distributors would contract with distributed generators to develop and/or operate distributed generation that avoids distribution network costs, to the extent this is efficient, and make appropriate ACOD payments to the distributed generators.
- (c) Any future TPM could provide for distributed generators to pay for increasing or bringing forward transmission network costs, where they contributed to those costs.

4.2.17 The following subsections set out the Authority’s reasons for making these assumptions.

**Transpower will pay for efficiently reducing or deferring transmission network costs**

4.2.18 In summary, the regulatory arrangements applying to Transpower under the Commerce Act provide incentives for Transpower to provide a defined level of transmission service at the lowest possible cost.

4.2.19 The Authority understands that under the Commerce Act regime Transpower:

- (a) can *contract* with distributed generators to efficiently reduce or defer transmission investment costs
- (b) has an *incentive* to make such contracts



- (c) faces suitable *checks and balances* that would discourage it from contracting for distributed generation that is unlikely to efficiently reduce or defer transmission investment<sup>62</sup>
- (d) would be *ready* to contract with distributed generators by the time the proposed Code amendment came into force.

4.2.20 There have been few contracts to date between Transpower and distributed generators for transmission support services (through the demand response programme). The Authority understands this is because distributed generators have historically contracted mainly with distributors. It is also because distributed generators prefer to receive ACOT payments based on avoided transmission charges, which often exceed avoided transmission costs.

4.2.21 The Authority expects that Transpower would be able to recover any payments it makes to distributed generation from its customers, through transmission charges. The Authority has proposed a new TPM, which would change the way Transpower sets transmission charges. The proposed new TPM incorporates an area-of-benefit charge and a capacity-based residual charge. Under the proposed TPM, payments that Transpower makes to distributed generation could be recovered through either the area-of-benefit charge or the residual charge, depending on the present value of the stream of payments.<sup>63</sup>

***Transpower can contract with distributed generation***

4.2.22 As the grid planner, Transpower would have the best available information and analytical tools to determine:

- (a) where transmission investment may be needed
- (b) how the need for such investment can be efficiently reduced or deferred through the operation of distributed generation.

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<sup>62</sup> The ‘checks and balances’ applied are stronger for capex above \$20m than for capex below \$20m as there is a formal approval process of expenditure above \$20m.

<sup>63</sup> In the Authority’s TPM proposal, the method for applying the area-of-benefit charge may differ depending on whether the cost of the investment is above or below \$5m. The proposal would mean the costs of investments above \$5m would be recovered through the area-of-benefit charge as soon as a new TPM came into effect. However, the proposal may result in investments below \$5m being recovered through the residual until the method for applying the area-of-benefit charge to these investments has been developed (after which they would be recovered through the area-of-benefit charge).

This means that if the present value of the stream of ongoing payments made by Transpower to an owner of distributed generation were above \$5m, the costs of these ongoing payments would be recovered through the area-of-benefit charge. If the present value of a stream of payments were below \$5m, the costs would be recovered through the residual charge until the method for applying the area-of-benefit charge to investments below \$5m has been developed (after which they would be recovered through the area-of-benefit charge).

4.2.23 Appendix C sets out that:

- (a) Transpower's regulatory framework allows it to contract for distributed generation
- (b) Transpower has demonstrated capability in contracting for distributed generation in the course of its demand response trials.

***Transpower has an incentive to contract***

4.2.24 Appendix C sets out that:

- (a) Transpower is required to appropriately consider, and consult on, non-transmission solutions – such as contracting for distributed generation – as alternatives to major capex investment.
- (b) The Commerce Commission regime gives Transpower an incentive to contract for distributed generation to defer base capex.<sup>64</sup> Transpower has a fixed base capex allowance in each regulatory control period, irrespective of its actual expenditure. Therefore, to the extent that Transpower can reduce or defer base capex expenditure – either through distributed generation or by any other means – it has an incentive to do so.
- (c) Transpower has demonstrated willingness to contract for distributed generation in the course of its demand response trials.

4.2.25 Finally, if the form of revenue cap applying to Transpower posed an unexpected barrier to contracting for efficient distributed generation, there are provisions that allow the Commerce Commission to modify the cap in certain circumstances.

***Commerce Act regime provides checks and balances***

4.2.26 Appendix C sets out that:

- (a) In order for Transpower to recover the costs of contracting for distributed generation as an alternative to major capex investment, it must obtain Commerce Commission approval for a non-transmission solution.
- (b) The Commerce Commission regime incentivises Transpower to exercise care when contracting for distributed generation to defer or reduce base capex expenditure. Transpower is unable to seek additional revenue within the current control period to recover the costs of such distributed generation.<sup>65</sup> So it only has an incentive to procure such distributed

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<sup>64</sup> Although Transpower has an incentive, it has to share savings with consumers.

<sup>65</sup> Transpower has been granted an opex allowance of \$8 million over the five years of the current regulatory control period to fund the fixed costs of its demand response programme, but this allowance is not intended to cover the variable costs of actually procuring DR.

generation to the extent that it can efficiently defer or reduce its base capex expenditure.

- (c) In evaluating a base capex proposal, the Commerce Commission may review 'Transpower's internal processes for challenging a need for an identified programme and the possible alternative solutions'.<sup>66</sup> Therefore, Transpower has an incentive to put in place effective processes for considering distributed generation as an alternative to base capex.

***Transpower needs time to prepare***

- 4.2.27 The Authority anticipates that it would take some time for Transpower to be ready to fulfil its increased role as the funder of distributed generation to reduce network costs. In particular, Transpower would need to:
- (a) assess the effect of removing some existing ACOT payments, which could affect transmission needs in some regions
  - (b) determine what services it needed to procure from distributed generators, and its preferred approach for doing so
  - (c) ensure that, in seeking to procure services from distributed generators, it did not create perverse incentives or other undesired consequences.
- 4.2.28 Distributed generators will also need some time to prepare for the new arrangements.
- 4.2.29 Partly for these reasons, the Authority has proposed that the proposed Code amendment should be phased in by:
- (a) 1 April 2017 for distributed generation in the LNI and LSI
  - (b) 1 April 2018 for distributed generation in the UNI and USI.
- 4.2.30 There is a discussion of the reasons for this phasing in section 4.3 below.
- 4.2.31 In proposing the phasing above, the Authority has considered the competing considerations of:
- (a) providing Transpower and owners of distributed generation with enough time to prepare to contract with each other, while
  - (b) beginning to accrue the benefits of the proposed amendment sooner rather than later.
- 4.2.32 The Authority seeks submissions on any barriers that might prevent Transpower and owners of distributed generation from agreeing on ways to efficiently reduce or defer transmission investment costs. There may be different barriers applying to

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<sup>66</sup> <http://www.comcom.govt.nz/dmsdocument/13004>

existing plant and to proposed new plant. For example, parties may wish to consider whether Transpower has the right incentives to reach agreement with distributed generation owners with respect to existing plant.

**In future, the TPM could provide for distributed generators to pay for increasing or bringing forward transmission costs**

- 4.2.33 The operation of distributed generation can increase transmission costs – eg, by increasing the need for investment to allow additional power to be exported from a generating region.
- 4.2.34 However, under the current TPM:
- (a) Owners of distributed generation do not generally make payments to distributors to compensate for any increased transmission costs they may cause (except to the extent that they pay distributors for any HVDC charges and/or connection charges that distributors pass on to them). This is because the operation of distributed generation does not increase the net amount of transmission *charges* paid by the distributor.
  - (b) Owners of distributed generation do not pay transmission charges directly to Transpower.
- 4.2.35 The Authority is considering whether to propose TPM Guidelines that, amongst other things:
- (a) direct Transpower to consider introducing an LRMC charge. If introduced, distributed generators could pay to inject electricity into the grid at times of peak demand in regions that are export-constrained.<sup>67</sup>
  - (b) provide for an area-of-benefit charge. If this charge was introduced, generators (including distributed generators) would pay a portion of the costs of investments to relieve export constraints.
- 4.2.36 The Authority has been proposing to levy distributors for such charges where they arise in relation to distributed generation, although potentially owners of distributed generation could be levied directly.
- 4.2.37 Amendments to the Code would be necessary if Transpower was to levy transmission charges on distributed generators directly. At present, Transpower can levy transmission charges only on direct-connect consumers, distributors and grid-connected generators.

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<sup>67</sup> In export-constrained regions, transmission links are unable to take further electricity out of the region due to congestion.

## 4.3 The Authority proposes a phased transition

4.3.1 The Authority proposes that the Code amendment would take effect on:

- (a) 1 April 2017 for distributed generation in the LNI and LSI
- (b) 1 April 2018 for distributed generation in the UNI and USI.

4.3.2 The Authority considered bringing the Code amendment into force for all regions on 1 April 2017. This may not be workable because:

- (a) Transpower needs enough time to analyse avoided transmission benefits of existing distributed generation
- (b) Transpower needs enough time to put in place any new contracts with owners of distributed generation
- (c) Transpower and the Commerce Commission need time to agree additional payments to distributed generators for avoided costs of transmission.

4.3.3 Other options the Authority considered were:

- (a) starting with regions where there is likely to be least avoided transmission benefit
- (b) starting with larger distributed generation plants (by MW)
- (c) starting with those distributed generators who receive larger ACOT payments.

4.3.4 Transition based on transmission regions where there is likely to be least avoided transmission benefit has the following advantages:

- (a) timing of benefits. It would deliver most of the net benefit of the proposed new ACOT payment regime early in the transition. This is because it would reduce incentives to invest in or operate distributed generation in the regions where it is least likely to benefit consumers (the LNI and LSI).<sup>68</sup>
- (b) transaction costs. Transpower is likely to analyse avoided transmission benefits for distributed generation for each region. Transpower's transaction costs would be lower, as it can carry out this analysis one region at a time.
- (c) arrangements between Transpower and the Commerce Commission. If the Authority delays the new ACOT regime for those regions where there might be avoided transmission benefits, Transpower and the Commerce

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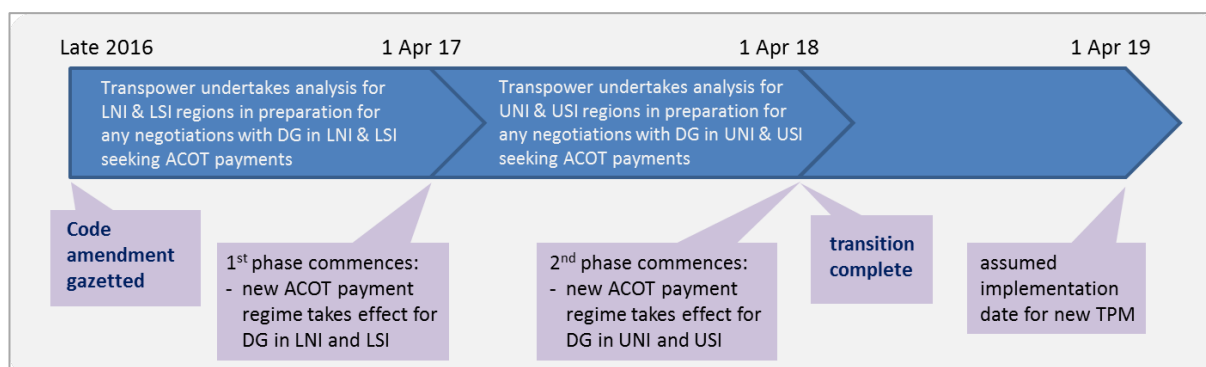
<sup>68</sup> This advantage should not be overstated. Much of the benefit of the proposed new ACOT payment regime relates to avoiding inefficient out-of-merit new distributed generation investment. The timing of this benefit relates to the date the Code amendment is gazetted, and is not affected by any of the transition options considered here.

Commission will have more time to arrange for Transpower to pay distributed generators for these benefits.

- 4.3.5 Neither a transition process based on MW capacity nor one based on size of ACOT payment would deliver the net benefits of the proposed new arrangements for the following reasons:
- (a) If the changes to the Code affected larger distributed generators (mainly hydro, geothermal and wind) first, many small- to mid-size thermal distributed generation plants might operate out of merit order.
  - (b) Larger distributed generators (which receive larger ACOT payments) are spread across all four regions. If the Authority adopted a new ACOT regime, Transpower would need to analyse payments for all regions in all phases of the transition, leading to higher transaction costs. This is because the need for transmission network support must be analysed at the level of an entire region, not at the level of an individual distributed generator.
- 4.3.6 The phasing uses the regions that Transpower has used historically for transmission charging purposes. For the LSI and LNI regions, the proposed change would take effect on 1 April 2017.
- 4.3.7 For these regions, it is unlikely that Transpower will contract with many distributed generators for transmission support. This is because distributed generation in these regions is less likely to deliver avoided transmission benefits. Transmission charging arrangements have historically provided more muted signals for controlling peak demand in the LSI and LNI, indicating that these regions are typically not import constrained.
- 4.3.8 Distributed generation in the USI and UNI is more likely to deliver avoided transmission benefits. It is more likely that Transpower will want to contract for transmission support arrangements in these regions. To allow more time for this to occur, the Authority proposes that the relevant changes in these regions will come into effect from 1 April 2018.
- 4.3.9 The timing of the transition needs to strike a balance between delivering benefits promptly and allowing enough time for participants to transition to the new regime.
- 4.3.10 The earlier transition is completed, the sooner it will deliver the full benefits of the new ACOT payment regime. Transpower needs enough time to negotiate contracts for any locations where distributed generation is required.
- 4.3.11 For practical reasons, all phases in the transition should take effect at the start of a financial year for distribution businesses (ie, 1 April).
- 4.3.12 Considering all these factors, the Authority proposes that the first phase in the transition be completed by 1 April 2017.

4.3.13 Figure 9 sets out the proposed timeframe for the suggested region-based transition.

Figure 9: Timeframe for transition



4.3.14 The Authority considers that this transition is likely to be achievable and deliver greatest net benefits early in the transition period.

4.3.15 If Transpower puts agreements in place with distributed generators faster than expected, the Authority could bring forward the date for the second phase of the transition. This would require a further Code amendment.

## 4.4 The proposal is consistent with the Authority’s statutory objective

### The proposal would promote the statutory objective by addressing the connection services issue

4.4.1 The proposed Code amendment would support the efficiency limb of the Authority’s statutory objective by better allowing distributors to adopt efficient service-based pricing structures across all distribution network users, including distributed generation owners. It would achieve this by removing the existing DGPPs, which prohibit distributors from recovering common costs from distributed generation. Removing this constraint would also reduce the likelihood of inefficient distributed generation investment or operation.

4.4.2 The Authority expects that, in the absence of schedule 6.4, distributors would determine charges for distributed generation by reference to the voluntary pricing principles. This should lead to more efficient outcomes than charges determined under the status quo (the DGPPs in schedule 6.4).

4.4.3 The voluntary distribution pricing principles stipulate that distribution prices should signal the economic costs of service provision by distributors. The principles stipulate that prices are to be equal to or greater than incremental costs, and less than or equal to standalone costs.

- 4.4.4 The proposed Code amendment would not have a major effect on the competition limb of the Authority's objective. However, by making under-pricing of distribution services to distributed generation less likely, it may better promote efficiency-enhancing competition between distributed generators and grid-connected generators. That is, subsidy-driven sources of competition, which typically harm economic efficiency, may be reduced.
- 4.4.5 The proposed Code amendment would not affect the reliability limb of the Authority's statutory objective. It would not reduce incentives for distributed generation investment or operation where there is a genuine reliability benefit.
- 4.4.6 Where distributed generation would provide a local reliability benefit (ie, avoid the need for reinforcement of the distribution network to address a constraint) this can be recognised via ACOD payments. Where distributed generation provides a wider reliability benefit, incentives in the wholesale electricity market (such as forward prices for sale of energy) would address this, and removing the DGPPs will not alter the incentives.

**The proposal would promote the statutory objective by addressing the ACOT issue**

- 4.4.7 The proposed Code amendment would support the efficiency limb of the Authority's statutory objective by reducing incentives for inefficient investment in and/or operation of distributed generation that does not reduce transmission network costs.
- 4.4.8 The proposed Code amendment would support the competition limb of the Authority's statutory objective. It will reduce the likelihood of distributed generation receiving an artificial advantage relative to grid-connected generation. That is, subsidy-driven sources of competition, which typically harm economic efficiency, would be reduced.
- 4.4.9 The proposed Code amendment would not detract from the reliability limb of the Authority's statutory objective.
- 4.4.10 Where distributed generation provides a genuine ACOT service, the Authority expects that Transpower has incentives to contract for those services. To the extent that distributed generation provides other reliability benefits (incentivised by sale of energy), the incentives are unaffected.
- 4.4.11 The proposal is not expected to have any adverse effects on reliability because there are strong incentives for distributed generation to continue operating:
- (a) the operating costs of wind and hydro (which account for most distributed generation) are low



- (b) periods of network constraint (which determine the amount of ACOT payments) generally coincide with high wholesale spot prices, meaning that distributed generators are unlikely to alter their operating behaviour.

## **4.5 The proposal would produce a net economic benefit**

4.5.1 The proposal would produce a net economic benefit, relative to the current DGPPs, across a range of scenarios concerning the future state of the TPM.

4.5.2 The remainder of section 4.5 sets out:

- (a) estimates of the economic benefits of the proposal, relative to the current DGPPs, and
- (b) the Authority's view that the estimated economic benefits of the proposal outweigh the estimated costs.

4.5.3 There is some uncertainty about the cost benefit analysis, because the Authority is separately considering whether to implement a new TPM. This means that it is not possible to know precisely what the benefits of the proposal are likely to be in the medium to long-term.

4.5.4 In light of that uncertainty, in carrying out the cost benefit analysis the Authority has assessed the proposal against two possible outcomes of the TPM review, as set out below. Under each possible outcome, the Authority has found that the proposal will result in a net benefit.

### **The economic benefits of the proposal are estimated to be between \$0.5 million and \$21.7 million present value**

4.5.5 Benefits resulting from addressing the connection services issue are set out separately from benefits resulting from addressing the ACOT issue.

#### ***Benefits of addressing the connection services issue***

4.5.6 It is not possible to assess the benefits of addressing the connection services issue in a quantitative way, because there is not enough information available. Instead, the Authority has made a qualitative assessment. The results are set out in this section.

4.5.7 There is potential for efficiency benefits to arise over time from addressing the connection services issue via the proposed amendment. This assessment is based on the following factors.

4.5.8 A large proportion of distributors' total costs are common in nature. The Authority estimates that, in aggregate, distributors incur around \$1 billion dollars per annum

in common costs.<sup>69</sup> There is therefore a sizeable pool of common costs to recover from distribution network users. Distributed generation capacity is sizeable – estimated at approximately 950 MW. For some of this distributed generation capacity, the value of services provided to the distributor may exceed the value of the distribution services used by the distributed generation (other than initial connection). This is because the distributed generation defers the need for investment.

- 4.5.9 However, it appears very unlikely that all distributed generation falls into this category of providing network support services – for example, the survey indicates only a very small proportion received ACOD payments.
- 4.5.10 The current approach of requiring distribution services to distributed generation to be charged at no more than incremental cost is likely to be suboptimal, as:
- (a) it increases the likelihood that some distributed generation does not face the full long run cost of distribution services (which includes recovery of common costs) – promoting inefficient distributed generation investment or operation
  - (b) it increases the proportion of common costs to recover from non-distributed generation users – increasing the likelihood of allocative efficiency losses.
- 4.5.11 The Authority has considered whether efficient distributed generation investment/operation might be deterred by the proposed removal of the DGPPs because distributed generation owners could have less certainty over distribution charges (relative to the current arrangements).
- 4.5.12 Distributed generators and distributors can address investment in new distributed generation through contracts between them. The contracts are permitted at present, although the current DGPPs arguably reduces the incentives on distributed generation to contract because of the relative attractiveness of the default terms. The new arrangements will remove this effect.
- 4.5.13 In respect of the operation of existing distributed generation, most distributors are subject to price-quality regulation. Such distributors cannot directly derive additional profit from higher distributed generation charges, because such increases must be offset by reductions to other users. Accordingly, any change to charges for network services provided to distributed generation would be part of a wider rebalancing. Based on current information, the Authority is not aware of any reason why any such rebalancing would promote inefficient operation of distributed generation.
- 4.5.14 Similarly, some distributors are exempt from price control because they are deemed to have sufficient incentive to act in the long-term interests of their

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<sup>69</sup> Paragraph 3.2.15 gives more information about this.

consumers. The Authority is not aware of any information to indicate that these distributors would alter charges for network services provided to distributed generation in a way that would reduce the efficient operation of distributed generation.

***Benefits of addressing the ACOT issue***

- 4.5.15 The Authority has considered the potential for the following economic benefits to arise from addressing the ACOT issue:
- (a) reducing inefficient, out-of-merit **operation** of distributed generation (and notionally embedded generation) that does not reduce or defer transmission investment costs
  - (b) reducing the scope for **retention** of distributed generation (and notionally embedded generation) that does not reduce or defer transmission investment costs, and whose retention is not justified by other benefits (such as local or market-wide reliability)
  - (c) reducing inefficient, out-of-merit **investment** in new distributed generation (and notionally embedded generation) that does not reduce or defer transmission investment costs in an efficient (ie, lowest overall cost) manner
  - (d) reducing the **allocative efficiency loss** that results from consumers paying more than is necessary, and altering their consumption decisions.
- 4.5.16 These benefits should flow directly from the proposed Code amendment for inefficient distributed generation located on distributors subject to price control. However, distributors not subject to price control would still have some incentive to contract with distributed generation to reduce transmission charges (even if this did not reduce transmission costs).
- 4.5.17 The Authority has evaluated each of the above benefits under two different TPM “future state” options:
- (a) **‘current TPM’** – in which the current TPM remains in force (with changes resulting from the Transpower operational review of the TPM applying to calculation of transmission charges from 1 April 2017). This option is likely to drive incentives in the 2015/16 and 2016/17 capacity measurement periods (which would be used to set transmission prices for the 2017/18 and 2018/19 pricing years). This option could also possibly drive incentives over a longer time span if the area-of-benefit-based TPM is not adopted as proposed.
  - (b) **‘area-of-benefit-based TPM’** – in which a new TPM incorporating an area-of-benefit charge and a capacity-based residual charge is in effect. This scenario could drive incentives from the 2017/18 capacity measurement period onwards.

- 4.5.18 The ‘area-of-benefit-based TPM’ is the new TPM that would apply if the proposal in the TPM second issues paper were adopted.
- 4.5.19 Appendix D describes the methodology the Authority used to evaluate the four sources of economic benefit, under each of the two different TPM options.
- 4.5.20 The results of the analysis are summarised in Table 4 below.

Table 4: Expected economic benefits, and gross benefits of the proposal, relative to the current DGPPs

	<b>Expected economic benefits, in \$million present value terms</b>	<b>Gross benefit to consumers, in \$million present value terms</b>
Current TPM	2.0 – 21.7	232 – 325
Current TPM for two years from April 2017, then area-of-benefit-based TPM	0.5 – 4.2	46 – 64 plus effect after 2019 (not quantified)

- 4.5.21 The estimated economic benefits of the proposal therefore fall in the range from \$0.5 million to \$21.7 million present value, depending on various uncertainties including the future development of the TPM.
- 4.5.22 The Authority has also calculated the gross benefits to consumers that would result from the proposal.<sup>70</sup> The estimated gross benefits to consumers from the proposal fall in the range from \$46 million to \$325 million present value, depending on various uncertainties including the future development of the TPM.<sup>71</sup>

**The economic costs of the proposal would be relatively immaterial**

- 4.5.23 Costs that might arise in connection services are considered separately from costs that might arise in transmission services.

<sup>70</sup> Gross benefits to consumers include wealth transfers. The Authority does not take into account wealth transfers, but it does take into account any efficiency effects that may arise from wealth transfers. Information on gross benefits is included here for information, as it may be a relevant consideration for other policy makers and stakeholders.

<sup>71</sup> This may be an overestimate of gross benefits if ACOT payments to generators have caused an oversupply of generation resulting in higher reliability and/or a suppressed spot price compared to an efficient outcome.

### ***Costs that might arise in connection services***

- 4.5.24 For connection services, the implementation cost would be modest. The Authority does not expect that major changes would be required to systems or processes. A notice period should also help to ensure that implementation costs are minimised for participants. The Authority does not expect the proposal to give rise to any other material economic costs in respect of connection services.

### ***Costs that might arise in addressing the ACOT issue***

- 4.5.25 The Authority has considered the following potential economic costs that may arise in respect of transmission services:

- (a) **dynamic inefficiency**
- (b) **transaction costs** associated with implementing the proposal
- (c) **productive inefficiency** arising from any failure to fund distributed generation to efficiently defer or reduce transmission investment costs.

### **The proposal would not reduce dynamic efficiency**

- 4.5.26 The Authority has considered whether the proposal would reduce dynamic efficiency by undermining investor confidence in the stability of regulatory arrangements. The Authority does not expect adverse effects to arise for the following reasons:

- (a) Where existing distributed generation is able to provide an efficient alternative to reduce or defer transmission costs, Transpower has incentives and the ability to contract with the relevant distributed generation owner. This should preserve investment in, and operation of, distributed generation that genuinely reduces transmission costs. Further, the Authority considers that contracting via Transpower is superior to the DGPPs mechanism because it provides greater flexibility. That is, the contracting parties can tailor pricing terms, contract durations and performance standards to each situation where distributed generation reduces transmission costs. This should promote dynamic efficiency.
- (b) Where an ACOT payment exceeds the transmission-related benefit provided by distributed generation (as can occur under the current DGPPs), this effectively represents a windfall transfer of value. It is unclear why perpetuating such a transfer would promote dynamic efficiency. Further, it is reasonable to expect prospective distributed generation investors to have evaluated their investments based on genuine transmission benefits, rather than relying on windfall transfers (such as ACOT payments). Investors should not necessarily expect windfall transfers to be sustained over the longer term. The Authority released a proposal on the TPM in October 2012 that had significant implications for the size of ACOT payments. In addition, a review

of the DGPPs appeared in the Authority's 2013/14 work programme as a pending project. On this basis, investors should have been aware, at least from 2012, that ACOT payments were coming under review and might not be sustained at existing levels over the longer term.

- (c) The level and basis of ACOT payments has not been a 'settled' area of policy. The arrangements between distributors and distributed generation owners have been affected by several regulatory changes. For example, the introduction and repeal of the Electricity Governance (Connection of Distributed Generation) Regulations 2007, the introduction of Part 6 of the Code, and the introduction and changes to price-quality regulation under the Commerce Act. Similarly, transmission pricing structures (which have affected some forms of ACOT payment) have been under almost continuous change or review for more than two decades. In this context, the proposed Code amendment would be a further step in an area that has already been subject to extensive review and change. However, the Authority expects this change to promote stability because it is clearly based upon its statutory objective.
- (d) Dynamic efficiency and investor confidence will continue to be enhanced by the Authority actively pursuing the promotion of its statutory objective.

4.5.27 In light of these factors, the Authority has not included any adverse impact on investor certainty as a potential source of economic cost.

### **There would be no change to transaction costs**

4.5.28 The Authority understands that Transpower already has a capability to assess 'transmission alternatives' (for example, via the demand response programme which also covers distributed generation). However, the Authority expects that Transpower would need to apply some additional resource in this area if it assumes the primary role as counterparty to distributed generation in contracting for transmission-substitute services.

4.5.29 The Authority expects any increase in Transpower resourcing would be offset by a reduction in resourcing at distributors. Distributors would no longer be required to assess avoided transmission charges and make ACOT payments under the DGPPs. The Authority expects the net impact to be neutral or possibly a net saving given that there are 29 distribution companies. It is also likely that Transpower could incur initial set up costs on a one-off basis in order to assess existing payments to distributed generators and determine the scope and terms of any ongoing contracts with those distributed generators.

4.5.30 The Authority expects the proposal to either reduce, or have no effect on, resource requirements on distributed generation owners.

- 4.5.31 The result would be either no change in transaction cost, or a reduction in transaction costs. For the purpose of this CBA, the Authority has conservatively assumed no change.

### **Productive inefficiency would be unaffected**

- 4.5.32 For the reasons set out in section 4.2 (from paragraph 4.2.18), the Authority expects that Transpower would contract with owners of distributed generation to defer or reduce transmission investment costs where it was efficient to do so.
- 4.5.33 Therefore, the Authority considers that there would not be a material level of productive inefficiency stemming from failure to fund distributed generation to efficiently defer or reduce transmission investment costs.

## **4.6 The Authority has identified alternatives, but prefers its proposal**

- 4.6.1 The Authority has identified one alternative approach to the connection services issue. The Authority could amend the pricing principles applying to the setting of connection charges for distributed generation (in Schedule 6.4) so that charges must be in the range from incremental cost to standalone cost of providing those services.
- 4.6.2 The Authority identified three alternative approaches capable of addressing the ACOT issue:
- (a) Alternative 1 – exclude transmission costs or charges from the definition of “incremental cost” in the DGPPs.
  - (b) Alternative 2 – ‘ban on ACOT payments by distributors’. The Authority would amend the Code to prohibit distributors from paying generators, or seeking payment from generators, in respect of avoided transmission charges or costs. As under the proposal, generators could be paid by Transpower for efficiently reducing or deferring transmission network costs.
  - (c) Alternative 3 – ‘Transpower approves ACOT payments’. Distributors would make ACOT payments to distributed generation owners if, and only if, Transpower approved the arrangement as efficiently deferring or reducing transmission investment costs. The approval process would be set out in new Code provisions.
- 4.6.3 By combining each of these alternatives with the single alternative approach to the connection services issue, the Authority has constructed three alternatives to the proposed Code amendment that address both issues.
- 4.6.4 Relative to the status quo, the Authority expects the three alternatives to provide broadly similar benefits and costs to the preferred option. The Authority has

assessed all four options (ie, the proposal and the three alternatives) against the 'tiebreaker' Code amendment principles 4-8, and concluded that the proposal is most consistent with the 'tiebreaker' principles (see section 4.7).

### **The Authority has identified an alternative approach to addressing the connection services issue**

- 4.6.5 An alternative way to address the connection services issue is to amend the pricing principle applying to the setting of connection charges for distributed generation. The pricing principle is currently set out in clause 2(a) of Schedule 6.4.
- 4.6.6 The current pricing principle states that '... **connection** charges in respect of **distributed generation** must not exceed the **incremental costs** of providing **connection** services to the **distributed generation**.'
- 4.6.7 The alternative approach would amend this principle as follows:
- (a) the distributor must set connection charges in respect of distributed generation and in doing so must—
    - (i) separately identify—
      - (A) the cost of connecting the distributed generation; and
      - (B) ongoing charges for distribution services and connection services to the distributed generation; and
    - (ii) set the charges so as to recover—
      - (A) no less than the incremental cost of providing those services; and
      - (B) no more than the standalone cost of providing those services.
- 4.6.8 The costs identified as 'incremental costs' would remain the same, except that transmission charges avoided by the distributor would not be deducted. However, under the alternative approach, incremental costs would reflect a lower bound for connection charges (ie the lowest dollar amount that connection charges could be set at), rather than an upper bound, as at present.
- 4.6.9 The upper bound under the alternative approach would be standalone cost. Standalone cost is the reasonable cost that a party would incur in providing services equivalent to distribution services by alternative means, in isolation from all other services provided by that distributor.
- 4.6.10 The alternative approach would therefore affect the calculation of charges payable by a distributor to a distributed generation, or vice versa, if:
- (a) the regulated terms set out in Schedule 6.2 applied; or



- (b) a dispute under Part 6 had occurred, and the Authority and the Rulings Panel considered it was necessary or desirable to apply the DGPPs to determine the connection charges payable, in order to resolve the dispute.<sup>72</sup>

### **The Authority has identified three alternative approaches to improve treatment of ACOT**

- 4.6.11 The Authority has identified three alternative approaches to the ACOT issue—as described in the following three subsections.
- 4.6.12 In addition to these three alternatives, the Authority has also considered three other options, but it did not evaluate these options in detail because they would not address the objective. (Appendix E provides a summary of these other options).

#### ***Alternative 1 – Define incremental cost to exclude transmission***

- 4.6.13 Under this alternative, reference to transmission costs and charges would be excluded from the definition of “incremental cost” in the DGPPs, to address the ACOT issue. As a result, distributors providing connection services to distributed generation on the default/regulated terms would no longer be required to take account of the effect on transmission charges when setting connection charges. In this respect (effects on ACOT payments), this alternative is similar to the proposed option.
- 4.6.14 As with the proposed option, where distributed generation provides a genuine transmission-substitute service, this can be recognised in the agreements between Transpower and distributed generation owners, which the existing regulatory framework provides for (see section 4.2). This alternative would also give Transpower primary responsibility for obtaining/paying for transmission-substitute services provided by distributed generation.

#### ***Alternative 2 – Ban on ACOT payments by distributors***

- 4.6.15 Under this alternative, the Authority would amend the Code to prohibit distributors from paying generators, or seeking payment from generators, in respect of avoided transmission charges or costs.
- 4.6.16 The prohibition:
- (a) would apply to all distributor-generator contracts (not only those using the DGPPs regulated terms)
  - (b) would apply to payments between distributors and grid-connected generators, as well as those between distributors and distributed generation owners

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<sup>72</sup> This is set out in clause 4 of Schedule 6.3 of the Code.

- (c) would forbid payments only for avoided *transmission* charges or costs. Payments could still be made in respect of avoided connection or distribution costs (or any other benefits that a distributor was prepared to recognise)
- (d) would not apply to situations where a distributor was acting as an aggregator, and procuring transmission alternative services on behalf of Transpower.

4.6.17 Under this alternative, as under the proposal, generators could be paid by Transpower for efficiently reducing or deferring investment in the transmission network.

***Alternative 3 – Transpower approves ACOT payments***

4.6.18 Under this alternative:

- (a) Distributors would make ACOT payments to distributed generation owners if, and only if, Transpower approved the arrangement as efficiently deferring or reducing transmission investment costs
- (b) Distributed generation owners would not make ACOT payments to distributors.

4.6.19 The Code would provide for a process along the following lines:

- (a) An owner of existing distributed generation, or the owner of proposed distributed generation, would ask the relevant distributor to provide ACOT payments.
- (b) The distributor would forward the request to Transpower.
- (c) Transpower would assess whether the operation of the distributed generation could efficiently defer or reduce transmission investment costs. The assessment would include carrying out a net benefit test.
- (d) Transpower would decide either:
  - (i) that the distributor should pay ACOT to the distributed generation owner – in which case Transpower would determine:
    - the basis of the payments (eg mean generation at local peak time)
    - the rate of the payments (eg in \$/kW terms)
    - how long payments should continue (eg, five years)
    - any conditions that the distributed generation should satisfy in order to receive ACOT (eg undertaking to provide a specified level of reliability during peak times), or
  - (ii) that the distributor should not pay ACOT to the distributed generation.
- (e) Transpower's decision would be binding.

- 4.6.20 Under this option, a distributor subject to price control would be able to recover the cost of approved ACOT payments from its load customers, under the current Input Methodologies.
- 4.6.21 This option was developed to find a solution that would work even if Transpower were unable to access funds for procurement of distributed generation. However, at this point it does not appear that Transpower’s access to funding would be a constraint (see section 4.2, from para 4.2.18).

**Comparing the alternatives – connection services issue**

- 4.6.22 There is insufficient information to enable a quantitative assessment of costs and benefits to determine whether the Authority’s proposal or the alternative approach is better in terms of resolving the connection services issue. DGPPs
- 4.6.23 The Authority’s qualitative assessment of the relative advantages of the proposal and the alternative approach to the connection services issue is set out in Table 5. The alternative approach is to amend the DGPPs in Schedule 6.4 so that charges must be in the range from incremental cost to standalone cost of providing those services.<sup>73</sup>
- 4.6.24 The Authority’s proposal scores better than the alternative approach against these criteria. This is because it meets the “like treatment of all distribution network customers” criterion, and the alternative approach does not. Both options meet all other criteria.

Table 5: Qualitative assessment of the proposal against the alternative

<b>Criterion</b>	<b>The proposal – ‘Remove the DGPPs from Part 6’</b>	<b>Alternative approach – ‘Amend the DGPPs in Schedule 6.4’</b>
Address constraint that hinders adoption of efficient service-based pricing for all distribution network users	<p style="text-align: center;">✓</p> Deleting the DGPPs would address current constraint	<p style="text-align: center;">✓</p> Amended DGPPs would address current constraint

<sup>73</sup> All three alternatives to the Authority’s proposal incorporate the same approach to the connection services issue.

Criterion	The proposal – ‘Remove the DGPPs from Part 6’	Alternative approach – ‘Amend the DGPPs in Schedule 6.4’
Address constraint that may promote inefficient distributed generation investment and/or operation	<p style="text-align: center;">✓</p> Deleting the DGPPs would address current constraint	<p style="text-align: center;">✓</p> Amended DGPPs would address current constraint
Risk of unintended adverse consequences	<p style="text-align: center;">✓</p> Based on the available information, there appears to be limited likelihood of unintended adverse consequences. (Distributors are expected to set charges at similar levels for both alternatives)	<p style="text-align: center;">✓</p> Based on the available information, there appears to be limited likelihood of unintended adverse consequences. (Distributors are expected to set charges at similar levels for both alternatives)
Cost to implement	<p style="text-align: center;">✓</p> The cost to implement (eg, negotiation of contracts) is not expected to be excessive – especially given a lead time for participants	<p style="text-align: center;">✓</p> The cost to implement (eg, negotiation of contracts) is not expected to be excessive – especially given a lead time for participants
Like treatment of all distribution network customers	<p style="text-align: center;">✓</p> Removing DGPPs would mean pricing for distributed generation and other connections on the same basis	<p style="text-align: center;">✗</p> Amending DGPPs means there would still be special rules for setting prices for distributed generation as opposed to other connections

4.6.25 It might be argued that the alternative approach would result in more efficient pricing compared to the proposal. This is because the alternative approach requires distributors to set prices in the range from incremental cost to standalone cost, whereas the proposal allows distributors to set prices outside those bounds.

4.6.26 However, the Authority considers that this apparent difference is unlikely to have material consequences in practice. A requirement to price below standalone cost

for distributed generation imposes little real constraint on distributors, as this bound is likely to be very high. It also seems unlikely that setting charges below incremental cost is prevalent. Distributors that are subject to price control would not derive any financial benefit from this.<sup>74</sup> Those not subject to price control would incur (or increase the size of) financial losses on the provision of such services.

- 4.6.27 Further, under the proposal, the distribution pricing principles would apply. Although the distribution pricing principles are voluntary, the Authority expects that distributors following good industry practice would align their pricing methodologies with the principles.
- 4.6.28 There are established checks on whether distributors are following the pricing principles. The Commerce Commission information disclosure regime requires all distributors to disclose the extent to which their pricing methodologies are consistent with the distribution pricing principles. The Authority initiates periodic reviews of the extent to which distributors' pricing methodologies align with the distribution pricing principles.
- 4.6.29 A possible exception could be a situation where distributors provide services to distributed generation owned by a related party (such as a wholly owned subsidiary). Arguably, in such cases a distributor might be able to capture a benefit via the related party. However, the Commerce Act regime applying to distributors requires information disclosure regarding related party transactions, limiting this concern.

### **Comparing the options – ACOT issue**

- 4.6.30 The Authority has developed a quantitative cost-benefit analysis of the preferred option. However, the Authority expects the three alternatives and the preferred option to provide broadly similar ACOT-related benefits and costs relative to the status quo. Where there are differences between the proposal and the three alternatives, it is not feasible to quantify them based on the currently available information.
- 4.6.31 Instead, the Authority has:
- (a) carried out a qualitative assessment of the relative advantages of the four options (ie, the proposal and the three alternatives), set out in this section, which did not produce a single best option
  - (b) assessed the four options against the 'tiebreaker' Code amendment principles 4-8, and concluded that the proposal is most consistent with the 'tiebreaker' principles (section 4.7). For this reason, the Authority considers that the proposal is preferable to the three alternatives.

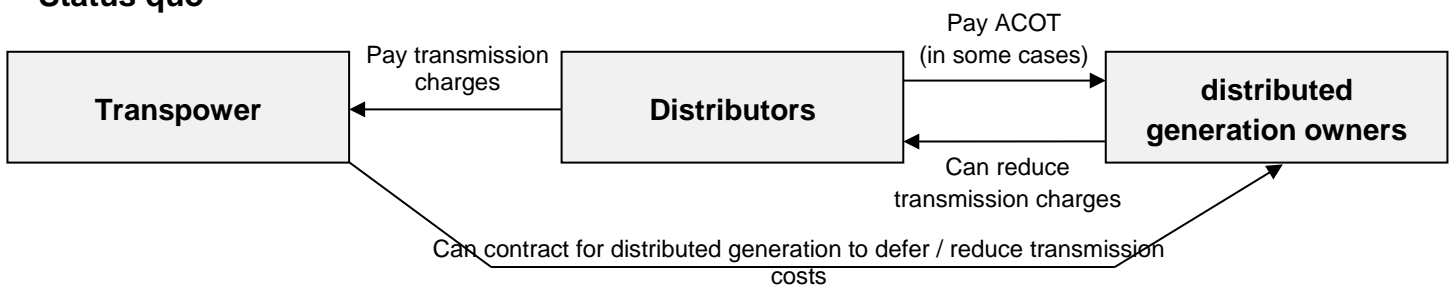
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<sup>74</sup> Assuming that the business is pricing up to the allowable weighted average price cap.

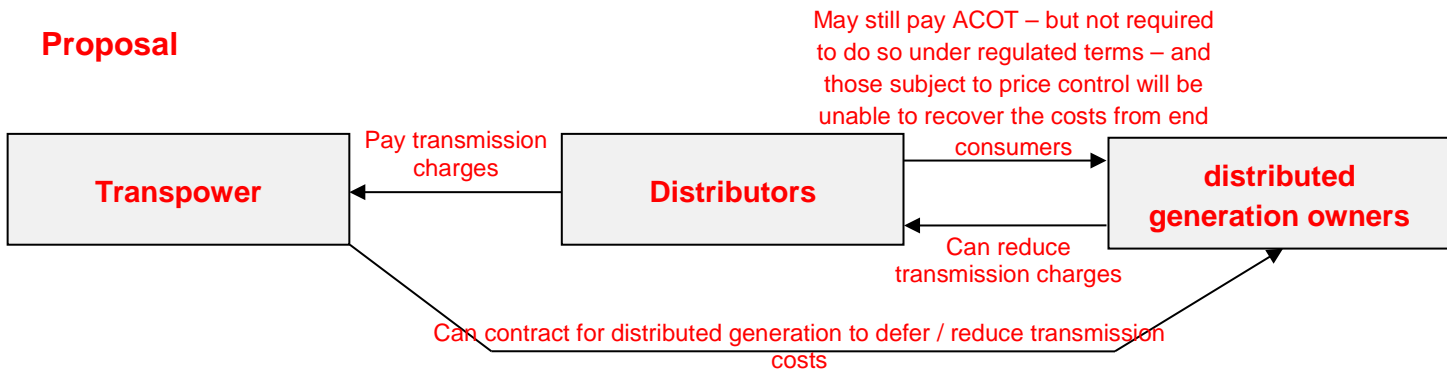
4.6.32 The four options, and the status quo, are summarised in Figure 10. For each option, the diagram shows the roles and responsibilities of Transpower, distributors and distributed generation owners in using distributed generation to achieve deferral or reduction of transmission investment. The Authority acknowledges that the diagrammatic presentation is a simplified representation of the relationships between parties. The Authority’s qualitative assessment of the relative advantages of the four alternatives follows in Table 6.

Figure 10: ACOT-related roles and responsibilities under the status quo, the proposal and the three alternatives considered

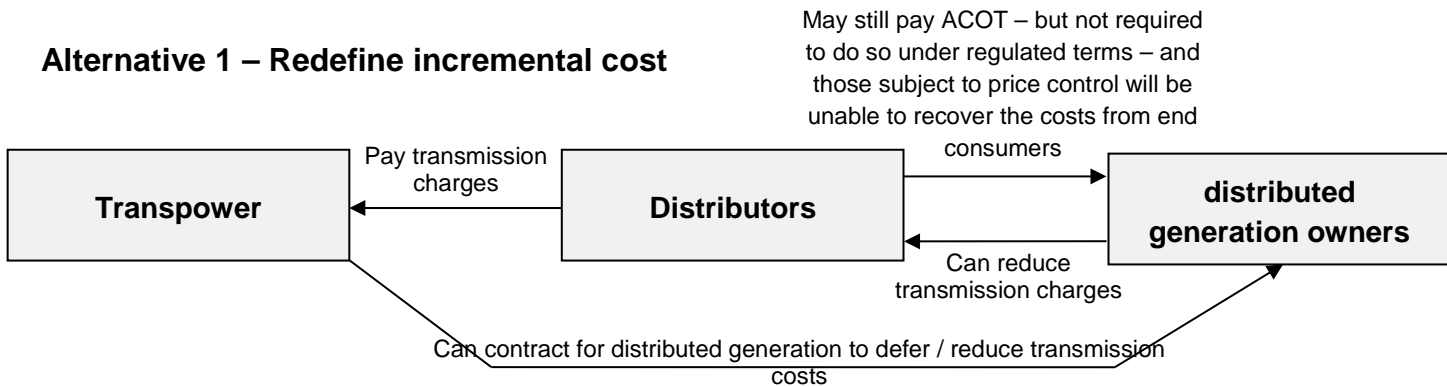
**Status quo**



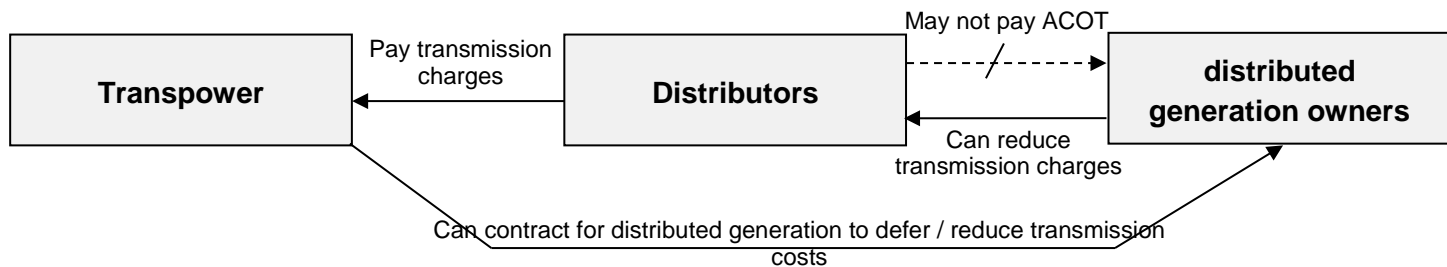
**Proposal**



**Alternative 1 – Redefine incremental cost**



**Alternative 2 – Ban on ACOT**



**Alternative 3 – Transpower approves ACOT**

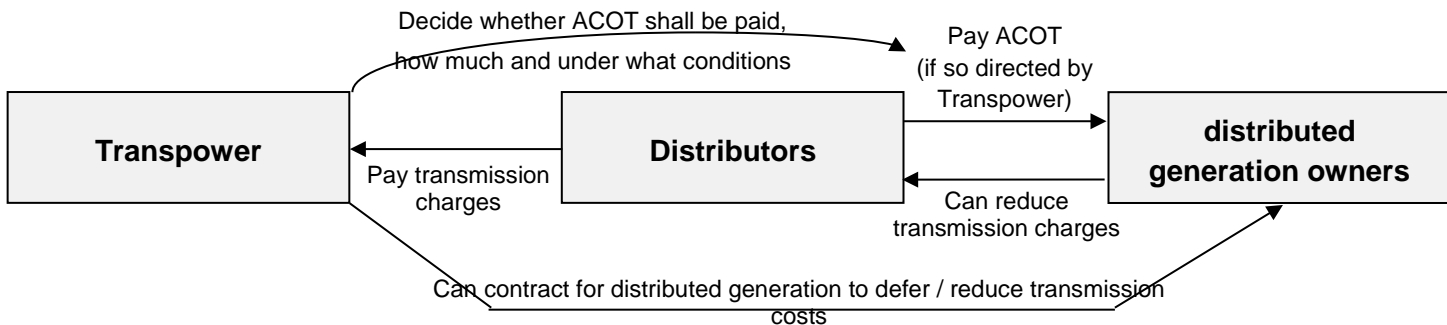


Table 6: ACOT-related qualitative assessment of the proposal against the alternatives

Criterion	The proposal	Alternative 1 – Redefine incremental cost	Alternative 2 – Ban on ACOT	Alternative 3 – Transpower approves ACOT
Option would avoid creating an inefficient incentive for investment in and/or operation of distributed generation	<p style="text-align: center;">✓</p> <p>The scope for inefficient ACOT payments would be considerably reduced.</p> <p>However, the proposal has one tick because its coverage would not be complete. Distributors would no longer be driven toward the default option of being required to make ACOT payments based on avoided transmission charges. Similarly, it would deter distributors subject to price-quality control from making such payments because they would no longer be able to recover the costs. But distributors could still make some non-cost-reflective ACOT payments because the DGPPs are not mandatory.</p>		<p style="text-align: center;">✓✓</p> <p>This option earns two ticks because it would have wider coverage than the proposal.</p> <p>However, the coverage might still not be complete, for the reasons set out in the bottom row of this table.</p>	<p style="text-align: center;">✓</p> <p>As under the proposal, the scope for inefficient ACOT payments would be considerably reduced but not potentially eliminated.</p>
Option would provide an efficient incentive for investment in and/or operation of distributed generation to defer or reduce transmission investment	<p style="text-align: center;">✓✓</p> <p>Transpower could pay distributed generation owners for efficiently reducing or deferring transmission network costs.</p>			<p style="text-align: center;">✓✓</p> <p>Transpower would determine when and how distributed generation would receive ACOT payments from distributors for efficiently reducing or deferring transmission network costs.</p>



Criterion	The proposal	Alternative 1 – Redefine incremental cost	Alternative 2 – Ban on ACOT	Alternative 3 – Transpower approves ACOT
Likelihood of undesirable consequences	<p style="text-align: center;">✓</p> <p>There is the possibility that some distributors would continue to make inefficient ACOT payments. However, such payments would no longer be recoverable from customers, for distributors subject to price-quality control.</p> <p>Otherwise, based on the available information, the Authority has reasonable confidence that the proposal would avoid undesired consequences.</p>		<p style="text-align: center;">X</p> <p>This option receives a cross for several reasons.</p> <p>Firstly, the blanket nature of the ban might give rise to unintended consequences.</p> <p>Secondly, some parties might circumvent the ban on ACOT payments, by transferring value from a distributor to a distributed generation owner in some form other than an ACOT payment.</p> <p>Thirdly, this option might incentivise distributors to inefficiently acquire distributed generation in their network area, to capture the benefits of avoided transmission charges without needing to make ACOT payments.</p>	<p style="text-align: center;">X</p> <p>This option receives a cross because the process for requesting and approving (or declining to approve) ACOT would be new and untested. It is possible that the process might not work as intended, and might produce some inefficient outcomes.</p> <p>Also, the costs of payments to defer or avoid a particular transmission investment would be recovered through customers in the local distributor area, rather than through the TPM. In some cases, this could result in a mismatch between costs and benefits.</p>

4.6.33 The Authority has assessed the proposal and the three alternatives against the ‘tiebreaker’ Code amendment principles 4 to 8. Based on this assessment (which is set out in section 4.7), it has concluded that the proposal to remove the DGPPs, rather than amend them, is most consistent with the ‘tiebreaker’ principles (particularly the preference not to be prescriptive). For this reason, the Authority considers that the proposal is preferable to the alternatives.

## 4.7 The proposed amendment is consistent with Code amendment principles

4.7.1 The assessment of costs and benefits is inconclusive as to which of the options set out in section 4.6 is preferable. In these circumstances, the Authority applies principles 4-8 of the Code amendment principles as a tiebreaker.

4.7.2 The Authority concludes that the proposal is preferable to the alternatives set out in section 4.6, because it is equally consistent with Code amendment principles 4 and 6, and more consistent with principles 5, 7 and 8.

4.7.3 Table 7 describes the Authority’s analysis of the Code amendment principles for the proposed Code amendment.

Table 7: Regard for Code amendment principles

Principle	Comment
1. Lawful	The proposed Code amendment is lawful, and is consistent with the statutory objective and with the empowering provisions of the Act.
2. Provides clearly identified efficiency gains or addresses market or regulatory failure	The proposed Code amendment will provide clearly identified efficiency gains, as set out in Sections 4.2, 4.4 and 4.5.
3. Net benefits are quantified	The proposed Code amendment will provide a net economic benefit relative to the status quo, as set out in section 4.5.
<i>Because the assessment of costs and benefits is inconclusive as to which of the alternatives set out in section 4.6 is preferable, the Authority has applied principles 4-8.</i>	
4. Preference for small-scale ‘trial and error’ options	Neither the proposal nor the alternatives can be considered small-scale ‘trial and error’ options.

Principle	Comment
5. Preference for greater competition	The proposal, by reducing the likelihood of distributed generation receiving an artificial advantage relative to grid-connected generation, should better promote competition between distributed generation and grid-connected generation.
6. Preference for market solutions	All options considered provide for connection charges to be calculated administratively, rather than through a market.
7. Preference for flexibility to allow innovation	The proposal provides distributors with greater flexibility to adopt more efficient pricing structures. This should support innovation over time, for example in the efficient deployment of new technologies.
8. Preference for non-prescriptive options	<p>The proposal is less prescriptive than the status quo, and also less prescriptive than the other options considered – in that:</p> <ul style="list-style-type: none"> <li>• the status quo option retains the DGPPs, so continues to place constraints on distributor pricing to distributed generation</li> <li>• the ‘Ban on ACOT’ option (Alternative option 2) would entirely forbid all distributors from paying distributed generation for avoided transmission costs or charges, and</li> <li>• the ‘Transpower approves ACOT’ option (Alternative option 3) would require distributors to pay distributed generation for avoided transmission costs if and only if Transpower approved it, while</li> <li>• the proposal neither forbids distributors from making, nor requires them to make, payments in respect of avoided transmission costs or charges.</li> <li>• Alternative 1 is no more prescriptive than the proposal in terms of ACOT payments; however, it is more prescriptive than the proposal in terms of connection services charges.</li> </ul>

## **4.8 The proposed Code amendment complies with section 32(1) of the Act**

- 4.8.1 Section 32(1) of the Electricity Industry Act 2010 (Act) provides that Code provisions must be consistent with the Authority's objective and be necessary or desirable to promote any or all of the following:
- (a) competition in the electricity industry
  - (b) the reliable supply of electricity to consumers
  - (c) the efficient operation of the electricity industry
  - (d) the performance by the Authority of its functions
  - (e) any other matters specifically referred to in the Act as a matter for inclusion in the Code.
- 4.8.2 Table 8 sets out an assessment of the proposed Code amendment against the requirements of section 32(1) of the Act.

Table 8: How proposed Code amendment complies with section 32(1) of the Act

Requirement	Comment
<p>The proposed Code amendment is consistent with the Authority’s objective under section 15 of the Act. The Authority’s objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.</p>	<p>As set out in section 4.4, the proposed Code amendment would promote efficiency by:</p> <ul style="list-style-type: none"> <li>• reducing the likelihood of inefficient distributed generation investment and operation, and</li> <li>• reducing the likelihood of allocative efficiency losses that result from consumers paying more than is necessary, and altering their consumption decisions.</li> </ul> <p>The proposed Code amendment would support the competition limb of the Authority’s statutory objective because it will reduce the likelihood that distributed generation would be artificially advantaged, relative to grid-connected generation.</p> <p>The proposed Code amendment would not detract from the reliability limb of the Authority’s statutory objective because it would not reduce incentives for distributed generation investment and operation where there is a genuine reliability benefit. Where distributed generation provides a genuine ACOT service, the Authority expects that Transpower has the ability and incentives to contract for such services. More generally, to the extent that distributed generation provides other reliability benefits (incentivised via sale of energy), these incentives will be retained.</p>
<p>The proposed Code amendment is necessary or desirable to promote any or all of the following:</p>	
<p>(a) competition in the electricity industry</p>	<p>The proposed Code amendment will better promote competition between distributed generation and grid-connected generation.</p>
<p>(b) the reliable supply of electricity to consumers</p>	<p>The proposed Code amendment will not have a material effect on reliability.</p>
<p>(c) the efficient operation of the electricity industry</p>	<p>The proposed Code amendment will promote efficiency as set out above.</p>

<p>(d) the performance by the Authority of its functions</p>	<p>The proposed Code amendment will not have a material effect on the performance by the Authority of its functions.</p>
<p>(e) any other matter specifically referred to in this Act as a matter for inclusion in the Code.</p>	<p>The proposed Code amendment will not materially affect any other matter specifically referred to in the Act for inclusion in the Code.</p>

- Q1.** Do you consider that the proposed Code amendment described in section 4.1 is preferable to the status quo and the alternatives described in section 4.6? If not, please explain your preferred option(s) in terms consistent with the Authority’s statutory objective.
- Q2.** Do you consider that the proposed Code amendment described in section 4.1 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?
- Q3.** Do you have any comments on the drafting of the proposed Code amendment described in section 4.1? (The drafting is included in Appendix B.)
- Q4.** Do you consider that the proposed Code amendment should come into force at a single date, or should it be phased in?
- Q5.** Is the proposed phasing for the Code amendment appropriate? (The phasing is discussed in section 4.3.) If not, what alternative phasing or dates would you propose and why?
- Q6.** If the proposal were to proceed, do you consider that there would be barriers that might prevent agreements being reached between Transpower and distributed generation owners to efficiently reduce or defer transmission network costs? If so, what are these barriers? Please consider both existing and proposed new distributed generation.
- Q7.** If the proposal were to proceed, do you consider that there would be barriers that might prevent agreements being reached between distributors and distributed generation owners to efficiently reduce or defer distribution network costs? If so, what are these barriers? Please consider both existing and proposed new distributed generation.
- Q8.** If the proposal were to proceed, do you consider that those distributors that were no longer able to recover the cost of making ACOT payments would cease making such payments?





## Appendix A Format for submissions

Question No.	Question	Response
Q1.	Do you consider that the proposed Code amendment described in section 4.1 is preferable to the status quo and the alternatives described in section 4.6? If not, please explain your preferred option(s) in terms consistent with the Authority's statutory objective.	
Q2.	Do you consider that the proposed Code amendment described in section 4.1 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?	
Q3.	Do you have any comments on the drafting of the proposed Code amendment described in section 4.1? (The drafting is included in Appendix B.)	
Q4.	Do you consider that the proposed Code amendment should come into force at a single date, or should it be phased in?	
Q5.	Is the proposed phasing for the Code amendment appropriate? (The phasing is discussed in section 4.3.) If not, what alternative phasing or dates would you propose and why?	

<p>Q6.</p>	<p>If the proposal were to proceed, do you consider that there would be barriers that might prevent agreements being reached between Transpower and distributed generation owners to efficiently reduce or defer transmission network costs? If so, what are these barriers? Please consider both existing and proposed new distributed generation.</p>	
<p>Q7.</p>	<p>If the proposal were to proceed, do you consider that there would be barriers that might prevent agreements being reached between distributors and distributed generation owners to efficiently reduce or defer distribution network costs? If so, what are these barriers? Please consider both existing and proposed new distributed generation.</p>	
<p>Q8.</p>	<p>If the proposal were to proceed, do you consider that those distributors that were no longer able to recover the cost of making ACOT payments would cease making such payments?</p>	

## Appendix B Code amendment

B.1 The Authority's proposed Code amendment is set out here. This Code amendment addresses both the connection services issue and the ACOT issue (see section 4).

### Changes to Part 1

~~incremental costs~~, for the purpose of Part 6, means the reasonable costs that an efficient ~~distributor~~ would incur in providing ~~electricity~~ distribution services with ~~connection~~ services to ~~distributed generation~~, less the costs that the efficient ~~distributor~~ would incur if it did not provide those ~~connection~~ services

### Changes to Part 6

#### 6.1 Contents of this Part

This Part specifies—

...

(e) ~~in Schedule 6.4, the pricing principles to be applied for the purposes of this Part; and~~

...

#### ~~6.9 Pricing principles~~

~~Schedule 6.4 applies in accordance with—~~

~~(a) clause 19 of Schedule 6.2; and~~

~~(b) clause 4 of Schedule 6.3.~~

#### 6.9 Pricing

Charges that are payable by a **distributed generator** or **distributor** in relation to the **connection** and **continued connection** of **distributed generation** on **regulated terms** must be as agreed between the **distributed generator** and the **distributor**.

...

### Schedule 6.2

...

#### *Pricing*

#### ~~19 Pricing principles~~

~~Charges that are payable by the **distributed generator** or the **distributor** must be determined in accordance with the pricing principles set out in Schedule 6.4.~~

...

### Schedule 6.3

...

#### 4 Application of pricing principles to disputes

(1) ~~The **Authority** and the **Rulings Panel** must apply the pricing principles set out in Schedule 6.4 to determine any **connection** charges payable.~~

(2) ~~Subclause (1) applies if—~~

~~(a) there is a dispute under Part 6 of this Code; and~~

~~(b) in the opinion of the **Authority** or the **Rulings Panel** it is necessary or desirable to apply subclause (1) in order to resolve the dispute.~~

...

#### Schedule 6.4

- 1— This Schedule sets out the pricing principles to be applied for the purposes of Part 6 of this Code in accordance with clause 6.9 (which relates to clause 19 of Schedule 6.2 and clause 4 of Schedule 6.3).
- 2— The pricing principles are as follows:

*Charges to be based on recovery of reasonable costs incurred by distributor to connect the distributed generator and to comply with connection and operation standards within the distribution network, and must include consideration of any identifiable avoided or avoidable costs*

- (a) subject to paragraph (i), ~~connection charges in respect of distributed generation must not exceed the incremental costs of providing connection services to the distributed generation. To avoid doubt, incremental cost is net of transmission and distribution costs that an efficient distributor would be able to avoid as a result of the connection of the distributed generation:~~
- (b) ~~costs that cannot be calculated (eg, avoidable costs) must be estimated with reference to reasonable estimates of how the distributor's capital investment decisions and operating costs would differ, in the future, with and without the generation:~~
- (c) ~~estimated costs may be adjusted ex post. Ex post adjustment involves calculating, at the end of a period, what the actual costs incurred by the distributor as a result of the distributed generation being connected to the distribution network were, and deducting the costs that would have been incurred had the generation not been connected. In this case, if the costs differ from the costs charged to the distributed generator, the distributor must advise the distributed generator and recover or refund those costs after they are incurred (unless the distributor and the distributed generator agree otherwise):~~

#### *Capital and operating expenses*

- (d) ~~if costs include distinct capital expenditure, such as costs for a significant asset replacement or upgrade, the connection charge attributable to the distributed generator's actions or proposals is payable by the distributed generator before the distributor has committed to incurring those costs. When making reasonable endeavours to facilitate connection, the distributor is not obliged to incur those costs until that payment has been received:~~
- (e) ~~if incremental costs are negative, the distributed generator is deemed to be providing network support services to the distributor, and may invoice the distributor for this service and, in that case, the distributed generator must comply with all relevant obligations (for example, obligations under Part 6 of this Code and in respect of tax):~~
- (f) ~~if costs relate to ongoing or periodic operating expenses, such as costs for routine maintenance, the connection charge attributable to the distributed generator's actions or proposals may take the form of a periodic charge:~~
- (g) ~~[Revoked]~~
- (h) ~~after the connection of the distributed generation, the distributor may review the connection charges payable by a distributed generator not more than once in any 12 month period.~~

Following a review, the **distributor** must advise the **distributed generator** in writing of any change in the **connection** charges payable, and the reasons for any change, not less than 3 months before the date the change is to take effect:

*Share of generation driven costs*

- (i) — if multiple **distributed generators** are sharing an investment, the portion of costs payable by any **distributed generator** —
- (i) — must be calculated so that the charges paid or payable by each **distributed generator** take into account the relative expected peak of each **distributed generator's** injected generation; and
- (ii) — may also have regard to the percentage of **assets** that will be used by each **distributed generator**, the percentage of **distribution network capacity** used by each **distributed generator**, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the **distribution network**;
- (j) — in order to facilitate the calculation of equitable **connection** charges under paragraph (i), the **distributor** must make and retain adequate records of investments for a period of 60 months, provide the rationale for the investment in terms of facilitating **distributed generation**, and indicate the extent to which the associated costs have been or are to be recovered through generation **connection** charges:

*Repayment of previously funded investment*

- (k) — if a **distributed generator** has paid **connection** charges that include (in part) the cost of an investment that is subsequently shared by other **distributed generators**, the **distributor** must refund to the **distributed generator** all **connection** charges paid to the **distributor** under paragraph (i) by other **distributed generators** in respect of that investment:
- (l) — if there are multiple prior **distributed generators**, a refund to each **distributed generator** referred to in paragraph (k) must be provided in accordance with the expected peak of that **distributed generator's** injected generation over a period of time agreed between the **distributed generator** and the **distributor**. The refund —
  - (i) — must take into account the relative expected peak of each **distributed generator's** injected generation; and
  - (ii) — may also have regard to the percentage of **assets** that will be used by each **distributed generator**, the percentage of **distribution network capacity** used by each **distributed generator**, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the **distribution network**;
- (m) — no refund of previous payments from the **distributed generator** referred to in paragraph (k) is required after a period of 36 months from the initial **connection** of that **distributed generator**:

*Non firm connection service*

- (n) — to avoid doubt, nothing in Part 6 of this Code creates any **distribution network capacity** or property rights in any part of the **distribution network** unless these are specifically contracted for. **Distributors** must **maintain connection and lines** services to **distributed generators** in accordance with their **connection and operation standards**.

~~3~~ *[Revoked]*

## Commencement/transitional provisions

*(To be included in the amendment instrument for the above changes):*

### **2 Commencement**

This amendment comes into force on 1 April 2017.

*(To be added to Part 17):*

#### **17.23A Delayed application of Electricity Industry Participation Code Amendment (Distributed Generation Pricing) 2015 in Upper North Island and Upper South Island**

- (1) Despite clause 2 of the Electricity Industry Participation Code Amendment (Distributed Generation Pricing) 2015, until the close of 31 March 2018, Part 6 of this Code applies to the Upper North Island and Upper South Island as if the Electricity Industry Participation Code Amendment (Distributed Generation Pricing) 2015 had not been made.
- (2) In this clause,—
  - (a) Upper North Island is that part of the North Island situated on, or north and west of, a line—
    - (i) commencing at 38°02'S and 174°42'E; then
    - (ii) proceeding in a generally north-easterly direction directly to 37°36'S and 175°27'E; then
    - (iii) proceeding north along the 175°27'E line of longitude; and
  - (b) Upper South Island is that part of the South Island situated on, or north of, a line passing through 43°30'S and 169°30'E, and 44°40'S and 171°12'E.

## Appendix C Regulatory regime applying to Transpower

- C.1 The regulatory framework applying to Transpower provides incentives for Transpower to:
- (a) make efficient trade-offs between capital and operating expenditure, and
  - (b) consider and procure 'transmission substitutes' where it is efficient to do so.<sup>75</sup> These substitutes can include distributed generation (distributed generation) and/or demand response (DR).
- C.2 This section describes:
- (a) the incentives on Transpower in relation to management of its base expenditure allowance
  - (b) The incentives on Transpower in relation to major capital expenditure which are enhancement and development proposals with costs of \$20 million or above
  - (c) Transpower's 'DR programme'.

### Transpower has a base expenditure allowance

- C.3 Transpower has a predefined revenue allowance for both base capex and opex in each regulatory control period.<sup>76</sup> It also has defined network performance (service) standards that it is measured against. In addition to its predefined revenue allowance Transpower is also able to recover certain costs outside its control, known as pass-through costs and recoverable costs.<sup>77</sup>
- C.4 With respect to the revenue allowance, Transpower is subject to symmetric incentives that:<sup>78</sup>
- (a) allow it to keep 33 cents of each dollar of savings in base capex and opex in the control period
  - (b) require it to contribute 33 cents of each dollar of additional spending in base capex and opex in the control period.

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<sup>75</sup> 'Transmission substitutes' refers to the generic range of options that can be used instead of conventional transmission investment, including the 'transmission alternatives' regime, and the 'demand response' programme.

<sup>76</sup> <http://www.comcom.govt.nz/dmsdocument/12769>. The allowances are fixed, subject to ex post adjustments for CPI and foreign exchange.

<sup>77</sup> Transpower Input methodologies Determination [2012] NZCC 17, 3.1.2 and 3.1.3.

<sup>78</sup> See Schedule B Division 1 of Capex IM, and <http://www.comcom.govt.nz/dmsdocument/12725>, respectively.

- C.5 Transpower is permitted to utilise transmission substitutes, including distributed generation, where it wishes, provided it can still meet the defined service standard.<sup>79</sup>
- C.6 Therefore, Transpower is incentivised to find the lowest cost means of meeting its defined service standards. This could include, for example, procuring transmission substitutes. These could be included if by doing so Transpower can make a saving (in present value terms) relative to the use of conventional transmission services (ie, investment in conductors, substations etc).
- C.7 Further, in evaluating a base capex programme, the Commerce Commission may review, inter alia, Transpower's internal processes for challenging a need for an identified programme and the possible alternative solutions.
- C.8 The Authority understands that, other than via its DR programme (see below), Transpower has not to date contracted directly with generation to defer base capex investment. Transpower is exploring (but has not yet determined) whether DR would be economic for deferring several pending base capex investments relative to the planned investment.

## **The Commerce Commission regulates expenditure on major projects**

- C.9 The regulatory regime for Transpower treats projects with expected capital expenditure of \$20 million or more for enhancement and development of the grid as being outside the predefined revenue allowance for each control period. These projects are referred to as major capex.
- C.10 Transpower's use of non-transmission solutions (including distributed generation) to defer major capex investment is regulated under the consolidated Transpower capital expenditure input methodology determination (Capex IM).<sup>80</sup>
- C.11 For Transpower to recover the costs of contracting a non-transmission solution for major capex investment, it must obtain Commerce Commission approval for a non-transmission solution just as it does for a transmission solution.<sup>81</sup>
- C.12 Transpower is required to consider, and consult on, non-transmission solutions as alternatives to major capex investment.<sup>82</sup> Transpower has published an

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<sup>79</sup> Payments to generators are one of a range of transmission alternatives that could also include payments to load (as per Transpower's DR programme), energy efficiency, and non-investment transmission solutions (e.g. implementing variable line rating on a line).

<sup>80</sup> <http://comcom.govt.nz/dmsdocument/13004>

<sup>81</sup> See clause 3.1.3 (1) (c) of the Transpower IM.

<sup>82</sup> See clause 8.1.3, and Schedule I Division 2, of the Capex IM.



investment approvals process document that sets out how it will consider non-transmission solutions.<sup>83</sup>

- C.13 To date, Transpower has not used a non-transmission solution to defer any investment costing over \$20 million. However, the Authority understands that Transpower considers there is genuine potential for transmission alternatives, in particular DR, to efficiently defer transmission investment. DR may include a distributed generation component.
- C.14 As an example, Transpower is currently considering non-transmission solutions to defer or reduce the need for reliability investment to serve Wiri and Bombay. In November 2014 Transpower issued a request for information (RFI) for non-transmission solutions in this region.<sup>84</sup>

### **Transpower operates a Demand Response programme**

- C.15 Transpower operates a Demand Response (DR) programme, which covers both demand that can be directly managed, and reductions in net demand via use of controllable distributed generation. The DR programme is intended to further develop Transpower's capability to procure and direct DR for the purpose of managing demand on the transmission network.<sup>85</sup>
- C.16 Transpower has published a DR protocol that describes:<sup>86</sup>
- (a) how Transpower will operate while carrying out the work included in its DR programme
  - (b) how Transpower and the Authority will work to ensure that Transpower's development of DR does not adversely affect the wholesale electricity market.
- C.17 The DR protocol sets out that Transpower:
- (a) has committed to open and transparent development of its DR programme
  - (b) will work to lower barriers to entry for potential transmission alternative proponents to participate in the transmission alternatives market
  - (c) will always consider the use of transmission alternatives in investment decision making.
- C.18 Projects carried out to date under Transpower's DR programme have included:

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<sup>83</sup> [https://www.transpower.co.nz/sites/default/files/plain-page/attachments/investment-approvals-process\\_0.pdf](https://www.transpower.co.nz/sites/default/files/plain-page/attachments/investment-approvals-process_0.pdf)

<sup>84</sup> [https://www.transpower.co.nz/sites/default/files/uncontrolled\\_docs/OTA-WIR%20long%20list%20and%20RFI%20consultation.pdf](https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/OTA-WIR%20long%20list%20and%20RFI%20consultation.pdf)

<sup>85</sup> <https://www.transpower.co.nz/about-us/demand-response>

<sup>86</sup> [https://www.transpower.co.nz/sites/default/files/uncontrolled\\_docs/Demand-Response-Operational-Protocol.pdf](https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Demand-Response-Operational-Protocol.pdf)

- (a) trialling DR to manage USI peak demand in 2007 and 2008 <sup>87</sup>
  - (b) trialling DR to manage UNI peak demand in 2012 and 2013 <sup>88</sup>
  - (c) trialling DR nationwide, focusing on large electricity users and smaller business consumers, in 2013. <sup>89</sup>
- C.19 In the course of these projects, Transpower has gained experience in:
- (a) contracting existing distributed generation to operate at peak times <sup>90</sup>
  - (b) contributing to the funding of new distributed generation. <sup>91</sup>
- C.20 Transpower is continuing to trial DR, <sup>92</sup> with a current focus on these consumer types:
- (a) agribusiness
  - (b) campus-style organisations
  - (c) battery technology
- and these locations (all of which are currently facing a possible need for transmission investment):
- (a) Otahuhu, Wiri and surrounding areas
  - (b) Timaru, Temuka and surrounding areas
  - (c) Oamaru and surrounding areas.
- C.21 The development of Transpower's DR programme over 2012-15 was funded by a \$12M allocation for transmission alternatives.
- C.22 Transpower has been granted an opex allowance of \$8 million over 2015-20 to fund the fixed costs of its DR programme. In the Commerce Commission's words,

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<sup>87</sup> See eg <http://www.scoop.co.nz/stories/BU0705/S00212/transpower-announces-new-demand-side-trial.htm>, <http://www.stuff.co.nz/business/450393/Transpower-repeats-trial-to-reduce-power-demand>

<sup>88</sup> See eg <http://www.epecentre.ac.nz/docs/media/Systems%20to%20Implement%20Demand%20Response%20in%20NZ-EEA%20conf%202014.pdf>

<sup>89</sup> See eg [https://www.transpower.co.nz/sites/default/files/uncontrolled\\_docs/Demand%20Response%20Programme%20Report%20Summary.pdf](https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Demand%20Response%20Programme%20Report%20Summary.pdf)

<sup>90</sup> See eg [https://www.transpower.co.nz/sites/default/files/uncontrolled\\_docs/Demand%20Response%20Programme%20Report%20Summary.pdf](https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Demand%20Response%20Programme%20Report%20Summary.pdf)

<sup>91</sup> See eg <https://www.transpower.co.nz/about-us/demand-response/demand-response-resources/case-study-using-generators-demand-response>

<sup>92</sup> <https://www.transpower.co.nz/about-us/demand-response/our-current-demand-response-programme>

this allowance 'is not direct funding to defer any transmission investment, and is intended to develop and grow demand response capability'.<sup>93</sup>

## **The Commerce Commission can reopen a determination**

- C.23 The regulatory arrangements are intended to provide incentives for Transpower to operate efficiently. They do this by providing that Transpower can retain a sizeable proportion of any efficiencies during each control period. These efficiencies can then be taken into account when resetting revenue allowances for the next period. Similarly, Transpower faces incentives to manage any unexpected costs because it will need to absorb a proportion of such increases.
- C.24 There are also provisions that allow the Commission to reopen a determination in limited circumstances. In particular:
- (a) Section 54V(5) of the Commerce Act provides that if asked by the Authority, the Commerce Commission must reconsider a section 52P determination, and to the extent that the Commission considers it necessary or desirable to do so, amend the determination. This provides an avenue for a Commerce Commission determination relating to a price-quality path to be reconsidered, if that was thought to be desirable, for a limited range of matters.
  - (b) The Transpower input methodologies (subpart 7) allow the revenue allowance to be reconsidered if a 'change event' is triggered. Change event means a change in, or new, legislative or regulatory requirement applying to Transpower which necessitates incursion of additional costs which are at least equivalent to 1% of the aggregated forecast maximum allowable revenues for the relevant years.

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<sup>93</sup> <http://www.comcom.govt.nz/dmsdocument/12336>

## Appendix D Economic benefits of proposal (ACOT issue)

- D.1 This Appendix sets out the methodology used by the Authority to estimate the economic benefits of the proposal in terms of its ability to address the ACOT issue. The Appendix does not address the estimated economic costs of the proposal, which are set out in the main text of the paper (from para 4.5.25).
- D.2 The approach taken in this Appendix is to estimate economic benefits on a ‘\$million per year’ basis, and then (in the concluding table) to aggregate them into ‘\$million present value over 15 years’ terms.
- D.3 The Authority has considered the following potential economic benefits.
- (a) reducing inefficient, out-of-merit **operation** of distributed generation and notionally embedded generation that does not reduce or defer transmission investment costs
  - (b) reducing the scope for **retention** of distributed generation and notionally embedded generation that does not reduce or defer transmission investment costs and whose retention is not justified by other benefits (such as local or market-wide reliability)
  - (c) reducing inefficient, out-of-merit **investment** in new distributed generation or notionally embedded generation that does not reduce or defer transmission investment costs
  - (d) reducing the **allocative efficiency** losses associated with consumers paying electricity prices that are higher than is necessary, and altering their consumption decisions as a result.
- D.4 The Authority has evaluated each of these benefits under two different TPM “future state” options:
- (a) ‘current TPM’ – in which the current TPM remains in force (with changes resulting from the Transpower operational review of the TPM applying to calculation of transmission charges from 1 April 2017). This option is likely to drive incentives in the 2015/16 and 2016/17 capacity measurement periods (which would be used to set transmission prices for the 2017/18 and 2018/19 pricing years). This option may also drive incentives over a longer period
  - (b) ‘area-of-benefit-based TPM’ – in which transmission investment costs are allocated to the beneficiaries of each investment. Any residual charges will be allocated to load customers based on their capacity. This scenario could drive incentives from the 2017/18 capacity measurement period onwards.
- D.5 The following subsections describe the four sources of potential economic benefit.

## Avoiding inefficient, out-of-merit operation of generation

- D.6 This subsection deals with the economic costs that can be incurred when generators operate in order to receive ACOT payments even though:<sup>94</sup>
- (a) their short-term marginal cost (SRMC) exceeds the marginal value of energy at the time
  - (b) their operation does not defer or reduce the cost of network investment.

### *Current TPM*

- D.7 The combination of the current DGPPs and the current TPM can result in inefficient operation of generation. Some distributed generation, and some grid-connected generation that is notionally embedded, seek to operate in potential regional peak periods, in order to receive ACOT payments from their distributor.
- D.8 The Authority considers that such operation:
- (a) will almost always be efficient for existing geothermal and wind generation, which has a very low SRMC
  - (b) will usually be broadly efficient for existing hydro and gas-fuelled generation, whose SRMCs are unlikely to greatly exceed the marginal value of energy at peak times
  - (c) can be inefficient for existing liquid-fuelled generation, whose SRMC may considerably exceed the marginal value of energy at peak times – except in cases where such operation defers or reduces the cost of network investment.
- D.9 Transpower's recent operational review of the TPM sought to reduce the incentive for inefficient operation of distributed generation (among other things), by basing the RCPD charge on 100 coincident peak periods per year in the UNI and USI. Previously this charge was based on twelve peak periods. Despite this change, RCPD still creates a substantial incentive for operation in potential peak periods – in excess of \$1,100/MWh.<sup>95</sup>
- D.10 Most distributors pass this incentive on to generators that meet their requirements for receiving ACOT, though some pass it on in a diluted form.
- D.11 The Authority expects that the proposal would remove this incentive, at least:
- (a) for generators that receive ACOT payments under the DGPPs

<sup>94</sup> The costs considered in this paragraph are the costs of operating distributed generation inefficiently, as opposed to the costs of the proposal (which are not considered in this appendix).

<sup>95</sup> An RCPD charge of \$110/kW, calculated over 100 half hours per year, creates an incentive of  $\$110/\text{kW} * 1000 / (100 * 0.5 \text{ hours}) = \$2,200/\text{MWh}$  in each of those half hours. Even if a generator finds it needs to operate in 200 half hours per year in order to be sure of 'hitting' all 100 regional peak periods, the incentive is still \$1,100/MWh.

- (b) for some new distributed generation and notionally embedded generation
- (c) for most generators whose distributor is subject to price control.

D.12 The Authority estimates the resulting economic benefit as:

$$B = Q_{\text{liq}} \times P_{\text{no\_deferral}} \times R \times (\text{SRMC} - V_e) \times N_{\text{hh}} / 2$$

Where:

B is economic benefit, in real \$ per year

$Q_{\text{liq}}$  is the average amount of liquid-fuelled generation that operates in potential RCPD periods, in MW

$P_{\text{no\_deferral}}$  is the proportion of such operation that is inefficient, in that it does not defer or reduce the cost of network investment

R is the percentage reduction in such operation as a result of the proposal

SRMC is the average short-term marginal cost of such liquid-fuelled generation, in \$/MWh

$V_e$  is the average value of energy in potential RCPD periods, in \$/MWh

$N_{\text{hh}}$  is the number of potential RCPD periods in which such generation operates, in order to 'hit' the N=100 actual RCPD periods.

D.13 For this purpose, the Authority assumes that:

- (a)  $Q_{\text{liq}}$  is 10 MW (on the basis of responses to its recent survey of distributors)
- (b) SRMC is \$300/MWh<sup>96</sup>
- (c)  $V_e$  is \$100/MWh (a rough approximation to the mean wholesale spot price in regional peak periods)
- (d)  $N_{\text{hh}}$  is 150.<sup>97</sup>

D.14 B = \$22,500 per year with the following assumptions:

- (a)  $P_{\text{no\_deferral}} = 30\%$  (ie the majority of such operation supports network deferral) and
- (b) R = 50% (ie the proposal is only successful in halving the amount of inefficient operation).

D.15 B = \$84,000 per year with the following assumptions:

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<sup>96</sup> Consistent with Appendix I of <http://www.ea.govt.nz/dmsdocument/19327> .

<sup>97</sup> Consistent with Appendix I of <http://www.ea.govt.nz/dmsdocument/19327> .

- (a)  $P_{\text{no\_deferral}} = 70\%$  (ie the majority of such operation does not support network deferral) and
- (b)  $R = 80\%$  (ie the proposal considerably reduces the amount of inefficient operation).

D.16 The Authority therefore estimates the economic benefit of the proposal, relative to the current DGPPs, in terms of avoiding inefficient operation, under the current TPM, as being in the range of \$0.02-0.08 million per year.

***Area-of-benefit-based TPM***

D.17 The Authority does not expect that an area-of-benefit-based TPM, under the current DGPPs, would create a material incentive for inefficient operation of controllable generation. This is because the primary allocator is designed to minimise any incentive effect on generation operations. However, it is not possible to rule out entirely some effect on incentives.

D.18 In respect of the residual capacity allocator, it is possible that the operation of distributed generation could affect the capacity required by a load for connection to the grid and hence of this allocator. Therefore, under the combination of the current DGPPs and area-of-benefit-based TPM, some distributed generators could receive ACOT payments from distributors. The calculation of these payments would not take into account whether the distributed generation actually reduced or deferred transmission costs.

D.19 For the reasons set out above, an area-of-benefit-based TPM, under the current DGPPs, could create some incentive for inefficient operation of controllable distributed generation.

D.20 The Authority has not estimated the scale of the ACOT payments that might be made, or the inefficiencies that might result, in these circumstances. However, the Authority expects that because the residual under the proposed TPM is set on the basis of lagged capacity, any inefficiency would be small. As a result, the economic cost of the inefficiencies in this scenario would be significantly lower than the economic cost under the current TPM.

**Bringing forward closure of uneconomic generation**

D.21 This subsection deals with the economic costs that can be incurred when existing distributed generation and notionally embedded generation is retained in service, funded in part by ACOT payments, even though:

- (a) operating and maintenance (O&M) costs mean that it is not cost-efficient and/or
- (b) its operation does not defer or reduce the cost of network investment and other benefits do not justify its retention.

***Current TPM***

- D.22 The combination of the current DGPPs and the current TPM can potentially result in inefficient retention of distributed generation and notionally embedded generation. Investors can have an incentive to keep generation that earns ACOT in service, even if it is not economic.
- D.23 The Authority is not aware of any specific situation where generation is being kept in service by ACOT payments, but considers that it is possible that such a situation is occurring or could occur in future.
- D.24 The Authority expects that the proposal would remove this incentive, at least:
- (a) for generators that receive ACOT payments under the DGPPs
  - (b) for most generators whose distributor is subject to price control.
- D.25 The Authority estimates the resulting economic benefit as
- $$B = Q_{DG} \times P_{no\_deferral} \times P_{kept\_in\_service} \times PD \times R$$
- Where:
- B is economic benefit, in real \$ per year
- $Q_{DG}$  is the expected amount of distributed generation that receives ACOT payments, under the current DGPPs, in MW
- $P_{no\_deferral}$  is the proportion of such investment that is inefficient, in that it does not defer or reduce the cost of network investment
- $P_{kept\_in\_service}$  is the proportion of that investment that is uneconomic and only kept in service by ACOT payments
- PD is the average difference in costs between such investments and the best available new alternative, in \$/MW per year
- R is the percentage reduction in such retention as a result of the proposal.
- D.26 For this purpose, the Authority assumes that:
- (a)  $Q_{DG}$  is 800 MW (based on responses to its recent survey of distributors)
  - (b) PD is \$10/kW (conservatively).
- D.27 The Authority cannot rule out that  $P_{kept\_in\_service}$  is nil. Thus, the lower bound estimate of the estimated inefficiency is nil.
- D.28 However,  $B = \$450,000$  per year with the following assumptions:
- (a)  $P_{no\_deferral} = 70\%$  (ie most generation receiving ACOT does not support network deferral)



- (b)  $P_{\text{kept\_in\_service}} = 10\%$  (ie 10% of such generation is inefficiently kept in service by ACOT payments) and
- (c)  $R = 80\%$  (ie the proposal considerably reduces the amount of retained inefficient generation).

D.29 The Authority therefore estimates the economic benefit of the proposal, relative to the current DGPPs, in terms of avoiding inefficient retention of distributed generation, under the current TPM, as being in the range of \$0 – 0.45 million per year.

***Area-of-benefit-based TPM***

D.30 For the reasons set out in paragraphs D.18 and D.19, an area-of-benefit-based TPM, under the current DGPPs, could create an incentive for inefficient retention of distributed generation and notionally embedded generation.

D.31 The Authority has not estimated the scale of the ACOT payments that might be made, or the inefficiencies that might result, in these circumstances. However, the economic cost of the inefficiencies in this scenario would be significantly lower than the economic cost under the current TPM.

**Avoiding inefficient, out-of-merit investment in new generation**

D.32 This subsection deals with the economic costs that can be incurred when new distributed generation or notionally embedded generation is constructed, justified in part by ACOT payments, even though:

- (a) its long-run marginal cost (LRMC) exceeds the LRMC of some other generation that could have been constructed instead, and
- (b) its operation does not defer or reduce the cost of network investment.

***Current TPM***

D.33 The combination of the current DGPPs and the current TPM can result in inefficient investment in distributed generation or notionally embedded generation. Investors have an incentive to proceed with generation options that can be embedded, or notionally embedded, and can obtain ACOT payments. Investment will be inefficient where such generation is less cost-effective than the best available grid-connected alternative.

D.34 Transpower's recent operational review sought to reduce the incentive for inefficient investment in distributed generation and notionally embedded generation, by moving to 100 coincident peak periods per year in the UNI and USI

regions. This change may deter some inefficient investment in peaking thermal distributed generation, but does not deter renewable distributed generation.<sup>98</sup>

- D.35 Most distributors pass this incentive on to generators that meet their requirements for receiving ACOT, though some pass it on in a diluted form.
- D.36 The Authority expects that the proposal would largely remove this incentive.
- D.37 The Authority estimates the resulting economic benefit as:

$$B = Q_{DG} \times P_{no\_deferral} \times P_{out\_of\_merit} \times PD \times R$$

Where:

B is economic benefit, in real \$ per year

$Q_{DG}$  is the expected amount of distributed generation that will be constructed per year, partly or wholly funded by ACOT payments, under the current DGPPs, in MW

$P_{no\_deferral}$  is the proportion of such investment that is inefficient, in that it does not defer or reduce the cost of network investment

$P_{out\_of\_merit}$  is the proportion of that investment that is less cost-effective than the best available grid-connected alternative

PD is the average difference in capital cost between such investments and the best available grid-connected alternative, in \$/MW

R is the percentage reduction in such operation as a result of the proposal.

- D.38 For this purpose, the Authority assumes that:
- (a)  $Q_{DG}$  is 20 MW (broadly consistent with experience in recent years, as revealed by responses to its recent survey of distributors)
- (b) PD is \$250/kW.<sup>99</sup>
- D.39 B = \$180,000 per year with the following assumptions:

<sup>98</sup> The move to 100 coincident peak periods per year does not change the expected ACOT payments received by a baseload or intermittent generator, and reduces the volatility of payments from year to year. Overall, this change is advantageous to the generation investor.

<sup>99</sup> Consider two potential wind generation projects, A and B, both with expected load factors of 40%. Suppose A can be embedded and can receive ACOT payments, while B cannot. All else being equal, then if A and B have the same expected capital costs, then A will be more attractive to the developer – because it will receive an expected \$110/kW x 40% = \$44/kW per year, or roughly \$450/kW present value. But if the capital cost of A exceeds that of B by \$500/kW, then B will be more attractive to the developer. The assumption that PD is \$250/KW reflects a scenario that is halfway between these two extremes – in which B is more economic than A, but a developer is likely to prefer A in order to obtain ACOT payments.

- (a)  $P_{\text{no\_deferral}} = 30\%$  (ie the majority of such investment supports network deferral)
- (b)  $P_{\text{out\_of\_merit}} = 30\%$  (ie the majority of distributed generation investment that does not support network investment is nevertheless cost-efficient) and
- (c)  $R = 40\%$  (ie the proposal is successful in nearly halving the amount of inefficient operation).

D.40  $B = \$1,800,000$  per year with the following assumptions:

- (a)  $P_{\text{no\_deferral}} = 70\%$  (ie most such investment does not support network deferral)
- (b)  $P_{\text{out\_of\_merit}} = 80\%$  (ie most such investment is less cost-efficient than the best grid-connected alternative) and
- (c)  $R = 65\%$  (ie the proposal considerably reduces the amount of inefficient investment).

D.41 The Authority therefore estimates the economic benefit of the proposal, relative to the current DGPPs, in terms of avoiding inefficient investment, under the current TPM, as being in the range of \$0.18 – 1.8 million per year.

***Area-of-benefit-based TPM***

D.42 For the reasons set out in paragraphs D.18 and D.19, an area-of-benefit-based TPM, under the current DGPPs, could create an incentive for inefficient investment in distributed generation and notionally embedded generation.

D.43 The Authority has not estimated the scale of the ACOT payments that might be made, or the inefficiencies that might result, in these circumstances. However, the economic cost of the inefficiencies in this scenario would be significantly lower than the economic cost under the current TPM.

**Avoiding allocative efficiency losses from higher prices for consumers**

D.44 This section deals with the loss to consumers caused by electricity prices being higher than otherwise in order to fund inefficient ACOT payments.

D.45 As discussed in section 3,<sup>100</sup> it appears likely that consumers are being required to pay an additional cost of approximately \$25 million - \$35 million per annum to fund ACOT payments without receiving an associated benefit.

D.46 While this is a transfer from consumers to some distributed generation and embedded generation owners in the first instance, this will also create efficiency losses by raising electricity prices to end-consumers, thereby distorting their consumption decisions.

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<sup>100</sup> See para 3.3.21.

D.47 The additional average cost of electricity is approximately \$0.6/MWh to \$0.9/MWh across all users. The efficiency loss equates to \$120k to \$170k in present value terms, based on an estimated price elasticity of demand of -0.26 and total national usage of 40 TWh per year.

### Combining all four sources of benefit

D.48 Table 9 shows the estimated economic benefit of the proposal, relative to the current DGPPs, under each of the two TPM scenarios.

Table 9: Combining of all four sources of benefit

TPM option	Estimated economic benefit relative to the current DGPPs, in real \$million per year				
	Avoiding inefficient, out-of-merit operation of distributed generation	Bringing forward closure of uneconomic distributed generation	Avoiding inefficient, out-of-merit investment in new distributed generation	Avoiding allocative loss	Combined
Current TPM	0.02 – 0.08	0 – 0.45	0.18 – 1.8	0.01 – 0.02	0.22 – 2.37
Area-of-benefit-based TPM	~0*	~0*	~0*	0.01 – 0.02	0.01 – 0.02

\* ~0 represents an unquantified, small positive number

D.49 Table 10 aggregates the ‘\$million per year’ estimates in Table 9 into ‘\$million present value over 15 years’ terms, using two scenarios:

- (a) in which the current TPM remains in force
- (b) in which a new area-of-benefit-based TPM comes into force in 2019.

D.50 A 6% real discount rate is used.

D.51 To reflect the proposed two-phase transition to the proposed new ACOT payment regime, the Authority has made the following assumptions have been made for phasing of benefits when calculating the present value over 15 years:

- (a) The estimated annual benefit from avoiding inefficient out-of-merit operation of distributed generation would not start accruing until the transition is completed (ie the benefit accrues annually from 1 April 2018 onwards).

- (b) The estimated annual benefit of bringing forward closure of uneconomic distributed generation is derated by 50% for the first year of the transition (ie for the year beginning 1 April 2017) because the proposed new ACOT regime would only be in force for two of the four regions in that year.
- (c) The estimated annual benefit of avoiding inefficient out-of-merit investment in new distributed generation would begin to accrue once the Authority makes the Code amendment implementing the proposed new ACOT payment regime. The proposed two-phase transition therefore does not affect the present value calculation over 15 years.
- (d) The estimated annual benefit of avoiding allocative loss is derated by 50% for the first year of the transition (ie for the year beginning 1 April 2017) because the proposed new ACOT regime would only be in force for two of the four regions in that year.

D.52 The Authority has also calculated the gross benefit to consumers expected from the proposal. The Authority does not take into account changes in consumer (or producer) surplus – it is only concerned with efficiency. The gross benefit to consumers is included here for the purposes of information only, as it may be a relevant consideration for other policy makers and stakeholders.

D.53 The gross benefit to consumers is based on the estimated range for ACOT payments without an associated transmission benefit, as set out in paragraph 3.3.21. Under the proposal, the Authority expects that distributors would no longer recover such payments from consumers.

D.54 The assessment of gross benefits to consumers is based on a 15-year period, with benefits discounted at 6% per annum. For the scenarios in which a new TPM is assumed to come into force in 2019, consumer benefits from that date have not been quantified as there is currently insufficient information available to estimate the effects.

Table 10: Economic benefits, and gross benefits resulting from the proposal, relative to the current DGPPs

	<b>Expected economic benefits, in \$million present value terms</b>	<b>Gross benefit to consumers, in \$million present value terms</b>
Current TPM	2.0 – 21.7	232 – 325
Current TPM for two years from April 2017, then area-of-benefit-based TPM	0.5 – 4.2	46 – 64 plus effect after 2019 (not quantified)

- D.55 As it is central to the case for change, the above table is reproduced twice in the main text of the paper, as Table 1 in the Executive Summary and also as Table 4 in section 4.5.

## Appendix E Two options the Authority rejected

### ***Rejected option A – Keep current DGPPs under a new TPM***

- E.1 The Authority considered keeping the current DGPPs, with the intention that:
- (a) The TPM would provide for an area-of-benefit charge and a capacity-based residual charge.
  - (b) Each distributor would ‘look ahead’ to identify potential transmission investments they would use or benefit from, and hence would pay for if they went ahead.
  - (c) The distributor would consider contracting for investment in, or operation of, distributed generation to defer the need for these potential transmission investments. This would defer the increase in the distributor’s transmission *charges* that would occur once Transpower commissioned the transmission investment(s).
- E.2 The Authority considers that there would be a significant impediment to distributors and owners of distributed generation agreeing to such contracts. This is because they are unlikely to have the full information needed to determine what transmission investments might be required, and how the operation of distributed generation could defer the investment.
- E.3 One consequence of this lack of information would be that distributors could not be confident that Transpower would actually defer the transmission investment(s) as a result of the operation of the distributed generation.
- E.4 Further, it would be difficult to ensure that the Commerce Act regime:
- (d) allowed distributors subject to price control to recover the cost of efficient payments made to distributed generators under such contracts, but
  - (e) did not allow such distributors to recover the cost of inefficient payments
- because neither distributors nor the Commerce Commission would be best placed to determine which payments were efficient.
- E.5 Another disadvantage of this option is that it would not help to mitigate the inefficient outcomes that can occur under the combination of the current DGPPs and the current TPM should the current TPM be retained.
- E.6 The Authority concludes that this option would not promote the Authority’s statutory objective in section 15 of the Act.

### ***Rejected option B – Define ‘incremental cost’ in terms of avoided transmission costs***

- E.7 The Authority considered amending the definition of ‘incremental cost’ in the DGPPs to refer to avoided transmission *costs* rather than avoided transmission

*charges*. In other words, the regulated terms would provide for a distributor to pay distributed generators for any efficient deferral or reduction of transmission costs achieved by the operation of distributed generation.

- E.8 However, the Authority considers that distributors and distributed generation owners are unlikely to have the information and analytical tools needed to properly assess the impact of distributed generation on transmission costs. Therefore, it is likely that this option would result in distributors making ACOT payments to distributed generators that were not reflective of avoided transmission costs.
- E.9 The Authority concludes that this option would not promote the objective set out in section 15.