Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation

Working Paper

19 November 2013

826957-1

1 Executive summary

Introduction

1.1 The pricing principles in Schedule 6.4 of the Electricity Industry Participation Code 2010 (Code) require electricity distributors (distributors) to pay distributed generators (DG) for reductions in transmission and distribution costs that arise from connecting DG to their network. These cost reductions are often termed the Avoided Cost of Transmission (ACOT).

1.2 A practice has arisen whereby a majority of distributors calculate their ACOT payments according to the transmission <u>charges</u> they avoid (as a result of the operation of DG on their network) rather than on the basis of the economic <u>costs</u> avoided.

1.3 This practice has led some industry participants, many of them DGs, to express concern about the Electricity Authority's (Authority's) proposal to reduce transmission charges faced by distributors, as doing so would reduce ACOT payments and detrimentally affect DGs (if most distributors continue to calculate ACOT payments based on avoided transmission charges).

1.4 The Authority is conducting a review of the Transmission Pricing Methodology (TPM) contained in schedule 12.4 of the Code. The Authority is developing its response to submissions and cross submissions on the consultation paper 'Transmission Pricing Methodology: issues and proposal' dated 10 October 2012 (October issues paper), and to points raised in the May 2013 TPM conference.

1.5 The purpose of this working paper, therefore, is to assist the Authority to understand the efficiency implications of any changes to the TPM in relation to ACOT payments.

1.6 To do this, the paper:

(a) assesses the extent that ACOT payments influence transmission and distribution investment

(b) assesses whether ACOT payments provide other benefits.

1.7 If ACOT payments reduce the need for transmission and distribution investment, then changes to the TPM that reduce ACOT payments may be inefficient. Conversely, if ACOT payments do not reduce transmission and distribution investment then TPM changes that reduce ACOT payments may improve efficiency.

The approach used in this working paper

1.8 This paper splits distributed generation into two categories: larger distributed generators (DG) and small scale DG (SSDG), where the latter is less than 10kW and is typically operated at the household level. The two categories allow for separate consideration of the treatment of ACOT payments for each category.

1.9 The paper examines distributors' ACOT payment policies and Transpower's treatment of DG, and investigates the influence that DG investments have on Transpower's investment decisions.

1.10 The paper also examines whether ACOT payments provide an effective locational signal and whether recently commissioned DG has been located in import constrained regions.

1.11 This paper also assesses non-transmission related costs and benefits that may arise from DG, including in relation to electricity distribution. The paper considers whether market mechanisms provide adequate compensation to DG for any other benefits it provides.

Preliminary findings regarding ACOT payments

1.12 Of the 29 distributors, 23 have an ACOT payment policy in place and six do not. Of the 23 distributors who have an ACOT payment policy, 18 of the policies provide for payments to DG based on avoided transmission charges.

1.13 The other five policies are based on other types of approaches, including avoided costs to the distributor, for example, paying DG an amount representing the value of the reduction in the network's long run average incremental cost (LRAIC) resulting from the DG.

1.14 The available information on ACOT payments identifies that approximately $50 million will be paid to 766 MW of qualifying generation during 2013/14. This is equivalent to $650,000/MW in present value terms, which is likely to represent a substantial portion of the capital costs of DG. This estimate of the total ACOT payments covers payments by distributors ranging from less than $100,000 to more than $10 million.

1.15 As a result of the analysis described in this paper, the Authority's preliminary conclusions in relation to ACOT payments to DG are:

(a) amongst the DG projects, there does not appear to be strong evidence indicating that DG location has been determined by avoidance of a transmission investment rather than access to a suitable site or resource. ACOT payment rates are largely identical across distribution networks. There is not a strong link between the ACOT payment and location of DG to either relieve congestion and/or provide an alternative to transmission

(b) ACOT payments, and the existence of DG, appears to have no observed effect on transmission investments

(c) although there appear to be some exceptions, ACOT payments have little observed effect on distribution investments or costs, and ACOT payments appear to provide no other material benefits to distributors

(d) a prevalence of DG on some distribution networks can cause net costs to the distributor

(e) the benefits of DG to distributors should increase as energy storage capability improves

(f) ACOT payments do not appear to deliver any other material economic benefits

(g) given the Transpower interconnection charges are a cost recovery mechanism (to recover approximately $546 million for 2013/14), collectively, all connected consumers are paying both the full Transpower charge plus the full cost of the ACOT payments for a total cost of approximately $600 million. That is, the ACOT payments appear to have increased costs to consumers. ACOT is estimated to cost consumers $10 per household p.a.[1]

1.16 The Authority considers that an approach in which payments to DGs are based on avoided economic costs, rather than avoided transmission charges to the distributor, would better reflect the Authority's statutory objective[2] "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers". This would include consideration of avoided costs to both transmission and distribution.

1.17 On this basis, the Authority's preliminary view is that the majority of ACOT payment schemes could be improved through:

- a greater focus on economic costs rather than the pass through of avoided transmission charges to consumers
- a greater consideration of any benefits accruing to distribution networks, if any.

1.18 The Authority's preliminary view is that a review of the provisions of Schedule 6.4 is therefore warranted with a view to ensuring a stronger link between ACOT payments and efficiency benefits. Further, the review should consider whether ACOT payments could be better targeted to where market failures occur, for example to capture the value of distribution costs avoided as a result of DG, if any, and where payment to DG for these benefits would not occur in the absence of regulation.

1.19 Non-transmission- and distribution-related benefits appear to be, at least partly, compensated for through other market mechanisms, such as the ETS for emission reduction benefits and nodal pricing in the wholesale market for reduction in losses and constraints on the transmission network resulting from DG.

1.20 If current market mechanisms or the Code do not provide for adequate compensation for benefits provided by DG, and these benefits are recognised in the Authority's statutory objective, the Authority would consider amending the Code to provide for DG to receive compensation for these benefits to the extent that it is efficient. To the extent that these benefits are not recognised by the Authority's statutory objective, the Authority would provide information it receives on this to the relevant regulating authority or government department.

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1 Based on an assumption that ACOT does not reduce or avoid transmission or distribution costs, $50 million ACOT per annum divided by total electricity consumption of 38,865,916 MWh = $0.00128/ KWh x 8000 KWh (average' household consumption) = $10.29 per household.

2 s15, Electricity Industry Act 2010.

1.21 The Authority considers that such a review could be conducted separately from, but potentially in parallel to, the review of the TPM.

1.22 Depending on the potential impact of any changes to the Code that results from a review of the part 6 pricing principles, it may be desirable to include transitional arrangements. However this is not within the scope of this paper. The need for, and nature of, any transitional arrangements will be considered at the time that part 6 is reviewed.

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2 Introduction

Background to process

2.1 The Electricity Authority (Authority) is reviewing the transmission pricing methodology (TPM), which specifies the method for Transpower New Zealand Limited (Transpower) to recover costs of operating, maintaining, upgrading and extending the transmission grid.

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

Working papers

2.3 The Authority has decided to advance the process of reviewing the TPM by developing a second TPM issues paper (second issues paper) following consideration of submissions on the October 2012 TPM issues paper (October issues paper) and information provided at the TPM conference held in Wellington on 29-31 May 2013.

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

2.5 This paper is the third of the series of working papers identified by the Authority.

Background to this working paper

2.6 Following consideration of submissions on the October issues paper and the responses of parties to the Authority's questions at the May 2013 TPM conference, the Authority decided to prepare a working paper to understand the implications of changes to the TPM that may reduce the quantum of ACOT payments.

2.7 The pricing principles in Schedule 6.4 of the Electricity Industry Participation Code 2010 (Code) govern the way that DGs are charged for connecting to a distributor's network. Under the pricing principles, those charges are based on the incremental cost of providing connecting services to the DG, net of any transmission and distribution costs that the distributor could avoid due to the connection of the DG (see paragraph 2(a) of Schedule 6.4). If the incremental cost is negative, the DG can invoice the distributor, because the DG is deemed to be providing network support (see paragraph 2(e) of Schedule 6.4). The incremental cost is based on a 'with and without' test – the distributor must consider how the distributor's capital investment decisions and operating costs would differ in the future, with and without the DG.

2.8 Clause 2(b) states that costs that cannot be calculated (for example avoidable costs) must be estimated based on a reasonable estimate of how the distributor's capital investment and operational costs would differ with and without the DG.

2.9 "Avoided Cost of Transmission" (ACOT) payments to DG have emerged as the convention to meet the Schedule 6.4 pricing principles. A majority of distributors calculate ACOT payments according to the generation by DG during regional coincident peak demand (RCPD) periods, the periods used to calculate distributors' liability for the interconnection charge under the TPM.

2.10 Some industry participants raised concerns that proposed changes to the TPM would alter the level of ACOT payments that many DGs currently receive, and rely on in order for their businesses to remain commercially viable. More specifically, these parties were concerned that introducing other charges, such as the SPD charge and regional coincident peak injection (RCPI) charge, would reduce the RCPD charges for distributors and therefore reduce ACOT payments to DG. These parties were also concerned that the 'opt out' option in the 2012 TPM proposal, which could result in RCPD charges levied directly on retailers, would also reduce ACOT payments to DG.

2.11 These parties' concerns are based on an assumption that ACOT payment policies would continue to rely on RCPD information, rather than be able to be adapted to reflect alternative charging methods. This paper does not consider or assess whether ACOT payments, as currently calculated, comply with Schedule 6.4. For the purposes of the analysis in this paper, the Authority assumes that such charges do comply. This assumption is not, however, material to the analysis in this paper.

Purpose of this working paper

2.12 The purpose of this working paper is to assist the Authority to understand the implications of changes to the TPM that may reduce the quantum of ACOT payments, assuming the current ACOT payment policies are maintained.

2.13 To do this, the paper:

(a) assesses the extent that ACOT payments influence transmission and distribution investment

(b) assesses whether ACOT payments provide other economic benefits.

2.14 If ACOT payments reduce the need for transmission and distribution investment, then changes to the TPM that impact the quantum of ACOT payments may be inefficient. However, if ACOT payments do not change or increase transmission and distribution investment, then changes to the TPM that impact ACOT payments may actually improve efficiency.

Other working papers

2.15 Other working papers the Authority has identified include:

(a) Cost benefit analysis (CBA) – This paper outlined a revised approach that the Authority intends to apply to the cost benefit analysis of a revised TPM proposal that will be included in the second issues paper. (Submissions closed)

(b) Definition of sunk costs – This paper examined the extent to which the costs involved in the provision of electricity transmission services are actually "sunk" and the implications for transmission pricing. (Submissions close 5pm on 19 November 2013.)

(c) Use of loss and constraint excess (LCE) to offset transmission charges – This paper will explore submitter suggestions that the proposed use of LCE to offset transmission charges would distort the otherwise efficient wholesale market signals. (Future consultation)

(d) Approach to residual charge - This paper will consider whether it may be efficient to levy any residual charge on the basis of congestion rather than load during peak demand periods. (Future consultation)

(e) Beneficiaries-pay approach – This paper will examine options for applying a beneficiaries-pay charge. (Future consultation)

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

Decisions on the TPM

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

2.17 In order to assist the Authority to make decisions about the TPM consistent with its statutory objective the Authority developed a decision-making and economic framework[3]. The Authority applied this framework to derive the proposal for the TPM that is set out in the October issues paper[4]. After considering submissions on the October issues paper and the responses of parties to the Authority's questions at the May 2013 TPM conference, the Authority has decided to develop and release a second issues paper. This will include a revised TPM

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3 Available from http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/.

4 Available from http://www.ea.govt.nz/our-work/consultations/priority-projects/tpm-issues-oct12/.

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

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

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

2.20 The Authority's Consultation Charter[5] sets out guidelines relating to the processes for amending the Code and the Code amendment principles that the Authority must adhere to when considering Code amendments.

[5] Available from http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/.

3 Submissions on this working paper

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

3.2 The Authority's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Authority, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with *Working Paper – Transmission pricing methodology: Avoided cost of transmission payments for distributed generation* in the subject line.

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

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

3.4 Submissions should be received by **5pm on Friday 31 January 2014**. Please note that late submissions are unlikely to be considered.

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

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

4 Background to policy and pricing principles

4.1 In 2003 the then Ministry of Economic Development (MED) released a discussion paper *Facilitating Distributed Generation.* The paper summarised the potential benefits of DG as being:

- improved economic and social outcomes through lower prices, and enhanced supply security
- better environmental outcomes through increasing renewable energy supply, and contributing towards reducing greenhouse gas emissions.[6]

4.2 The same MED discussion paper identified the benefits of DG more specifically as:[7]

- reducing peak demand for a lines network, enabling reduced transmission network charges
- assisting lines network companies with load management and reducing the need for lines network upgrades
- improving utilisation of the lines network with a two way flow of electricity
- reducing the need for Transpower to upgrade the transmission network as load growth is being accommodated external to the transmission network
- reducing transmission losses
- community benefits e.g. increased supply should put downward pressure on local electricity retail prices.

4.3 These benefits were also highlighted by some parties during the Electricity Authority's Transmission Pricing Methodology Conference in May 2013.[8]

4.4 Furthermore, the MED discussion paper noted the Government's overall objective for the electricity industry was to ensure electricity was delivered in an efficient, fair, reliable and environmentally sustainable manner to all classes of consumer.[9] The discussion paper pointed out that regulation of the interconnection of DG to lines networks was clearly provided for in a Government Policy Statement issued in December 2000 to "ensure the use of new electricity technologies and renewables, and distributed generation, is facilitated and that generators using these approaches do not face barriers".

4.5 The regulatory framework of the previous Government has now been replaced by section 15 of the Electricity Industry Act 2010, being "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers".

4.6 In the context of the Electricity Commission's objective and the requirements of the Electricity Act 1992 which applied at the time of the MED discussion paper,

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6 Facilitating Distributed Generation Discussion Paper 2003 p.2, paragraph 11.

7 *Ibid*., Table 1 p.15.

8 See http://www.ea.govt.nz/dmsdocument/15087, pp.292 to 335 of the transcript.

9 Facilitating Distributed Generation Discussion Paper 2003, p10. paragraph 49.

the discussion paper drew on the following underlying policy principles for regulating the connection of DG:

- potential investors need certainty about obtaining interconnection agreements and clear rules about interconnection charges and fees
- there should be full information available on the terms and costs of connection and transporting electricity from potential new generation in a lines network, to allow investors to make decisions
- to encourage investment, transaction costs to obtain interconnection should be reasonable
- the compliance costs of regulation should be minimised
- safe interconnection practices should be promoted, but safety issues should not be used as a barrier to interconnection
- flexibility needs to be retained to respond to individual generator and lines network needs
- local solutions to local energy needs, innovation and responsiveness to consumer demands should be encouraged
- competition in the generation and supply of electricity should be promoted
- there should be an investment environment that encourages small scale generation and the adoption of new electricity technologies and renewables
- there should be an investment environment that encourages the contribution of small scale generation to the delivery of electricity in an environmentally sustainable manner and to the overall security of the electricity system.

4.7 The proposed objectives and benefits of DG outlined in the 2003 discussion paper were the subject of extensive consultation with participants and consumers in 2006 and 2007. This lead to the development of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 which became effective on 30 August 2007. Those regulations were revoked on 1 November 2010 by the Electricity Industry Act 2010 and were replaced by Part 6 of the Code, which included the Schedule 6.4 pricing principles.

4.8 The Schedule 6.4 pricing principles require that:

- connection charges to DG must not exceed the incremental costs of providing connection services to the DG[10]
- the incremental cost is net of transmission and distribution costs that an efficient market operation service provider[11] would be able to avoid as a

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[10] Clause 2(a) of Schedule 6.4 to the Code.

[11] The Authority notes that the reference in clause 2(a) to an efficient “market operation service provider” is likely to be in error. Part 1 of the Code states that “market operation service provider” has the meaning given in section 5 of the Act which is “the system operator and any person appointed by the Authority under the Code to perform … market operation service provider roles”, which include the registry manager, reconciliation manager, pricing manager, clearing manager, market administrator, wholesale information trading system provider and any other role identified in regulations as a market operation service provider role. Section 7 of the Act specifies that distributors are “industry participants” rather than market operation service providers. The Authority's view is that the reference to 'market operation service providers' should be read as 'distributor'

result of the connection of the DG[12]. If incremental costs are negative, the DG is deemed to be providing network support services to the distributor, and may invoice the distributor for this service[13]

- costs that cannot be calculated (for example, avoidable costs) must be estimated. The estimate must be made 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.[14]

4.9 In summary, DGs that cause a net incremental cost to the distributor must pay the distributor, but if the incremental costs are negative (that is, the DG reduces the costs to the distributor), the distributor must pay the DG for the 'network support services' provided by the DG to the distributor.[15]

based on the context, and the heading to the pricing principle. Headings to provisions can be used to assist with statutory interpretation (see section 5 of the Interpretation Act).

[12] Clause 2(a) of Schedule 6.4 to the Code.

[13] Clause 2(e) of Schedule 6.4 of the Code.

[14] Clause 2(c) of Schedule 6.4 to the Code.

[15] Clause 2(e) of Schedule 6.4 to the Code.

5 The Authority's approach and method of the analysis

5.1 The Authority's approach was to examine distributors' ACOT payment policies, Transpower's treatment of DG, and investigate the influence that DG investments have on Transpower's investment decisions.

5.2 The ACOT payment policies of each of the 29 distributors have been reviewed, including the basis for the payments and the level of payments. While details of ACOT payments, the calculations and the sites they apply to tend to be confidential to the parties involved, the pricing methodology of each distributor is disclosed and published. Information has been extracted from the distributor policies and payments to DG from two main sources:

- the Commerce Commission's electricity disclosure summary database
- the 29 individual distributor websites, including the published pricing methodologies.

5.3 The Authority identified the prevalence of DG within each local network from the Authority's published dataset, which identified the location of each generator and ascertained if a generator was DG or grid connected.

5.4 Matching the locally connected generation to the payment information then provided some guidance for estimating the de-rating[16] of various types of generation, and the linkage between the payments and the avoided transmission charges.

5.5 After investigating distributors' ACOT arrangements, the second phase of analysis involved examining whether ACOT reduces transmission investment and transmission costs. In particular, the Authority:

(a) reviewed Transpower's and distributors' price-quality regulation arrangements to determine whether consumers benefit from ACOT and to assess how quickly any benefits of DG filter into reduced transmission charges

(b) reviewed the extent that DG shifts charges from one distributor to another

(c) reviewed the locational incentives provided by ACOT to ascertain whether ACOT promotes efficient location of DG. The Authority examined DG commissioned over the last ten years to determine the extent that DGs were located in electricity import constrained regions

(d) reviewed Transpower's planning process to determine the impact of ACOT on Transpower's investment decisions. The Authority reviewed a series of documents including a selection of Transpower's Asset Management Plans[17], the 2008 Statement of Opportunities, and the documentation available for grid support contracts.

16 The typical calculation for the reliable capacity contribution of a generation station is a function of its operating characteristics. For example, a 10 MW wind farm might reliably provide 3 MW of support.

17 Including Transpower's Asset Management Plans for 2002, 2007, 2008 and 2013. The years were spread out over a long time period to ensure that changes to investment decision-making processes could be effectively tracked.

5.6 As noted in paragraph 4.8, the pricing principles in Schedule 6.4 of the Code refer to incremental costs of providing connection services to the DG, net of any distribution and transmission costs avoided by the distributor as a result of connecting the DG. The Authority assessed whether, and to what extent, ACOT payments reduce or increase capital or operating costs of distributors.

5.7 The Authority also investigated whether ACOT payments based on avoided RCPD charges may result in perverse investment incentives. This involved considering:

(a) where distributors own their own DGs

(b) where ACOT payments are made to very old generation plant.

5.8 Finally, the Authority assessed the non-transmission/distribution benefits and costs of DG. This paper provides preliminary conclusions about the existence of benefits and costs and the extent that benefits are efficiently compensated for (and the extent that costs are efficiently imposed), either through ACOT payments or through existing market mechanisms.

5.9 The Authority considers that it is logical to split DG into two categories: larger DGs and very small scale or household DGs.[18] The two categories allow for separate consideration of the treatment of ACOT payments for each category. The rest of this paper refers to very small scale or household distributed generators as ‘small scale DG’ (SSDG) and larger distributed generators (or distributed generation) simply as ‘DG’.

18 For example, solar panels

6 ACOT policies of distributors

6.1 The Authority's analysis of ACOT payments indicates distributors in total are making payments in the vicinity of $50 million per year covering 766 MW. At a 10% discount rate, the present value of these payments is about $650,000/MW or $65,000/MW per annum. These payments amount to a substantial portion of the capital costs of the DG. The level of ACOT payments by distributors, as disclosed in publicly available material, is presented in Table 4 in Appendix A.

6.2 Notionally, adopting a capacity factor of 65%[19], 766 MW of generation equates to approximately 500 MW of "avoided" transmission. This figure is notional because if the transmission capacity already exists or if there is significant excess transmission capacity then the cost has not been avoided.

Distributors' treatment of ACOT payments

6.3 Transpower recovers its interconnection costs from each customer on the basis of each customer's share of Regional Coincident Peak Demand (RCPD) across four regions[20]. Customers in the upper North Island (UNI) and upper South Island (USI) regions are charged on the basis of the top 10 peaks at their respective interconnection points while customers in the lower North Island (LNI) and lower South Island (LSI) regions are charged on the basis of the top 100 peaks.

6.4 As noted in paragraph 4.8, the ACOT payments from distributors to DGs are provided for under Schedule 6.4 of the Code, and must take into account the transmission or distribution costs that a distributor "would have been able to avoid as a result of the connection of the distributed generation".[21]

6.5 The Authority investigated the ACOT payment policies of the 29 distributors, which are summarised in Table 1 below. Table 1 shows that 18 distributors appear to base their ACOT payments on a pass-through of Transpower's interconnection charge. That is, 18 distributors pay ACOT to each DG on the basis of the transmission charge that was avoided on account of that particular DG's generation during RCPD.

Table 1: Types of ACOT payment policies

Type of payment	Number of distributors	Benefit to consumers
Based on Transpower interconnection (RCPD) charge	18	Transmission benefits, if any, are obtained by consumers via lower RCPD (interconnection)charges over the long run
None or not applicable	6	Unclear
Other basis for payment	5	Potentially lower transmission and distribution charges for consumers

19 This estimate is based on Authority analysis of ACOT payment information from the Commerce Commission's electricity disclosure summary database, information published by distributors' published pricing methodologies, and the Authority's published dataset on DG.

20 Upper North Island (UNI), Upper South Island (USI), Lower North Island (LNI), Lower South Island (LSI)

21 Clause 2(a), Schedule 6.4 of the Code

6.6 The following wording is typical of many of the pricing methodologies adopted by distributors across the country in relation to DG[22]:

> *Monthly avoided transmission payments are paid at the Transpower interconnection rate, $99.44/kW for the 2013-14 pricing year. The methodology used in determining these payments is based on Transpower's interconnection pricing methodology. That is, generators are paid based on their generation during the 100 peak Lower North Island (LNI) demand periods. These payments to the generator are equal to the additional interconnection charges that Unison would otherwise have paid to Transpower if the generation had not occurred. The value of these payments varies year on year dependent on the individual generators level of generation during the 100 LNI demand periods.*

6.7 Key to determining the ACOT payment to DG is the phrase "would otherwise have paid to Transpower if the generation had not occurred." That is, an amount equal to the avoided transmission charge is paid to the DG.

6.8 Five distributors have ACOT payments that are not linked directly to the Transpower interconnection rate and calculation method.[23] Of these, two reference methods other than a simple peak reduction such as distribution network savings, and two identify that there are limits to charges or the benefits considered in determining charges. One states that their objective is to avoid subsidising generation.

6.9 Six distributors currently do not make ACOT payments or ACOT payments do not feature in their pricing.

6.10 The Authority also examined a selection of distributor Asset Management Plans to determine the approach to payment of ACOT for SSDG. This suggests ACOT payments are not paid to SSDGs because SSDGs cause costs to distributors. Powerco, for example, stated that 'the initial impacts of SSDGs on networks are actually creating constraints and needs".[24]

6.11 A brief summary of the different approaches of the distributors to ACOT payments is provided in Table 5 of Appendix B.

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22 Unison Pricing Methodology Disclosure 2013, p. 53.

23 For example, Orion calculates a network long run average incremental cost (LRAIC) to recompense for value to Orion from DG in addition to paying a RCPD Transpower avoided charge component.

24 Powerco Asset Management Plan, p. 156.

7 Do ACOT payments reduce transmission costs?

Do consumers benefit from ACOT through reduced transmission charges?

7.1 Referring to Table 1 above, it appears that 18 of the 29 distributors pay 100% of the avoided Transpower interconnection charge to the DG. Under the Default Price Path regulation that applies to non-exempt distributors[25], the distributor is able to recover a charge payable to Transpower under the TPM, and any amount calculated in accordance with Schedule 6.4.[26] That is, consumers pay the transmission charge, reduced to the extent DG lowers the charge, plus qualifying ACOT payments.

7.2 In effect, if a distributor pays DGs its avoided transmission charges and passes on 100% of the "avoided" transmission charge to DGs, connected consumers receive no reduction in transmission charges. This is the case even if ACOT reduces Transpower's investment requirements.

7.3 The pricing disclosures confirm that the ACOT payments are directly funded by consumers – as noted above, such payments are recoverable costs under the regulated revenue process. This type of arrangement suggests that there is little incentive on distributors to heavily scrutinise the calculation of ACOT payments as there is potentially a higher cost in performing a more accurate assessment, and no particular benefit to the distributors as the ACOT payments are a recoverable cost.[27]

7.4 The pass-through of the avoided Transpower interconnection charge appears to be a straightforward and low cost approach adopted by distributors. A more complex approach may result in higher administrative costs for distributors but provide no additional benefit to them.

Are reduced transmission costs resulting from DG, if any, reflected in Transpower's maximum allowable return?

7.5 Transpower's interconnection charge is calculated under the TPM based on Transpower's maximum allowable revenue (MAR). The level of the interconnection charge varies from year to year, with the rate ($/kW) set by the total revenue required and by the overall regional coincident peak demand (RCPD). The fact that Transpower is subject to a revenue cap rather than a price cap means that the rate of the interconnection charge varies depending on total regional coincident peak demand.

7.6 To illustrate this, suppose the regulated sum to be recovered is $500 million per annum for 5,000 MW of electricity demand ($100,000/MW or $100/kW). If demand is reduced by the presence of DG, the interconnection charge rate would increase to ensure $500m is recovered. For example, a demand reduction of 500 MW (from 5,000 MW to 4,500 MW) would result in the interconnection charge

25 Under Part 4 of the Commerce Act 1986, distributors are subject to default/customised price-quality regulation. However, distributors that meet the 'consumer-owned' criteria set out in s 54D of the Act can qualify for exemption from this type of regulation.

26 See the definition of "recoverable costs" in paragraph 3.1.3 of the Electricity Distribution Input Methodologies 2012.

27 *Ibid.*

increasing to $111/kW ($500 million / 4,500 MW) to ensure Transpower recovered its MAR.

7.7 Therefore, in the short term, since Transpower’s revenue means the costs recovered from transmission charges does not change, there is no immediate reduction in transmission charges as a result of any new DG in the short term, and therefore no offsetting reduction in transmission charges for consumers.

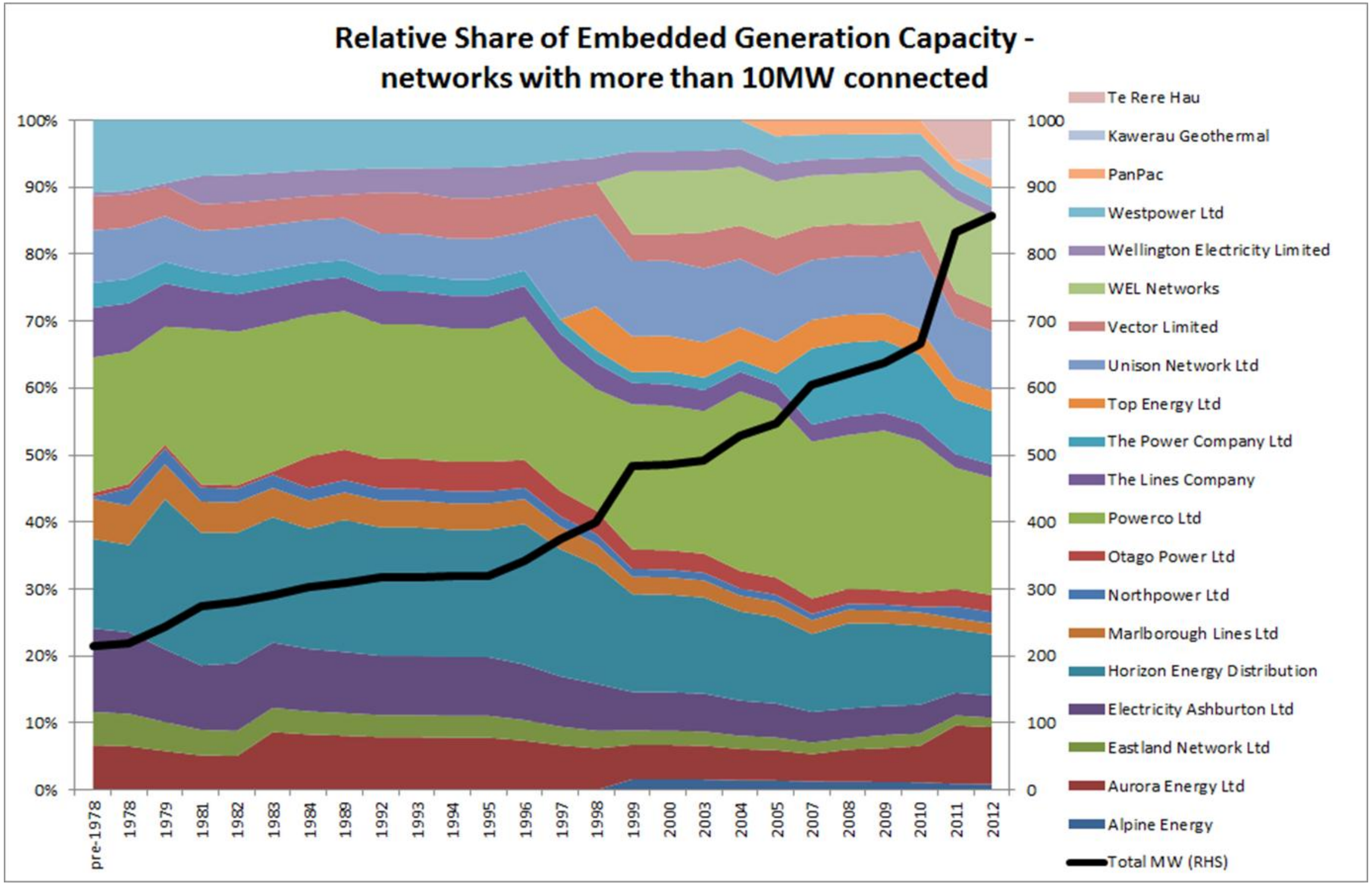
7.8 In the longer term, DG could influence Transpower’s revenue cap and therefore, the quantum of transmission charges. If DG causes or contributes to a delay or cancellation of capacity enhancing capital expenditure AND this results in the regulated asset base being less than it otherwise would have been without the DG, the DG would have promoted savings in transmission costs. However where ACOT payments pass those avoided transmission charges to the DG, consumers will not see this saving.

Effect of ACOT payments between distributors

7.9 Under Transpower’s revenue cap described above and the method used for calculating interconnection charges, the presence of DG has the potential to shift interconnection charges from one distributor to another. Savings in the Transpower charges payable by an individual distributor are possible if the proportion of DG in that distributor's network increases more rapidly than the growth rate of DG across all distributors on average. The general case, however, is that the reduction in interconnection charge is likely to be lower than the ACOT payment resulting in a higher overall charge to consumers. This is because Transpower’s total revenue to be recovered through the interconnection charge remains the same in the short term (recovered on a smaller RCPD value), but the ACOT payment is paid on a larger installed distributed generation base.

7.10 The following chart (Figure 1) illustrates the changing relativity across the past 25 years for those networks with more than 10 MW of DG. For most distributors their relative share of the DG market has remained static while the size of the DG market has doubled.

Figure 1 Relative share of distributed generation market last 25 years



7.11 Figure 1 shows that, apart from a few exceptions, even with additional DG being connected, the relative percentage share of DG does not change materially for a majority of the distributors shown. This means most distributors' share of Transpower interconnection charges as a result of DG is not likely to change much.

7.12 It should be noted that direct connect customers are also required to pay interconnection charges. This means if DG causes costs to rise, direct connect customers, particularly those without DG, or those with a falling proportion of DG, are likely to bear a greater proportion of transmission charges than otherwise. In this context, the interconnection rate has increased from $63.74/kW in 2008/09 to $90.66/kW in 2012/13 to just under $100/kW for 2013/14.

7.13 Between 2000 and 2010, DG capacity increased from 485 MW to 666 MW (an increase of 181 MW). For a distributor with no changes within their network, the proportion of the DG market on their network would have fallen by around 27% (for example, Northpower dropped from 1.13% to 0.83%). Distributors with increases in their connected DG capacity have seen increases in share of total connected DG of around 10% (for example, Powerco increased from 20.89% to 22.17%).

7.14 For context, however, these changes need to be considered with respect to the total RCPD of 6,032 MW for the 2012/13 year.[28] The additional 181 MW of DG over ten years represents just 3% of the RCPD, assuming the generation makes a 100% contribution to reductions in RCPD. However, using the average de-rating of capacity[29] of 65% (based on the schedule of payments) the impact is closer to 2%.[30]

7.15 In terms of the interconnection rate, the 2012/13 rate of $90.66/kW would have been $88.93/kW (as RCPD would be 65% * 181 MW higher at 6,150 MW recovering the same dollar value). Thus, a distributor with no changes to its DG capacity, or a direct connect customer without DG, would see a higher annual interconnection charge due to the installation of DG capacity in other networks. This is a side-effect of the existing TPM.

7.16 In conclusion, the presence of DG is likely to have the effect of shifting interconnection charges to other distributors and direct connect customers that have little DG. Therefore the transmission charges faced in areas with no DG may be higher than would otherwise occur. That is not a result of the ACOT payment itself, but rather the method for calculating transmission charges.

Locational incentives

7.17 Whether promotion of DG through payment of ACOT provides economic benefits derived from transmission largely depends on whether the transmission network is constrained or approaching constraint and whether DG can help to relieve the constraint.

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28 Note, the RCPD in 2008/09 was 6,052 MW and was below 6,000 MW until 2012/13.

29 "De-rating" refers to the typical calculation for the reliable capacity contribution of a generation station, which is a function of its operating characteristics. For example, a 10 MW wind farm might reliably provide 3 MW of support.

30 181/6032 = 3% * 65% = 2%.

7.18 This section considers whether ACOT payment policies influence incentives for DG to locate within one local network over another.

7.19 The list of generation shown in Table 2 below shows the DG type for 155 projects. It is a subset of the full list of 217 projects published by the Electricity Authority.[31]

Table 2: DG stations – classification

Generation type	Number of Installations	Connected Capacity (MW)
Back up Generation	9	1.9 MW
Cogeneration	11	128.8 MW
Geothermal	6	120.7 MW
Hydro	62	223.9 MW
Biogas	10	31.2 MW
Thermal	21	40.9 MW
Wind	14	295.8 MW
Unknown	22	9.7 MW
Small (under 1 MW)	73	17.5 MW
Medium (1 MW to 5 MW)	42	112.0 MW
Large (over 5 MW)	40	723.4 MW
Total	**155**	**852.9 MW**

7.20 The geothermal and biogas plants would be expected to provide a reasonably secure, base-load level of generation with 150 MW of installed capacity. However the location for these projects is resource dependent, with geothermal being either at Ngawha or the central North Island/Bay of Plenty regions.

7.21 Hydro generation is also resource dependent, requiring specific geographic features to enable development (a river).

7.22 Wind generation is potentially the least location dependent with large areas for the country possessing viable wind resources. However, these projects still tend to rely on suitable resources (higher wind speed and land access), and consents for the activity.

7.23 Thermal plants (which are usually diesel) and back-up generators are not particularly resource dependent. This totals 30 of the 155 plants. These plants are generally not designed to provide low cost supply.

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31 The list can be found at http://www.ea.govt.nz/industry/monitoring/forecasting/long-term-generation-development/list-of-generation-projects/.

7.24 A further 22 projects listed as “unknown” mostly have a very small nominated capacity, often recorded as zero and thus are not likely to assist generally with meeting demand.

7.25 In conclusion, the location choice of many DGs is predominantly based on the location of the energy source.

7.26 To further assess locational incentives for DG, the Authority has investigated whether DGs commissioned within the last decade[32] have been located within import-constrained regions.

7.27 For the purposes of the analysis, import constrained regions are regions which would be served by one or more of the reliability investments[33] that have been approved by the Electricity Commission or Commerce Commission.

7.28 Figure 2 below provides the results of the analysis. This indicates that, in recent years, the majority (in capacity terms) of new embedded generation over 1 MW was not located in areas where it could have helped to defer or reduce the need for high-voltage transmission investment in the short to medium term.

7.29 The main exceptions were:

(a) the White Hill and Mt Stuart wind farms, located in Southland. These are located such that they could defer the need for elements of the LSI Reliability investment, although it is not clear that they actually did so

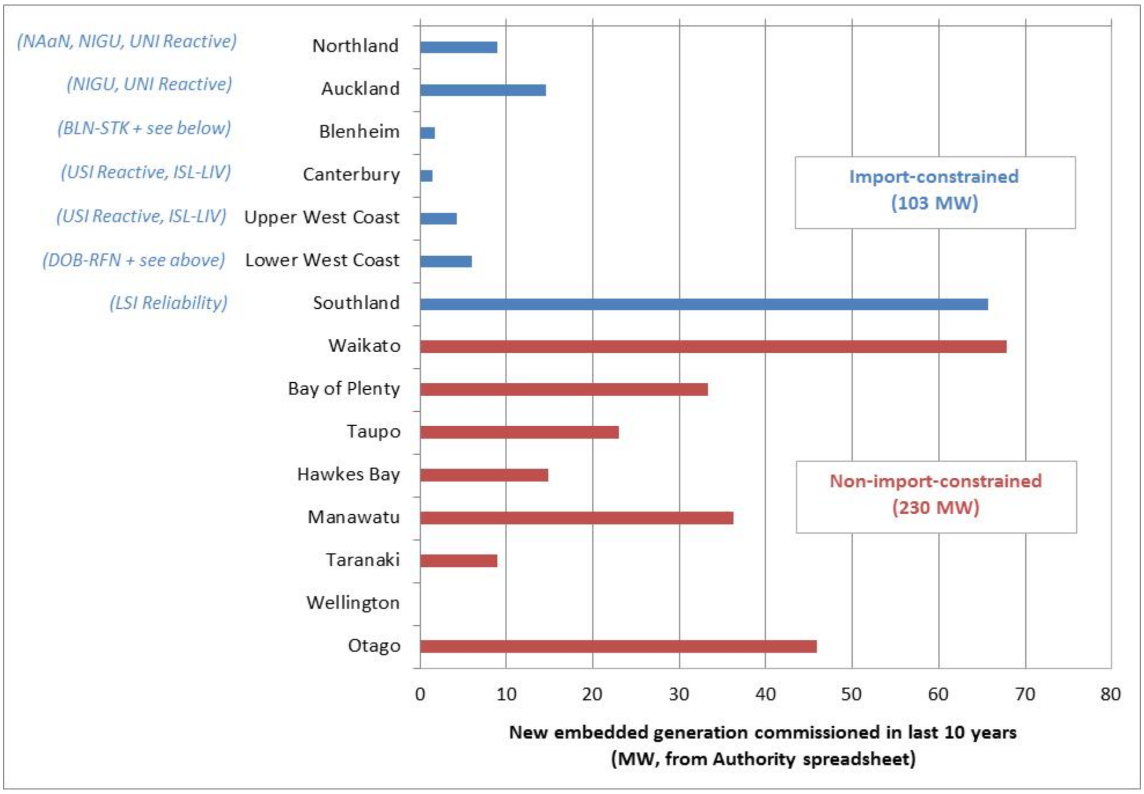
(b) the Marsden Diesel peaker, located in Northland, an import-constrained region with little local generation. This could potentially help to defer the need for future real and reactive power investments in the upper North Island

(c) the Amethyst and Rochfort Hydros, located on the West Coast of the South Island, a region that is sometimes import-constrained. This could potentially help to defer the need for future real and reactive power investments into and within the region.

[32] Where operating capacity and location are known

[33] For this purpose, the Authority has focused on upgrades increasing capacity, rather than like-for-like replacements. These include: North Auckland and Northland (NAaN), North Island Grid Upgrade (NIGU), Upper North Island Dynamic Reactive (UNI Reactive), Blenheim-Stoke (BLN-STK), Upper South Island Reactive (USI Reactive), Islington-Livingstone (ISL-LIV), Dobson-Reefton (DOB-RFN), and LSI Reliability.

Figure 2:Location of distributed generation in import-constrained and non-import constrained regions over the last ten years



Source: Electricity Authority

7.30 The Authority has considered the incentive to locate DG in one area over another. Proximity to load or a reduction in transmission constraints does not appear to have been influential factors in selection of the location of DG since 2007 when ACOT payments were introduced. There does not therefore appear to be strong evidence that DG location has been determined by avoidance of a transmission investment. Access to a suitable site or resource appears to have been more important.

8 Do ACOT payments reduce transmission investment?

8.1 This section investigates whether ACOT payments made by distributors to DG have an impact on transmission investment decisions. To do this the Authority has investigated the following matters:

- the extent to which DG is included in the demand forecasting used in transmission capacity planning
- whether the presence of DG has been taken into account in the transmission asset management plan
- whether reductions in demand caused by ACOT payments may result in lower transmission costs and therefore lower charges in the longer term.

Demand forecasting

8.2 Transpower conducts demand forecasting[34] as part of its grid planning process.

8.3 DG can affect the demand forecast in two ways:

- known future DG developments can be explicitly considered in the demand forecast
- growth in DG over time has the effect of reducing demand growth served by the national grid.

8.4 Most DG projects are simply too small to be included explicitly in the demand forecast. This, coupled with a high degree of uncertainty regarding future DG projects, and the low contribution of intermittent DG to meeting peak demand, means the effect of explicitly modelled DG schemes on peak demand forecasts is generally minor.

8.5 Smaller schemes can affect the forecast implicitly, by slowing demand growth. However, the amount of DG that is too small to be modelled explicitly in the demand forecast, yet large enough to receive ACOT payments, is quite limited at this point.

8.6 The implication is that ACOT-funded DG appears to have quite limited impact on Transpower's peak demand forecasts, and hence limited ability to defer the assessed need for transmission investment.

8.7 DG can actually bring forward the assessed need for transmission investment. Transpower's forecasts include an assessment of the additional transmission investment and costs caused by DG.[35] This includes:

- forecasting of demand troughs caused by excess generation in particular areas
- capturing net injection onto the Transpower grid from distributed generation.

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34 Note that the demand forecasting referred to here is electricity demand served by the transmission grid, which differs from electricity demand by consumers.

35 Transpower 2013, *Annual Planning Report*, March 2013.

Asset management planning

8.8 In order to investigate the premise that DG may avoid transmission investment the Authority has reviewed the Annual Planning Reports and Asset Management Reports (AMPs) produced by Transpower. In particular, a series of reports from 2001/02, 2007, 2008 and 2013 were reviewed. Using multiple AMPs has the advantage of a detailed analysis of the grid and the planning process, and provides a longitudinal view across a 12 year period. For this 12 year period the Authority examined the DG projects that have been planned, commissioned or abandoned and cross-referenced this treatment against the grid planning process.

8.9 Between 2001 and 2013 there were 28 DG projects listed in Transpower's planning reports with a total capacity of around 373 MW. These projects, and others, are provided in Appendix C. A large proportion of this capacity (243 MW or 65%) came from five wind projects (Tararua, White Hill, Mahinerangi, Te Rere Hau and Te Uku) and a further 48 MW (13%) from two geothermal stations. The only other plant above 10 MW was a wood waste co-generation plant leaving 70 MW distributed across the remaining 20 projects. The majority of these plants were anticipated to be embedded within local networks.

8.10 The review process examined the grid back-bone development plus each of the regional plans. Due to the small size of the generation projects that were to be connected (including the 20 projects totalling 70 MW) this review assumed that the detailed regional forecasts provided by Transpower would more easily identify any changes in demand or allowances for DG.

8.11 To illustrate the process, consider the possible grid configuration for the central North Island from the 2013 Transpower Annual Planning Report. This is shown in Figure 3 below. This provides a useful illustration as it contains significant existing DG, proposed future DG projects, and grid-connected generation.

8.12 Commentary from the 2013 Transpower Annual Planning Report highlighted that:

- additional generation in the region may bring forward transmission investment rather than defer or reduce investment[36]
- generation is provided at twenty different locations and forecasts are shown for the years 2013 to 2028, including DG. The only forecast change is for a decrease in capacity at Wairakei[37]
- none of the eighteen off-take points[38] demonstrated a reduction in demand (which could be an indication of DG)
- transmission issues are dominated by security of supply issues (which distributed generation does not appear to assist with)
- Transpower anticipates additional generation might be connected within the region, including wind developments near Linton. It states that up to 830 MW "will not cause system issues" for the 220 kV transmission

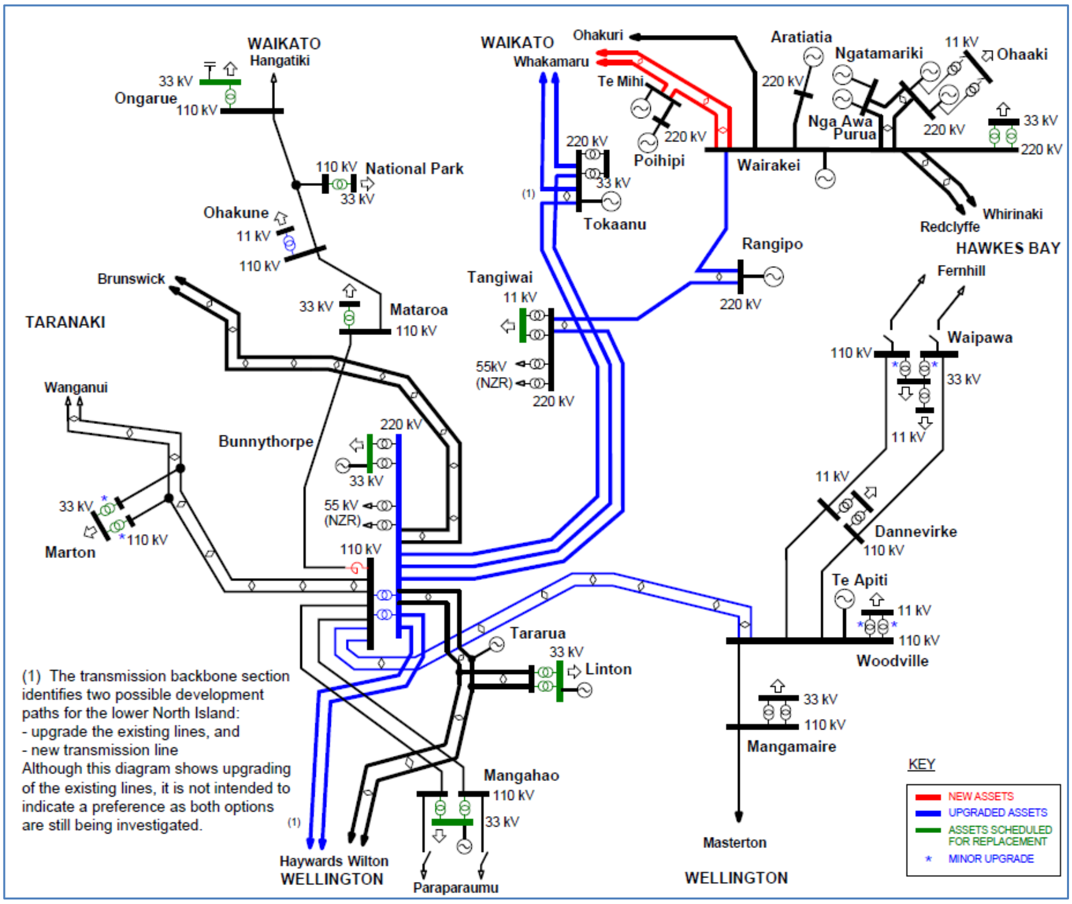
[36] Transpower 2013, 11.2.3.

[37] Transpower 2013, table 11.2.

[38] As listed in Transpower 2013, table 11.1.

network. The report indicates that on the 110 kV network, more than 80 MW of generation may require additional transmission investment.

Figure 3:Possible central North Island transmission 2028



Source: Transpower 2013, Annual Planning Report, p.182.

8.13 The above example appears typical of the issues being considered at the grid planning level. Naturally, other regions have different issues. Examples include:

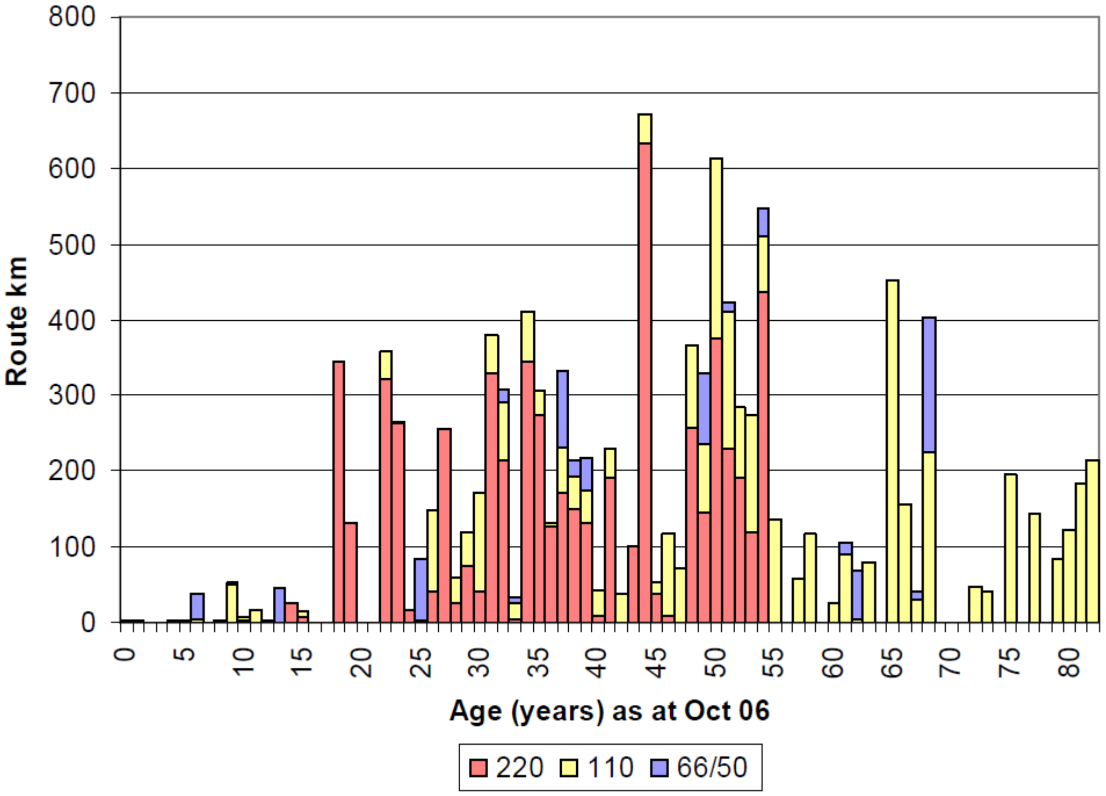
- the Waikato is a net exporter of electricity (the location of a recent distributed wind farm)
- additional DG can reduce demand in one area and introduce over-loading on other parts of the grid (too much generation at Hangatiki contributes to overloading of Arapuni to Hamilton circuits)
- the Bay of Plenty faces transmission constraints due to excess local grid-connected generation and DG. There is a suggestion that generation would need to be turned off to prevent overloading (a prospective project near Okere is specifically mentioned)
- n-1 security can be compromised due to generation outages (a Ngawha outage may cause the Kaikohe to Maungatapere circuits to exceed n-1 capacity)

- there are limits on connecting generation at different locations, but these limits can be high (for instance, an additional 300 MW at Maungatapere or Kaikohe would be possible).

8.14 Another theme that emerges from the planning reports is that the transmission capacity is typically installed in hundreds of megawatts. Allowances for new generation anticipate few problems until generation reaches quite high levels (see the 830 MW reference above in paragraph 8.12, or the reference above to an additional 300 MW of generation in the Kaikohe area).

8.15 The bulk of new DGs that have been installed were small fractions of the transmission capacity and often comparable to the rate of local annual demand growth. Therefore, where there is available transmission capacity, the installation of small scale DG is likely to have a minimal impact on transmission investment decisions.

Figure 4: Transpower transmission line age profile



Source: Transpower, Asset Management Plan, September 2009, p. 33.

8.16 Minor changes to installed line capacity are further discouraged by the lumpiness of transmission investment. Figure 4 above, which is a chart from the 2007 Transpower planning report, illustrates that the investment decision for the bulk of the transmission system is largely historic and was made between 30 and 60 years ago.

8.17 The long life of the assets and the relatively limited number of investments within the past 20 years indicates that the placement and commissioning of DG is unlikely to have substantially altered the progression of transmission investment. Note, however, that some of the more recent transmission investment has been used to connect generation projects to the Transpower network (such as West Wind).

Transmission pricing and Grid Support Contracts (GSC)

8.18 Under the Schedule 6.4, distributors must pay a DG if the incremental cost to the distributor of connecting the DG is negative.

8.19 The requirements placed on distributors could be viewed as an alternative to a direct arrangement between Transpower (who would be making the decisions about investment and transmission alternatives) and the generator. In some cases, generation may offer an alternative to augmentation of transmission. The following paragraphs consider the extent to which it would be feasible for generation to act as a substitute for transmission services.

8.20 The use of generation as an alternative to transmission is addressed in Transpower's documentation on grid support contracts (GSCs). GSCs assist Transpower to manage risks resulting from any construction delays, higher than forecast demand growth or major asset failure, and to defer some transmission investment under certain conditions. The scope of the standard contract includes consideration of all forms of non-transmission options, including large and small generation and both aggregated and distributed demand side participation.

8.21 Perusal of GSC documentation has provided relevant insights that are described in the following two sections. The power system is generally run at an n-1 level but only against the more likely operational contingencies. In meeting the requirements of reliable supply and the n-1 security standard, Transpower appears to consider generation may not provide an adequate substitute (although the success of the recent demand response trial[39] has the potential to alter Transpower's position somewhat in the future).

8.22 In particular, Transpower commented that:[40]

> *It is unrealistic to expect local generation or demand response to be able to achieve levels of reliability usually expected of the transmission system. However, a reliability level of around 99% to 99.9% may be achievable and may be adequate provided exposure to such levels is limited to system peaks and short periods. This lower reliability could be justified by the value of GSCs as a risk management tool. In Transpower's view, reliability levels less than 99%, or prolonged exposure to low reliability levels, would not be acceptable for the backbone interconnected grid.*

8.23 As a contract to meet specific and defined performance requirements, a critical design of GSCs is to be able to perform as and when required. A failure in a generation plant may have serious consequences including non-supply and

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39 For further information on Transpower's demand response programme see: https://www.transpower.co.nz/projects/demand-response-project/demand-response-programme. Although this programme is testing whether demand response can be used as a non-transmission solution, Transpower note that the ability to participate could involve use of a standby generator. Refer: Transpower, Frequently Asked Questions Demand Side Initiative Programme, page 1, available at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/DemandResponseFAQ.pdf.

40 Transpower 2010, *Design Features for Grid Support Contracts*, July 2010, p.viii.

unexpected market outcomes. Feedback from a 2008 GSC trial indicated that submitters:[41]

(a) did not view GSCs as substitutes for transmission investment in the long term, but did consider that GSCs may be appropriate for short-term risk management as needs arose

(b) raised significant concerns over the concept of GSCs being used to defer transmission investment

(c) raised significant concerns over market generation GSCs, which could significantly distort the electricity market.

8.24 Furthermore, because of the requirements for performance at particular times, Transpower did not consider intermittent generators (including wind and small run-of-river hydro) as viable candidates for GSC. Thus intermittent generation would not likely be eligible for payments under a GSC.

8.25 If a generator is not eligible for payments under a GSC, it is not clear whether it could be established that the same generator realistically avoids transmission costs. Overall, it appears that DG is not considered by Transpower to be sufficiently reliable under the n-1 security standard to replace transmission assets with generation alternatives, although as noted above there is potential for Transpower’s position to change somewhat in the future as a result of initiatives like Transpower’s demand response programme.

8.26 While there was support for the introduction of GSC payments (albeit not for DG), Transpower and market participants recognised that a payment under a GSC could affect the market for electricity generation. Maintaining efficiency in that market (investment in capacity) and maintaining a competitive working spot market were viewed by these parties as “paramount”.

8.27 In summary, the types of comments included:[42]

- emphasis of the importance of avoiding interference in energy markets, and noted that GSCs for market generation would inevitably distort that market
- that a more appropriate means of achieving efficient generation investment, allowing for the costs of transmission, would be through amendment to the transmission pricing methodology (TPM).

8.28 To be a candidate for a GSC with Transpower, the project needs to be commercially viable in its own right and the project committed without additional supporting payments. It is also relevant to note that GSC payments are intended for a fixed term, possibly linked to when a particular transmission investment is no-longer deferred.

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41 Transpower 2010, *Design Features for Grid Support Contracts*, July 2010, p.18.

42 *Ibid*.

9 Do ACOT payments avoid distribution investment or costs?

9.1 Schedule 6.4 of the Code anticipates that where DGs provide benefits to a distributor, the distributor would make payments to the relevant DG accordingly through ACOT payments. In order to better understand whether DG currently provides economic benefits to distributors such as avoiding distribution network costs and reliability benefits, the Authority reviewed the Asset Management Plans (AMPs) of four distributors: Vector, Orion, Powerco, and Counties Power.

9.2 Orion "encourages investment in transmission and distribution alternatives (e.g. distributed generation or demand response)"[43] and has established payments to DGs "in lieu of distribution costs".[44] This suggests that Orion recognises that DGs do, at least in some circumstances, provide economic benefits to distributors. Orion's emphasis on providing credits for pre-approved reliable DGs connected to its network, based on the amount of electricity they provide during periods of high network loading, may be a reasonable proxy for avoided distribution network costs[45].

9.3 The Orion example establishes that it is commercially viable for diesel generation to be used to manage distribution network peaks. Orion's policies to reward firm generation that reduces peak load have influenced DG investors to prefer gas or diesel generation in place of intermittent generation such as wind or solar. This is an example of a policy for recognising benefits of DG to distributors, and compensating DG accordingly.[46]

9.4 Powerco's AMP stated:

> *In the long term it is hoped that distributed generation will either reduce peak demand growth and/or provide a means of managing demand peaks through additional localised capacity and security. Unfortunately, in the current environment and the early stages of deployment, quite the opposite is true. DG is currently focused on energy volume and has very limited availability for security purposes – and can't have without energy storage capability, which is either very rare or expensive…the initial impacts of small scale DG on networks are actually creating constraints and needs.*[47]

9.5 Powerco further explained that localised issues, caused in part by the presence of DG, have been manageable without major network reinforcement to date. However, Powerco consider that, should DG reach a higher density, major network infrastructure investment will be needed to stabilise distribution voltage levels.

9.6 It appears that Powerco is of the view that DG does not benefit distributors and in fact can create costs for distributors but that this may change in the future with better energy storage technology. However, Powerco's explanation of DG issues

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43 Orion AMP 2013, p. 36.

44 Orion AMP 2013, p. 6.

45 A guide to Orion's pricing 1 April 2010 to 31 March 2011.

46 The economic and system impacts of increased DG connection within New Zealand's electricity networks, New Zealand Centre for Advanced Engineering, November 2007, p. 51

47 Powerco AMP 2013, p. 156

does not entirely preclude the possibility of larger scale DG creating benefits for distributors.

9.7 A 2007 case study by the New Zealand Centre for Advanced Engineering[48] indicated that DG could be of assistance in remote areas, particularly in areas experiencing demand growth. The paper suggested that DG could potentially reduce demand and, hence, Transpower charges. The paper states that “DG development would be more advantageous in remote regions where it can increase supply security by providing an electricity source should parts of the network become isolated due to network failure”.

9.8 Counties Power’s AMP provided a different view:

> *Isolated generators, because of the nature of our distribution system and particularly in remote areas, are connected to radial feeders and hence, only have a security level of n…Hence from an area security aspect, the generation cannot be included in the maximum demand forecast used for n-1 security-level planning and development of supply to the area.*[49]

9.9 This suggests that Counties Power consider DGs do not benefit its network where DG is situated in isolated locations.

9.10 Vector’s AMP noted that:

> *where fault level constraints exist, this … limits Vector’s ability to accommodate distributed generation (unless significant network reinforcement is carried out).*[50]

9.11 Vector also noted that DG from photovoltaic (PV) generators “may impact on network security, as the effective load reduction would increase the backstop capability at zone substations”. Vector went on to note that PV is intermittent “and without further energy storage or other localised forms of generation, (PV) is not a reliable energy source”.[51]

9.12 Overall, evidence from the sample of recent AMPs of distributors suggests that DG can create benefits under a very particular set of circumstances but there are also likely to be costs, particularly without better energy storage, and that costs may increase as DG becomes more predominant.

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48 The economic and system impacts of increased DG connection within New Zealand’s electricity networks, the New Zealand Centre for advanced engineering, November 2007, p. 46

49 Counties Power AMP 2013, p. 104

50 Vector AMP 2013, p. 20

51 Vector AMP 2013, section 3, p. 7

10 Can ACOT payments result in inefficient subsidisation of DG?

10.1 The Authority has identified two particular situations where, in theory at least, ACOT payments could result in inefficient subsidies to DG:

(a) where distributors own DG

(b) where ACOT payments are made to older generation plant.

10.2 Inefficient subsidies might occur in these situations where ACOT payments to DGs make the DG more economically viable than other DG not receiving ACOT payments or grid-connected generators.

Risk of inefficient subsidies where distributors own DG

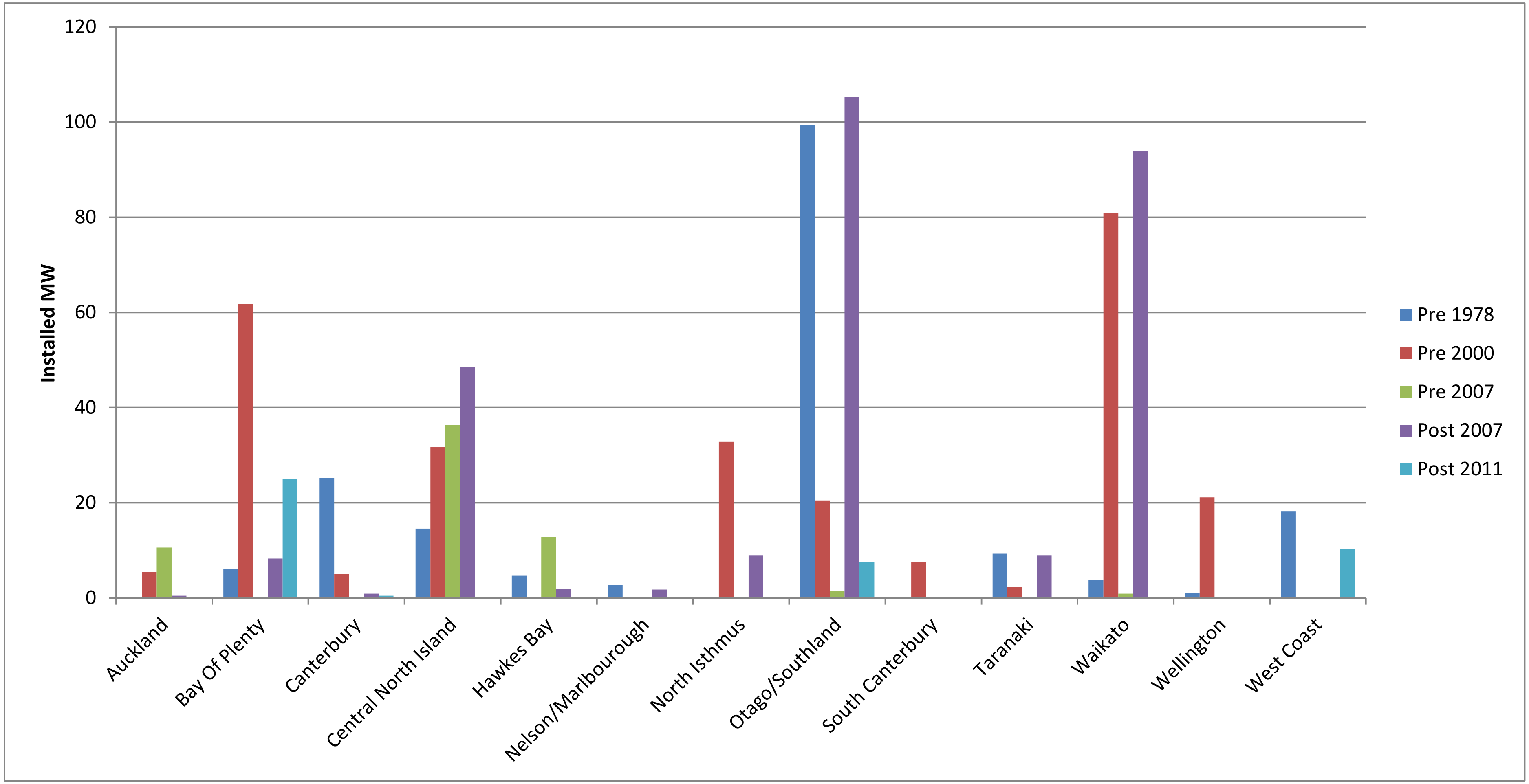
10.3 Some distributors own DG on their own networks and their DG receives ACOT payments. Given distributors are the parties that determine payment of ACOT, there is potential for preferential treatment, although the Authority has no evidence to suggest this has happened in practice. The risk here is that ACOT payments by a distributor to their own DG in preference to competing DG could result in lower cost projects being supplanted by less efficient or higher cost schemes. The risk of preferential treatment to distributor-owned does not, however, solely arise in relation to ACOT, as distributors also control connection to their networks.

Risk of inefficient subsidies from ACOT payments to older generation plant

10.4 ACOT payments are made to some generation plant that predates the introduction of ACOT by many years. Some of the oldest stations were constructed before the local area was connected to the national grid, and others would have been constructed to address supply shortages that occurred during the mid-20th century. Figure 5 below shows the age profile of distribution generation capacity by region.

Figure 5:Cumulative Regional Distributed Generation

Source: Electricity Authority



10.5 Some older plant was not built to avoid transmission and may have added to transmission costs. For example, Table 3 below lists a group of 13 stations totalling 145 MW which were prompted by the local hydro scheme included in the 1977 New Zealand Government Budget.[52]

Table 3: Distributed generation constructed under the 1977 Local Hydro Policy

Generation Sheme	Commissioning date	Capacity	Cost $ M (in dollars of the day)
Ruahihi	July 1981	20 MW	63.2
Aniwhenua	October 1980	25 MW	29.0
Wairere Falls	May 1981	3 MW	4.4
Wheao	July 1984	24.4 MW	45.6
Hinemoaia	November 1983	3.75 MW	5.9
Waihi	July 1985	3 MW	26.8
Patea	June 1984	30.7 MW	85.5
Branch	August 1983	11 MW	25.0
Duffers	July 1981	0.62 MW	0.7
Montalto	June 1982	1.7 MW	4.8
Turnbull	August 1981	0.6 MW	1.0
Paerau Gorge	June 1984	12.2 MW	34.3
Teviot	May 1981	9.1 MW	6.7

Source: Power to the People, Neil Rennie. Electricity Supply Association of New Zealand, 1989.

10.6 On the other hand, now that older DGs are established in their respective locations, their continued operation may be contributing to an alleviation of congestion on a local network. However, these generation projects do not appear to materially alleviate capacity restrictions on the Transpower grid. It is likely that at least some of these DGs receive ACOT payments but other grid connected stations that have similar established long-term location and production profiles do not receive ACOT payments. It is therefore questionable whether payment of ACOT to older DG provides net benefits.

10.7 A further issue may arise where Transpower sells grid assets to distributors or other parties and generators that were previously grid connected are reclassified as DGs and thereafter be eligible for ACOT payments. This raises the question of

[52] The scheme provided concessional finance to fund investigation and design work and to finance construction. Additional loans from the New Zealand Electricity Department were available to cover operating losses in the early years of approved schemes. The policy provided a subsidy for these projects and they do not appear to have been designed with the intention of reducing transmission or distribution investment.

[53] Facilitating Distributed Generation: a discussion paper, MED, September 2003, p. 7

whether it is efficient that re-classified generators are eligible for ACOT payments.

10.8 Given the historic nature of some of these plants it may be more efficient that no ACOT payments are made to DG that has long been part of the electricity system, or which were previously grid connected generators. The assessment process used to determine eligibility for ACOT payments could determine if it is efficient that a plant receive ACOT payments.

11 Other potential benefits and costs from DG that might merit ACOT payments

11.1 The DG provisions in the Code originated partly due to concerns that (usually smaller) DG operations had to negotiate with distributors with natural monopoly characteristics that had little competitive pressure to be responsive to the needs of DG.[53] At the time, DGs argued that distributors could potentially ignore and capture any benefits that DG provided because of their market power and information advantages over DG investors. There may therefore be a continued need for regulatory encouragement for distributors to pay DG for benefits they provide if this is not captured within existing markets.

11.2 This section considers whether any non-transmission related benefits and costs arise from ACOT payments, that is, economic benefits other than from reduced or deferred transmission investment and economic costs other than the direct payments.

11.3 As discussed in Section 4, other non-transmission benefits and costs of DG were debated in the development of the pricing principles for DG that were eventually incorporated into Code. As noted in Section 4, the key benefits and costs identified in the documents leading to the development of Schedule 6.4 other than reduced transmission and distribution costs included:

- savings from losses and constraints
- competition benefits
- environmental benefits
- additional costs of less economic generation being constructed.

11.4 Each of these "other benefits" and costs are discussed below.

Savings from losses and constraints

11.5 The economic benefits that arise from reduced losses and constraints are encapsulated in current electricity prices. In particular, wholesale nodal pricing is designed to appropriately price loss and constraints in the wholesale electricity market. Losses and constraints are therefore reflected in wholesale market prices so there would appear to be no substantive case for additional compensation for DG.

11.6 However, in regions with significant DG and where there is a constraint on the transmission system, load in the region can benefit from lower prices from local supply that can continue to operate despite the constraint. ACOT payments do not appear to have been explicitly designed to compensate DGs for the benefits local load receive from access to lower cost supply in constraint situations, although this is no different to grid-connected generation in a similar situation.

11.7 However, if the system was designed to rely on DG in some regions, and a sudden requirement to import high levels of electricity caused constraints in the system, high levels of DG in a region can cause an issue.

53 Facilitating Distributed Generation: a discussion paper, MED, September 2003, p. 7

11.8 It has been suggested that DG can provide loss reduction benefits on distribution lines. In this context, the Counties Power AMP comments that[54]:

> *Distributed generation at lower line capacities can reduce losses…(but) When the output greatly exceeds that demanded by the local area losses can increase significantly unless substantial investment is made in the network. To increase the local load and hence reduce losses, the concept of load centres have been introduced.*

11.9 This suggests, for lower line capacities, there may be benefits of reduced losses on distributor networks, but that DG can also increase losses which may sometimes require capital outlay.

Competition benefits

11.10 Through dispatching its generation into the wholesale market or selling its output by contract to retailers, DGs can provide competition benefits. If a DG plant is built in a constrained region it is likely to be rewarded by higher wholesale prices than if it had been built in a less constrained area, at least initially. In pursuing these gains, its presence in the market will tend to put downward pressure on the prices received by other generation and hence provide flow-on competition benefits to consumers in the same way as grid connected generation.

11.11 The wholesale and retail markets for electricity are considered to be national markets.[55] Hence, there are not separate regional generation markets, and DG competes in the same markets as grid connected generation. It would therefore be inefficient to provide ACOT payments to DGs solely for any competition benefits that would result.

Environmental benefits

11.12 A 2003 MED discussion paper[56] recognised the potential of DG to contribute to improved environmental outcomes. The MED recognised that by incentivising DG, ACOT payments may help to encourage investment in renewable energy. As shown in Appendix C, DG Stations, a high proportion of DG consists of hydro, wind, and geothermal generation. Instruments, such as the emissions trading scheme (ETS), are designed to discourage generation that emits greenhouse gases irrespective of whether the generation is grid connected or distributed. The ETS interacts with the wholesale and retail electricity markets to incentivise less emission intensive generation over the long term. Assuming the ETS produces a price reflecting the cost of the externality arising from greenhouse emissions, it would be inefficient to further subsidise DG for reduction in emissions through ACOT payments. The Authority notes that if the ETS or other mechanisms do not produce a price reflecting the cost of the environmental externality in question this is a matter that other agencies would need to consider, as this is not a matter for the Authority under its statutory objective.

11.13 Nor is it clear that DG is more likely to be renewable generation than grid connected generation. With the exception of peaking plant, all grid-connected

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54 Counties Power Asset Management Plan 2013, Page 104.

55 This was confirmed in a Commerce Commission finding: http://www.comcom.govt.nz/business-competition/competition-enforcement-outcomes/investigation-reports/

56 Facilitating Distributed Generation: a discussion paper, MED, September 2003, p.2.

generation commissioned in the past 5 years has been renewable generation, primarily wind and geothermal. While these large non-DG projects may have larger impacts on the environment (for instance, new roads for site access), they often also have economies of scale and potentially a lesser environmental footprint per MW or GWh. An equivalent supply of DG could involve more schemes and a greater environmental footprint. Compare, for example, a 1 x 100 MW wind farm or hydro dam against 10 x 10 MW separate wind farms or dams across a wider area. There is therefore no obvious compelling reason to favour DG over grid-connected generation for environmental benefits.

Costs resulting from ACOT promoting less economic generation

11.14 The discussion in this paper also indicates there is potential for ACOT to promote construction and operation of less economic generation, as ACOT payments can help to subsidise costs over the life of the plant. This suggests that ACOT could result in an inefficient allocation of capital resources for generation projects that otherwise may not be constructed.

11.15 The allocative inefficiency from subsidisation of inefficient generation is roughly $55,000 per annum[57] or, using an 8% discount rate, $0.4m in present value terms.

11.16 ACOT payments may also displace other projects that have better economies of scale and lower costs of production, which would cause productive inefficiency additional to the estimated allocative efficiency. The Authority estimates that the productive inefficiency that arises from DG, funded from ACOT payments, displacing more efficient generation is in the range of $6.7m to $40m in present value terms. This was determined for a ten year-period, using a discount rate of 8%.[58]

11.17 There is also likely to be an opportunity cost to consumers if ACOT payments mean electricity costs to consumers are greater compared to a counterfactual of ACOT payments targeting avoided costs and security of supply benefits more effectively. The transaction costs of ACOT are a further cost to consumers, although a more targeted set of payments could potentially be involve higher transactions costs.

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57 This was calculated using figures of $50m for the ACOT payment, -0.26 as the elasticity of demand, and total electricity consumption of 38GWh. The allocative inefficiency = 0.5*change in price as a result of the ACOT payment*change in quantity as a result of the ACOT payment. The change in price is equal to the ACOT payment/total demand it applies to = $50m/38TWh total demand = $1.3/MWh. The change in quantity as a result of the ACOT payment is equal to the price elasticity of demand*total demand*change in price all divided by the price to which the increased cost from the ACOT payment applies = (-0.26 * 38TWh * $1.3/MWh)/$150/MWh =85,000MWh. Therefore the allocative inefficiency = 0.5*change in price as a result of the ACOT payment *change in quantity as a result of the ACOT payment = 0.5*$1.30/MWh*85,000MWh = $55,000 per year. This calculation assumes that ACOT is paid by all load. As noted in this working paper this is not actually the case, as some distributors do not pay ACOT and some pay ACOT in a manner that may limit the inefficiency of the payment. This means that the total demand that should be used for this calculation is less than 38TWh.

58 See Appendix D for details of how this estimate was calculated.

Preliminary conclusion on other potential benefits and costs from ACOT payments

11.18 In an open and competitive market economy, the prices paid in a market can be seen as good indicators of the costs of supply, and the value of consumption, or willingness to pay, of consumers. This means that prices received and paid within such a market are likely to provide reasonably good signals for efficient investment and production decisions. Beyond possible avoided transmission and distribution costs, the benefits of DG appear to be encapsulated in wholesale market prices or other mechanisms. There does not therefore appear to be a case for continued regulatory intervention to further compensate DG for other economic benefits in the absence of clear evidence of a market failure.

12 Conclusion

12.1 ACOT payments are generally premised on the basis that reducing the level of demand at a certain grid location may contribute to reducing transmission losses and constraints and therefore investment in transmission assets.

12.2 The analysis in this paper highlights that ACOT payments are nominally labelled as payment for “avoided costs of transmission”. However, as currently structured by at least 18 of the distributors, there is no apparent link to economic costs of transmission. The majority of distributors' ACOT payment policies are based on avoided Transpower charges.

12.3 This paper suggests that this is not promoting efficient outcomes and therefore is inconsistent with the Authority’s statutory objective. Accordingly, the Authority’s preliminary view is that Schedule 6.4 of the Code should be reviewed to ensure that ACOT payments compensate DGs for the benefits DGs provide through avoided economic costs, rather than avoided transmission charges to the distributor. If the Authority decides to undertake such a review, this could be progressed separately from, but potentially in parallel to, the TPM review.

12.4 As a result of investigating the current ACOT payment scheme this paper makes the following findings:

(a) the majority of ACOT payment policies are designed to avoid Transpower’s transmission charges paid by an individual distributor, rather than to reduce future operating or capital costs

(b) the majority of ACOT payment schemes pay DG 100% of the Transpower interconnection charge that would have been incurred in the absence of the DG, and recoup this payment in full from consumers. As such, consumers are unlikely to see any reduction in their charges in the short to medium term. In fact ACOT is estimated to cost consumers $10 per household p.a.[59]

(c) with ACOT payments at a uniform rate across much of the country, there is little effective locational signalling for either DG or transmission investment. The payment rates do not vary according to the number of peaks used in the RCPD calculation (12 or 100). Further, since the Transpower interconnection charge rate is uniform ACOT payments do not vary by location

(d) the ACOT payment provides a financial advantage in favour of DG compared with grid connected generation. This may result in uneconomic projects being developed

(e) Transpower’s planning reports suggest DG places additional costs on the transmission system, not fewer costs

(f) transmission security constraints are likely to be encountered before capacity constraints where generation capacity does not improve security

(g) evidence from Transpower’s asset planning process over the past decade considers DG is insufficiently reliable under the n-1 security standard to

59 Based on an assumption that ACOT does not reduce or avoid transmission or distribution costs, $50 million ACOT divided by total electricity consumption of 38,865,916 MWh = $0.00128/ KWh x 8000 KWh (average’ household consumption) = $10.29 per household.

replace transmission assets with generation alternatives. This view was reinforced in the 2013 planning report[60]

(h) there is evidence that DG can create benefits to distributors by lowering distribution network costs and improving reliability.[61] However, there are also likely to be associated costs and some distributors do not recognise the reliability benefits of DG

(i) the benefits from DG to distributors should increase as energy storage capability increases

(j) other benefits, with the exception of benefits to distributors, appear to be compensated at least partly through other market mechanisms, such as the ETS for emission reduction benefits and wholesale nodal pricing for savings from losses and constraints on the transmission network

(k) if DG provides benefits that are not adequately compensated for by current market mechanisms, or the through Code, where these benefits are recognised in the Authority's statutory objective, compensation for these benefits may be appropriate to the extent that it is efficient. To the extent that these benefits are not recognised by the Authority’s statutory objective, the Authority would provide information it receives on this to the relevant regulating authority or Government department.

60 Transpower 2013, Appendix F.4.

61 For example, Orion AMP 2013, page 6.

Appendix A Disclosed ACOT Payments

Table 4: Disclosed annual ACOT payments by distribution business ($'000's) from Commerce Commission disclosures, installed capacity, and indicative payments from other distribution business publications.

Electricity Distribution Business	2008	2009	2010	2011	Other payment information	Installed Capacity (MW)
Alpine Energy Limited	$0	$0	$0	$0	$0	8
Aurora Energy	$2,819	$4,312	$2,416	$1,250	$6,600	154
Buller Electricity	$0	$0	$0	$0	$0	-
Centralines Limited	$0	$0	$0	$0	$0	
Counties Power	$0	$0	$0	$0	$0	3
Eastland Network	$2,444	$2,083	$2,083	$2,438	$2,527	12
Electra Limited	$0	$0	$0	$0	$0	
Electricity Ashburton	$173	$548	$339	$716	$0	28
Electricity Invercargill	$0	$0	$0	$0	$0	-
Horizon Energy Distribution	$2,181	$2,432	$2,696	$2,845	$0	77
Mainpower New Zealand	$0	$0	$0	$0	$0	-
Marlborough Lines Limited	$57	$49	$46	$82	$0	14
Nelson Electricity Limited	$0	$0	$0	$0	$0	
Network Tasman Limited	$0	$0	$0	$0	$0	2

Electricity Distribution Business	2008	2009	2010	2011	Other payment information	Installed Capacity (MW)
Network Waitaki Limited	$178	$178	$178	$182	$400	-
Northpower Limited	$25	$0	$0	$175	$0	15
Orion New Zealand	$21	$60	$458	$0	$0	8
OtagoNet Joint Venture	$167	$222	$446	$570	$0	21
Powerco Limited	$3,544	$6,590	$6,251	$8,388	$8,800	147
Scanpower Limited	$0	$0	$0	$0	$0	
The Lines Company	$524	$738	$775	$871	$0	17
The Power Company	$225	$323	$521	$1,160	$0	67
Top Energy Limited	$738	$767	$709	$0	$2,300	25
Unison Networks	$0	$0	$2,611	$3,226	$6,200	75
Vector Lines Limited	$7,974	$10,550	$13,129	$10,099	$11,268	29
Waipa Networks Limited	$0	$0	$0	$0	$0	4
WEL Networks	$556	$836	$2,725	$711	$3,600	113
Wellington Electricity Limited	$0	$7	$71	$151	$247	12
Westpower Limited	$554	$964	$680	$946	$1,600	22
Total	**$22,180**	**$30,659**	**$36,135**	**$33,811**	**$43,542**	**850**

Appendix B ACOT Methodology Summary

Table 5: ACOT methodology – brief descriptions from disclosures

Electricity Distribution Business	Notes
Alpine Energy Limited	Methodology considers distributed generation and connection information, but no ACOT mentioned. The main embedded plant (7.5 MW) is not disclosed.
Aurora Energy	ACOT included in standard UOS agreement. General requirement is sizable, reliable, 5 MW and above. Smaller sizes 0.5 to 5.0 MW if approved.
Buller Electricity	Above 10kW, must apply and agree to conditions including ToU metering
Centralines Limited	Currently no qualifying plants, but propose to pass-through 100% of TPNZ interconnection rate of $99.44/kW for the 2013/14 year.
Counties Power	Disclosure suggests six small and one large plant locally, but only the large one receives payments (landfill generation)
Eastland Network	$2,527,000 recorded as ACOT payment. Case by case basis, but up to a determined capacity level (not unlimited).
Electra Limited	Currently less than 20 sites below 5 kW (no large sites). Does not currently make payments, but does not charge for distribution either.
Electricity Ashburton	Will allocate a portion of ACOT, three existing connections above 500kW.
Electricity Invercargill	Currently no distributed generation. Anticipate payments would be on the on basis of the TPNZ charge.
Horizon Energy Distribution	Only payable to generation that reduces TPNZ interconnection charge. No ACOT is available at Edgecumbe due to existing generation. Anticipates a recovery of payments if generation falls significantly.
Mainpower New Zealand	Not applicable as most (and only a few) units of a few kW.
Marlborough Lines Limited	Three embedded generators - full pass-through of regional peak reduction.
Nelson Electricity Limited	Does not provide payments for distributed generation.
Network Tasman	3 small hydro (plus 60 roof-top solar). Contracts include clauses for

Electricity Distribution Business	Notes
Limited	payments for avoided costs - where it is able to be demonstrated. Payment is a pass through of the full $99/kW TPNZ rate.
Network Waitaki Limited	$400k ACOT revenue requirement - will negotiate on case by case.
Northpower Limited	For larger (typically MW plus) sites, credit is based on 12 peaks and pass-through of current TPNZ interconnection rate.
Orion New Zealand	Latest methodology suggests payments of $115/kW based on long run investment cost of network.
OtagoNet Joint Venture	Payments made where generation reduces peak charges - payment process can result in a year delay (arrears).
Powerco Limited	Pays TPNZ rates for ACOT. Disclosures provide table showing $8.8M in payments, split by GXP.
Scanpower Limited	Currently no distributed generation.
The Lines Company	Transmission avoidance credits calculated as per TPNZ charges (adjustment for losses.
The Power Company	Where generation reduces peak charges - currently three generators receiving payments.
Top Energy Limited	Greater than 1 MW - calculated at $2.3M for 2013/14 based on TPNZ rates.
Unison Networks	Approximately $6.2M for central North Island and $0 for Hawke's Bay - uses the 100 peak TPNZ basis.
Vector Lines Limited	Methodology mentions charging incremental costs, rather than avoided transmission.
Waipa Networks Limited	Seeks to avoid people subsidising generation. Very little information provided on distributed generation.
WEL Networks	Share of reduction in peak TPNZ charge. Currently three sites, payment based on performance and individually assessed.
Wellington Electricity Limited	200KVA minimum and deemed to be supporting 100 top peaks. Benefit "direct avoidance" of TPNZ charges. No long term TPNZ benefits are payable by the distributor. Has a slightly complex formula that uses a counterfactual.
Westpower Limited	$1.6M of ACOT - charges that would otherwise be paid to TPNZ

Appendix C Embedded Generation Stations

Table 6: Embedded generation stations type and capacity (sorted by commissioning year).

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
Kongahu	Buller Electricity	Unknown	0	Not given	ORO1101	Buller Electricity	Doesn’t pay ACOT
Plimmerton	Right House	Unknown	0	Not given	PNI0331	Wellington Electricity	Pays ACOT
Southern Landfill	Todd Energy	Other	1.1	Not given	CPK0331	Wellington Electricity	Pays ACOT
Bombay	Greymouth Power Company	Unknown	2.3	Not given	BOB1101	Counties Power	Doesn’t pay ACOT
Mangatawhiri	Counties Power	Hydro	0.2	Not given	BOB0331	Counties Power	Doesn’t pay ACOT
Watercare Cossey's Dam	Counties Power	Hydro	0	Not given	BOB0331	Counties Power	Doesn’t pay ACOT
Watercare Wairoa Dam	Counties Power	Hydro	0	Not given	BOB0331	Counties Power	Doesn’t pay ACOT
Mangatangi Dam	Watercare Services	Hydro	0.6	Not given	BOB0331	Counties Power	Doesn’t pay ACOT
Totara Road	Palmerston North City Council	Thermal	0.8	Not given	LTN0331	Powerco	Pays ACOT

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
Turitea Hydro	Palmerston North City Council	Hydro	0.1	Not given	LTN0331	Powerco	Pays ACOT
Palmerston Nth Mini Hydro	Palmerston North City Council	Hydro	0	Not given	BPE0331	Powerco	Pays ACOT
Ravensbourne	Ravensdown Fertiliser Co-op	Cogeneration	0.5	Not given	HWB0332	Aurora Energy	Pays ACOT
Port Chalmers	Port Otago	Unknown	0	Not given	HWB0331	Aurora Energy	Pays ACOT
Horseshoe Bend	Pioneer Generation	Hydro	4.3	Not given	CYD0331	Aurora Energy	Pays ACOT
Gisborne	Eastland Networks	Unknown	4.5	Not given	GIS0501	Eastland Network	Pays ACOT
Wairoa	Eastland Networks	Unknown	0.8	Not given	WRA0111	Eastland Network	Pays ACOT
Kew Hospital	Kew Hospital	Unknown	0	Not given	INV0331	The Power Company	Pays ACOT
Ravensdown	Vector	Cogeneration	8	Not given	RDF0331	Unison Networks	Pays ACOT
Forest Research	Todd Energy	Thermal	0.3	Not given	ROT0111	Unison Networks	Pays ACOT
Fletcher Forests	Trustpower	Thermal	3.5	Not given	ROT0111	Unison Networks	Pays ACOT
Iwitahi	Radio New	Unknown	0.3	Not given	WRK0331	Unison Networks	Pays ACOT

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
	Zealand						
Kawerau - CHH	Carter Holt Harvey	Cogeneration	27	Not given	KAW0111	Horizon Energy Distribution	Pays ACOT
Marokopa Power Station	Marakopa Generation	Hydro	0.1	Not given	HTI0331	The Lines Company	Pays ACOT
Raetihi	Trustpower	Hydro	0.3	Not given	OKN0111	The Lines Company	Pays ACOT
Marlborough Lines Diesel	Marlborough Lines	Thermal	9	Not given	BLN0331	Marlborough Lines	Pays ACOT
Jackson Estate	Jackson Estate	Backup generation	0.2	Not given	BLN0331	Marlborough Lines	Pays ACOT
Mud House	Kiwi Wine Company	Backup generation	0.2	Not given	BLN0331	Marlborough Lines	Pays ACOT
South Pacific Cellars	South Pacific Cellars	Backup generation	0.2	Not given	BLN0331	Marlborough Lines	Pays ACOT
Cloudy Bay	Indevin	Unknown	0	Not given	BLN0331	Marlborough Lines	Pays ACOT
Government Communications Satellite	Government Communications Satellite	Backup generation	0	Not given	BLN0331	Marlborough Lines	Pays ACOT

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
Indevin	Indevin	Backup generation	0	Not given	BLN0331	Marlborough Lines	Pays ACOT
Whisper Tech	Whisper Tech	Thermal	0	Not given	SBK0331	MainPower NZ	Doesn't pay ACOT
Whangarei	Northland District Health Board	Thermal	0	Not given	MPE0331	Northpower	Pays ACOT
Maungatapere	Trustpower	Thermal	0.5	Not given	MPE0331	Northpower	Pays ACOT
Hornby, Christchurch	Ravensdown Fertiliser Co-op	Thermal	0.7	Not given	ISL0331	Orion New Zealand	Doesn't pay ACOT
Addington	Orion	Unknown	0.4	Not given	ADD0111	Orion New Zealand	Doesn't pay ACOT
Christchurch Hospital Campus	Christchurch District Health	Backup generation	0.3	Not given	ADD0661	Orion New Zealand	Doesn't pay ACOT
Aluminium Diecasting Ltd	Aluminium Diecasting	Unknown	0.2	Not given	BRY0111	Orion New Zealand	Doesn't pay ACOT
Burwood Hospital	Christchurch District Health	Unknown	0.2	Not given	BRY0661	Orion New Zealand	Doesn't pay ACOT
Middleton	CWF Hamilton & Co	Unknown	0.2	Not given	ISL0331	Orion New Zealand	Doesn't pay ACOT
St Albans,	Christchurch City	Unknown	0.2	Not given	PAP0661	Orion New	Doesn't pay

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
Christchurch	Council					Zealand	ACOT
Christchurch Airport (Harewood)	Christchurch Airport Authority	Backup generation	0.1	Not given	ISL0661	Orion New Zealand	Doesn't pay ACOT
Darfield	WD Boyes & Sons	Thermal	0.1	Not given	HOR0331	Orion New Zealand	Doesn't pay ACOT
Templeton	Department of Corrections	Thermal	0.1	Not given	ISL0331	Orion New Zealand	Doesn't pay ACOT
Belfast	Christchurch City Council	Unknown	0	Not given	PAP0111	Orion New Zealand	Doesn't pay ACOT
Crowne Plaza	Crowne Plaza	Unknown	0.1	Not given	ADD0661	Orion New Zealand	Doesn't pay ACOT
FoodStuffs Hickory Place	Foodstuffs (South Island)	Unknown	0	Not given	ISL0331	Orion New Zealand	Doesn't pay ACOT
Simeon Quay	Orion	Backup generation	0.7	Not given	BRY0111	Orion New Zealand	Doesn't pay ACOT
Orion Diesel	Orion	Thermal	0.3	Not given	ADD0661	Orion New Zealand	Doesn't pay ACOT
Orion Diesel II	Orion	Thermal	0.2	Not given	ADD0661	Orion New Zealand	Doesn't pay ACOT

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
Milburn	Department of Corrections	Thermal	0	Not given	BAL0331	OtagoNet Joint Venture	Pays ACOT
Falls Dam	Pioneer Generation	Hydro	1.3	Not given	NSY0331	OtagoNet Joint Venture	Pays ACOT
Stratford Austral Pacific	Austral Pacific Energy	Unknown	1	Not given	SFD0331	Powerco	Pays ACOT
Mokoia Road, Hawera	Swift Energy	Thermal	0.2	Not given	HWA0331	Powerco	Pays ACOT
Drysdale	Drysale Hydro Company	Hydro	0.1	Not given	MTN0331	Powerco	Pays ACOT
Lloyd Mandeno	Trustpower	Hydro	15.6	Not given	TGA0331	Powerco	Pays ACOT
Ballance Agri	Trustpower	Cogeneration	6.5	Not given	MTM0111	Powerco	Pays ACOT
PukePine	PukePine Sawmills	Thermal	0	Not given	TMI0331	Powerco	Pays ACOT
Opunake	Trustpower	Hydro	0.3	Not given	OPK0331	Powerco	Pays ACOT
Pupu Hydro	Pupu Hydro Society	Hydro	0.3	Not given	MPI0661	Network Tasman	Doesn’t pay ACOT
Onekaka	Onekaka Energy	Hydro	1	Not given	MPI0661	Network Tasman	Doesn’t pay ACOT

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
Mataura	Niblick Trust	Hydro	0.9	Not given	GOR0331	The Power Company	Pays ACOT
Maraetai Embedded	Mighty River Power	Hydro	0.1	Not given	WKM2201	The Lines Company	Pays ACOT
Watercare Waitakere	United Networks	Hydro	0	Not given	HEN0331	Vector	Pays ACOT
Redvale Landfill	Waste Management	Other	7	Not given	SVL0331	Vector	Pays ACOT
Watercare Clevedon	Watercare Services	Thermal	0	Not given	TAK0331	Vector	Pays ACOT
Ascot Ave	Manson Developments	Unknown	0.1	Not given	PEN0331	Vector	Pays ACOT
Mansons Developments	Mighty River Power	Unknown	0	Not given	PEN1101	Vector	Pays ACOT
Whitford Landfill	Waste Management	Other	3	Not given	TAK0331	Vector	Pays ACOT
Pacific Steel	Vector	Backup generation	0.2	Not given	MNG0331	Vector	Pays ACOT
Anchor Products	Trustpower	Thermal	3.9	Not given	TMU0111	Waipa Networks	Doesn’t pay ACOT

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
Enfield	Network Waitaki	Unknown	0	Not given	OAM0331	Network Waitaki	Pays ACOT
Omarama	Waitaki Power	Unknown	0	Not given	WTK0331	Network Waitaki	Pays ACOT
Ngahere	Birchfield Minerals	Hydro	0.1	Not given	DOB0331	Westpower	Pays ACOT
Hokitika Diesel	Trustpower	Thermal	3.3	Not given	KUM0661	Westpower	Pays ACOT
Fox	Trustpower	Hydro	0.2	Not given	HKK0661	Westpower	Pays ACOT
Marlborough Lines Diesel II	Marlborough Lines	Thermal	0	Not given	BLN0331	Marlborough Lines	Pays ACOT
Mangorei	Trustpower	Hydro	4.5	1906	CST0331	Powerco	Pays ACOT
Kaniere Forks	Trustpower	Hydro	0.43	1911	HKK0661	Westpower	Pays ACOT
Waihi Station	Trustpower	Hydro	4.7	1913	WRA0111	Eastland Network	Pays ACOT
Kourarau	Genesis Energy	Hydro	0.95	1923	MST0331	Powerco	Pays ACOT
Piriaka	King Country Energy	Hydro	1.8	1924	HTI0331	The Lines Company	Pays ACOT
Monowai	Pioneer Generation	Hydro	6.6	1925	NMA0331	The Power Company	Pays ACOT
Motukawa	Trustpower	Hydro	4.8	1927	HUI0331	Powerco	Pays ACOT

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
Waihopai	Trustpower	Hydro	2.5	1927	BLN0331	Marlborough Lines	Pays ACOT
Kumara	Trustpower	Hydro	6.5	1928	KUM0661	Westpower	Pays ACOT
Dillmans	Trustpower	Hydro	3.5	1928	KUM0661	Westpower	Pays ACOT
Duffers	Trustpower	Hydro	0.5	1928	KUM0661	Westpower	Pays ACOT
McKays Creek	Trustpower	Hydro	1.1	1931	HKK0661	Westpower	Pays ACOT
Arnold	Trustpower	Hydro	3.1	1932	DOB0331	Westpower	Pays ACOT
Brooklyn Power Station	Lloyd Wensley	Hydro	0.2	1934	MOT0111	Network Tasman	Doesn't pay ACOT
Roaring Meg	Pioneer Generation	Hydro	4.2	1936	CML0331	Aurora Energy	Pays ACOT
Wye Creek	Pioneer Generation	Hydro	1.35	1936	FKN0331	Aurora Energy	Pays ACOT
Hinemaiaia A	Trustpower	Hydro	2.4	1939	WRK0331	Unison Networks	Pays ACOT
Highbank	Trustpower	Hydro	25.2	1945	ASB0661	Electricity Ashburton	Pays ACOT
Fraser	Pioneer Generation	Hydro	2.8	1956	CYD0331	Aurora Energy	Pays ACOT

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
Wahapo (Okarito Forks)	Trustpower	Hydro	3.1	1960	HKK0661	Westpower	Pays ACOT
Kuratau	King Country Energy	Hydro	6	1962	ONG0331	The Lines Company	Pays ACOT
Wairere Falls	King Country Energy	Hydro	4.9	1963	ONG0331	The Lines Company	Pays ACOT
Mokauiti	King Country Energy	Hydro	1.9	1963	ONG0331	The Lines Company	Pays ACOT
Hinemaiaia B	Trustpower	Hydro	1.35	1966	WRK0331	Unison Networks	Pays ACOT
Oxburn/Glenorchy	Pioneer Generation	Hydro	0.4	1968	FKN0331	Aurora Energy	Pays ACOT
Lower Mangapapa	Trustpower	Hydro	6	1976	TGA0331	Powerco	Pays ACOT
Wairua Falls	Northpower	Hydro	5	1978	MPE0331	Northpower	Pays ACOT
Aniwhenua	Bay of Plenty Energy	Hydro	25	1979	ANI0331	Horizon Energy Distribution	Pays ACOT
Wellington Hospital	Vector	Cogeneration	10	1981	CPK0331	Wellington Electricity	Pays ACOT
Ruahihi	Trustpower	Hydro	20	1981	TGA0331	Powerco	Pays ACOT
Montalto	Trustpower	Hydro	1.8	1982	ASB0331	Electricity	Pays ACOT

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
						Ashburton	
Hinemaiaia C	Trustpower	Hydro	2.85	1982	WRK0331	Unison Networks	Pays ACOT
Kaimai 5	Trustpower	Hydro	0.35	1982	TGA0331	Powerco	Pays ACOT
Teviot	Pioneer Generation	Hydro	10.5	1983	CYD0331	Aurora Energy	Pays ACOT
Paerau	Trustpower	Hydro	10	1984	NSY0331	OtagoNet Joint Venture	Pays ACOT
Patearoa	Trustpower	Hydro	2.25	1984	NSY0331	OtagoNet Joint Venture	Pays ACOT
Kawerau - BOP	Bay of Plenty Energy	Geothermal	6.4	1989	KAW0111	Horizon Energy Distribution	Pays ACOT
Rosedale Landfill	EnviroWaste	Other	2.8	1992	ALB0331	Vector	Pays ACOT
Greenmount Landfill	EnviroWaste	Other	5.5	1992	OTA0221	Vector	Pays ACOT
Wellington Wind Turbine	Meridian Energy	Wind	0.2	1993	CPK0331	Wellington Electricity	Pays ACOT
Silverstream Landfill	Mighty River Power	Other	2.7	1994	HAY0331	Wellington Electricity	Pays ACOT
Bay Milk	Bay of Plenty	Cogeneration	10	1996	EDG0331	Horizon Energy	Pays ACOT

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
Edgecumbe	Energy					Distribution	
Hau Nui	Genesis Energy	Wind	8.45	1996	GYT0331	Powerco	Pays ACOT
Christchurch City Wastewater	Orion	Other	3.2	1996	BRY0111	Orion New Zealand	Doesn't pay ACOT
Rotokawa	Mighty River Power	Geothermal	34	1997	WRK0331	Unison Networks	Pays ACOT
Ngawha	Top Energy	Geothermal	25	1998	KOE0331	Top Energy	Doesn't pay ACOT
Opuha	Alpine Energy	Hydro	7.5	1999	ABY0111	Alpine Energy	Doesn't pay ACOT
Te Rapa	Contact Energy	Cogeneration	44	1999	TWH0331	WEL Networks	Pays ACOT
Tararua Stage 1	Trustpower	Wind	31.7	1999	LTN0331	Powerco	Pays ACOT
Blue Mountain Lumber	Blue Mountain Lumber	Cogeneration	1.4	2000	GOR0331	The Power Company	Pays ACOT
Christchurch Wind Turbine	Orion	Wind	0.5	2003	SPN0331	Orion New Zealand	Doesn't pay ACOT
Watercare Mangere	Watercare Services	Cogeneration	7	2003	MNG0331	Vector	Pays ACOT
Horotiu Landfill	Green Energy	Other	0.9	2004	TWH0331	WEL Networks	Pays ACOT

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
Tararua Stage 2	Trustpower	Wind	36.3	2004	BPE0331	Powerco	Pays ACOT
Southbridge Wind	Energy3	Wind	0.1	2005	SPN0331	Orion New Zealand	Doesn't pay ACOT
Pan Pac	Pan Pac Forest Products	Cogeneration	12.8	2005	WHI0111	Unison Networks	Pays ACOT
Auckland District Hospital	Auckland District Hospital Board	Cogeneration	3.6	2005	PEN0331	Vector	Pays ACOT
White Hill	Meridian Energy	Wind	58	2007	NMA0331	The Power Company	Pays ACOT
Mangapehi	Clearwater Hydro	Hydro	1.6	2008	HTI0331	The Lines Company	Pays ACOT
Tirohia Landfill	H.G. Leach & Co.	Other	1	2008	WKO0331	Powerco	Pays ACOT
Kawerau - KA24	Geothermal Developments	Geothermal	8.3	2008	KAW0111	Horizon Energy Distribution	Pays ACOT
Deep Stream	Trustpower	Hydro	5	2008	HWB0331	Aurora Energy	Pays ACOT
Horseshoe Bend Wind	Pioneer Generation	Wind	2.25	2009	CYD0331	Aurora Energy	Pays ACOT
Hampton Downs Landfill	EnviroWaste	Other	4	2009	MER0331	WEL Networks	Pays ACOT

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
Mangahewa	Todd Energy	Thermal	9	2009	HUI0331	Powerco	Pays ACOT
Matawai	Clearwater Hydro	Hydro	2	2009	GIS0501	Eastland Network	Pays ACOT
Kowhai	Pioneer Generation	Hydro	1.9	2010	CYD0331	Aurora Energy	Pays ACOT
Talla Burn	Talla Burn Generation	Hydro	2.15	2010	CYD0331	Aurora Energy	Pays ACOT
Cleardale	MainPower	Hydro	0.9	2010	ASB0661	Electricity Ashburton	Pays ACOT
Te Huka	Contact Energy	Geothermal	23	2010	WRK0331	Unison Networks	Pays ACOT
Weld Cone Wind	Energy3	Wind	0.75	2010	BLN0331	Marlborough Lines	Pays ACOT
Mahinerangi	Trustpower	Wind	36	2011	HWB0331	Aurora Energy	Pays ACOT
Lulworth Wind	Energy3	Wind	1	2011	BLN0331	Marlborough Lines	Pays ACOT
Marsden Diesel	Trustpower	Thermal	9	2011	BRB0331	Northpower	Pays ACOT
Te Rere Hau	New Zealand Wind Farms	Wind	48.5	2011	TWC2201	Powerco	Pays ACOT
Te Uku	WEL Networks /	Wind	64.4	2011	TWH0331	WEL Networks	Pays ACOT

Station name	Owner name	Generation type	Capacity	Station name	Owner name	Distributor	Whether the distributor pays ACOT
	Meridian Energy						
Mount Stuart	Pioneer Generation	Wind	7.65	2011	BAL0331	OtagoNet Joint Venture	Pays ACOT
Kawerau - TOPP 1	Norske Skog Tasman	Geothermal	25	2012	KAW0112	Horizon Energy Distribution	Pays ACOT

Appendix D Calculation of productive inefficiency resulting from ACOT payments

D.1 This Appendix describes the Authority's estimate of the productive efficiency impact as a result of ACOT-funded generation displacing potentially more efficient generation. It assesses generation investments made over the last 10 years and determines a present value based on a 10 year horizon with a discount rate of 8%.

D.2 As well as affecting productivity efficiency, ACOT-funded generation may also affect network investment needs (either positively or negatively), but the estimate does not consider this. This is discussed in sections 7-9 of this working paper.

D.3 The cost and quantity of generation constructed over the last 10 years is used to estimate productive efficiency. ACOT may also have:

- kept pre-2004 DG in service, where it would have been more efficient to decommission it
- incentivised pre-2004 discretionary DG to run in possible RCPD periods, in which it could have been more cost-effective to run other generation instead.

D.4 However, these inefficiencies are likely to be second-order in size given that it is usually more efficient to keep existing generation in service than to build new generation, and that a relatively small proportion of pre-2004 DG can be operated in a discretionary manner.

D.5 ACOT (in its current form) has only been in place for six years, and the RCPD charge for an even shorter period. So ACOT (in its current form) cannot have affected generation build decisions between seven and ten years ago. However, DGs were already receiving avoided cost of transmission payments prior to 2006.[62] Therefore, it seems reasonable to consider the effects of DG investment over the last decade at least.

D.6 For the purposes of the estimate, "ACOT-funded generation" is defined as all generation published by the Authority[63]that is identified as being fully embedded, and having been commissioned between 2004 and 2013. This is based on the assumptions that:

- all such generation receives ACOT payments (although, as noted in Table 5 in Appendix B, this is not the case)
- the amount of DG that is eligible for ACOT but does not exist in the Authority's published list of generation is not significant.[64]

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62 For instance, see Genesis' submission on the draft 'Electricity Governance (Connection of Distributed Generation) Regulations 2006, which notes that "many of the large network companies have a mechanism of returning the avoided costs of transmission to distributed generators". Available at: https://www.genesisenergy.co.nz/c/document_library/get_file?uuid=223f7ac4-98b0-4f60-9d11-7bcf0210a9a6&groupId=10314.

63 http://www.ea.govt.nz/dmsdocument/8621.

64 In fact there may be some generation in the 0.2 kW – 1 MW range that is eligible for ACOT but not in the spreadsheet – but the quantity is likely to be so small that the effect on efficiency is not material.

D.7 On this basis, there is 332 MW of ACOT-funded generation, more than half of which is wind. This generation produces an estimated 1370 GWh per year, assuming load factors of:

- 90% for geothermal
- 40% for wind
- 60% for hydro
- 20% for all other types.

D.8 For simplicity, it is assumed that this ACOT-funded generation falls into three categories:

(a) generation that would have been constructed whether or not ACOT was available

(b) generation that was profitable with ACOT, but would have been just below the break-even point (and not proceeded) without ACOT

(c) generation that was just above the break-even point with ACOT, but would have been unprofitable (and not proceeded) without ACOT.

In reality, some generation would have fallen between categories B and C (which differ only in degree of profitability), but this is ignored for simplicity.

D.9 The inefficiency resulting from ACOT payments is:

- minimal for category A generation, because such generation would have been constructed whether ACOT was available or not. Where such generation is discretionary, ACOT payments may have increased operating costs by incentivising the plant to operate in possible RCPD periods, even where energy prices may not have justified such operation. However this inefficiency is of second-order size at most.
- minimal for category B generation, because such generation is nearly as economic as the alternative that would have proceeded if ACOT was not available. As above, there may be some inefficiency from incentivising discretionary DG to operate in possible RCPD periods, but this is second-order at most.
- possibly substantial for category C generation, because such generation is significantly less economic than the alternative that would have proceeded if ACOT was not available.

D.10 To estimate the productive inefficiency from ACOT, the focus is therefore on the inefficiency stemming from constructing category C generation.

D.11 Let *G* be a category C ACOT-funded generator, and assume that if ACOT was not available, the alternative would have been to construct *G'* – a similar amount of capacity, of a similar type, but more cost-effective (perhaps due in part to economies of scale) and in a different location. Assume that when ACOT is taken into account *G* is just above the break-even point of *G'*, and that *G* and *G'* would earn the same net operating revenue excluding ACOT. Then the difference in long-run marginal cost between *G* and *G'* must be just below the average ACOT payment received by *G*'s output, in $/MWh terms. This difference is the productive efficiency loss stemming from constructing *G* instead of *G'*.

D.12 On a present value basis, therefore, the productive efficiency loss over the next 10 years resulting from ACOT-funded generation displacing potentially more efficient generation over the last 10 years can be estimated as:

I = Sum over *y*=2014…2023 of ((1-*r*)*y*-2013 * *AS* * *AFG* * *PC*)

where:

r is the real discount rate (assume 0.08 or 8%)

AS is the average ACOT payment in $/MWh terms (estimated at $15/MWh, based on a payment of $50M spread over 727 MW of generation operating at a mean load factor of 50%. [65]

AFG is the amount of ACOT-funded generation, as MWh per year (estimated at 1,370,000 MWh, as above)

PC is the proportion of ACOT-funded generation that falls into category C.

D.13 *PC* is unknown but a scenario-based approach can be used to produce a range of estimates of *I*.

D.14 A reasonable lower bound is to assume *PC* = 0.05 (i.e. less than 20 MW of ACOT-funded generation was significantly uneconomic and would not have proceeded without ACOT), in which case *I* = $6.7m (present value). [66]

D.15 A reasonable upper bound is to assume *PC* = 0.3 (i.e. about 100 MW of ACOT-funded generation was significantly uneconomic and would not have proceeded without ACOT), in which case *I* = $40m (present value).[67]

65 Note that this is a lower load factor than that used in the main paper of 67%. This is because a high proportion of more recently constructed DG is wind, which would mean a lower load factor is appropriate.

66 Note that this estimated lower bound is just an assumed lower bound and has not been estimated.

67 Note that this estimated upper bound is just an assumed upper bound and has not been estimated.