

# Review of distributed generation pricing principles

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## Decisions and reasons

6 December 2016



## Executive Summary

The Electricity Authority (Authority) published a consultation paper in May 2016 in which we proposed to address two problems with the distributed generation pricing principles (DGPPs), the ‘connection services issue’ and the ‘avoided cost of transmission’ (ACOT) issue, which are described below.<sup>1</sup> The paper put forward four options, with the first of the options as the preferred option.

Having considered submissions received on the proposal, we have decided to defer consideration of the connection services issue and to adopt one of the alternative options for addressing the ACOT issue discussed in the consultation paper.<sup>2</sup> We have decided to adjust the DGPPs to better ensure that, under the regulated terms provided in Part 6 of the Electricity Industry Participation Code 2010 (Code), distributors will pay ACOT to distributed generation only if the arrangement would efficiently defer or reduce transmission investment costs.

The purpose of this paper is to explain these decisions and our reasons for making them.

### **We have decided to amend the Code so that distributed generation that does not efficiently defer or reduce grid costs will no longer receive ACOT payments under the regulated terms**

#### **ACOT creates a subsidy that is not in consumers’ interests**

Some generators, by operating at times of peak network demand, allow Transpower to reduce its grid costs. Other generators do not. The location of the generator is a key factor. A generator is more likely to defer or reduce grid costs if it is in a region where generation is scarce relative to load and the grid needs to be upgraded soon in order to bring more electricity into the region. Many distributed generators, however, are in regions (such as the lower South Island) where generation is plentiful relative to load and the grid is used mainly to take electricity out of the region. Distributed generators in such regions may actually *add to* grid costs rather than reducing them.

Efficiency requires that investors and owners of distributed generators face an incentive to provide transmission network (grid) support services (ie, to invest in or operate distributed generators so as to allow Transpower to efficiently defer or reduce grid costs). In principle, such an incentive could potentially be provided through a market price, a transmission network charge or a side-payment (such as an ACOT payment). For efficiency, only those distributed generators that do efficiently defer or reduce grid costs should be rewarded for doing so.

Under the DGPPs, distributors typically pay ACOT to the owners of large distributed generators (over around 100kW), even the ones that don’t help to defer or reduce grid costs. This over-payment causes inefficiency. We call this the ‘ACOT issue’.

Owners of distributed generators that do not defer or reduce grid costs are benefiting from a subsidy. Consumers fund the subsidy by paying higher electricity prices – about \$50 to \$60

<sup>1</sup> The pricing principles in Schedule 6.4 of the Code require distributors to pay distributed generation owners for reductions in transmission and distribution costs that arise from connecting distributed generation to their network. In practice, payments have mainly been transmission-related (they have been made for reductions in transmission charges). Reductions in transmission costs are often termed the Avoided Cost of Transmission (ACOT). Reductions in distribution costs are termed the Avoided Cost of Distribution (ACOD).

<sup>2</sup> The alternative option we have adopted was called Alternative 3 in the May 2016 consultation paper. We have made some minor modifications to Alternative 3, including changes to the phasing of implementation, the level of payment and the ultimate decision-maker (which is the Authority, rather than Transpower).

million a year more.<sup>3</sup> In many cases they get nothing in return. We estimate that consumers are paying around \$25 million – \$35 million per annum without receiving an associated benefit. ACOT is paid to owners of distributed generation. Over two thirds of distributed generation capacity is owned by just four big companies (Contact, Genesis, Meridian and Trustpower).

Subsidies cause inefficiency and waste. ACOT is no different. We have calculated the net value lost to society from inefficiencies caused by ACOT at around \$33m in present value terms. This includes inefficient investment (\$23m), inefficient reinvestment in existing generation (\$5.5m) and inefficient operation (\$4.4m).<sup>4</sup>

#### **Case study: Peaker plant**

A 10 MW diesel-fired generator receives around \$1 million per year in ACOT payments. It does not reduce transmission costs as there was already ample transmission capacity into the region.

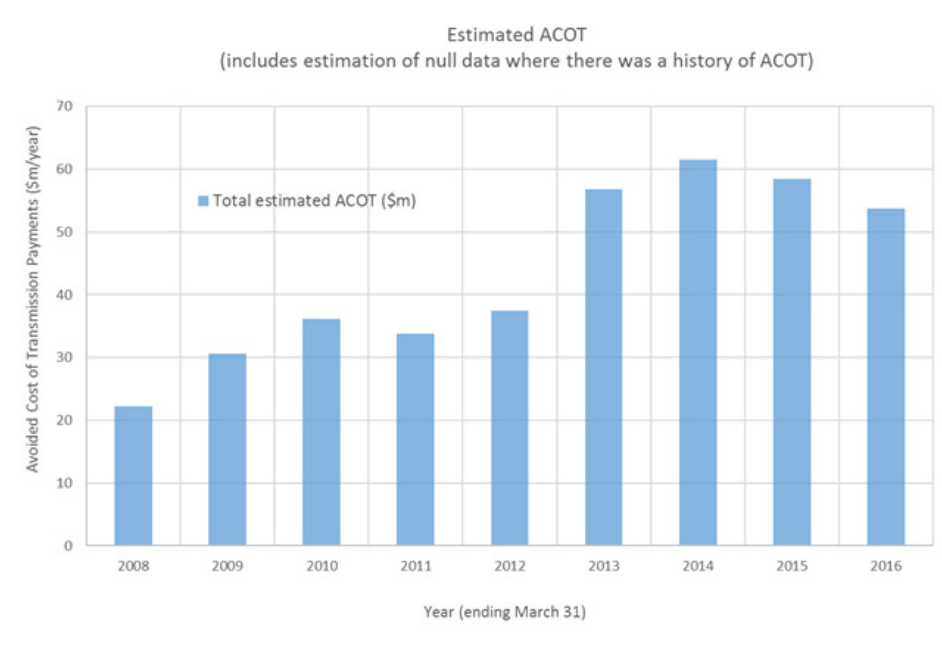
This is a wealth transfer of \$1 million per year from consumers to the owner of the diesel-fired generator, with no associated benefit.

To receive this payment the generator targets 150 peak periods and this incurs fuel costs of approximately \$225,000 per year. This generation provides some energy benefit, but based on the spot price during times of operation this was around \$75,000 per year. This means that ultimately there is a net economic cost of around \$150,000 per year (\$75,000 minus \$225,000) from inefficiently burning diesel (not counting environmental costs due to carbon emissions).

The size of the problem has grown over time. The annual quantity of ACOT payments appears to have more than doubled over the last eight years, from around \$20m in 2008 to around \$50m in 2016 (see Figure 1). This growth was caused by higher transmission charges and more distributed generation; it doesn't reflect an increased need for grid support. Quite the opposite: the need for grid support is generally lower than it was in 2008, as grid capacity has expanded since that time. Most of the growth in capacity of distributed generation is in parts of the country where distributed generators are unlikely to defer or reduce grid costs. This means the subsidy has inflated: consumers are now paying more for less benefit than they were getting in 2008.

<sup>3</sup> We mention this wealth transfer away from consumers and towards owners of distributed generation as it may be of interest to other policy-makers. The Authority doesn't take wealth transfers into account unless they have efficiency effects. The Authority's objective requires it to act when doing so "grows the pie" (produces long-term benefits to consumers overall). Wealth transfers are about dividing up the pie.

<sup>4</sup> These costs are present values derived from the cost benefit analysis set out in appendix C, in the "current TPM" scenario.

**Figure 1: ACOT payments appear to have increased substantially**

Source: Electricity Authority

- Notes:
1. This maps the allowance for the 'avoided transmission charges' category, which is mainly ACOT payments to distributed generation but also includes payments relating to transfer of ownership of transmission lines to distributors
  2. We've adjusted for some apparent errors in the recent data relating to mis-entry of data

### **ACOT does not promote competition**

ACOT also tilts the playing field in favour of distributed generators, against grid-connected generators and also small-scale distributed generation (eg solar panels), demand response and other transmission alternatives. This is because ACOT is only paid to larger generators connected to a distribution network.<sup>5</sup> This situation harms consumers in the long-term. It can also lead to arbitrary outcomes. For example, consider a generator that does not efficiently defer or reduce grid costs and is connected to the grid. It will not receive ACOT payments. If the electricity lines it is connected to are purchased from Transpower by the local distributor, its owner would begin receiving ACOT payments simply because of that change of ownership of the electricity lines.

### **We have decided to address the ACOT issue by amending the DGPPs**

We have decided to address the ACOT issue by amending the DGPPs (instead of removing them). A key result of this Code amendment is that under the regulated terms distributors will make ACOT payments only to existing distributed generation that is required in order for Transpower to meet the Grid Reliability Standards in the Code.

The Code amendment places responsibility for identifying such distributed generation with the party that has the best information and ability to carry out this task: Transpower. Transpower will assess which distributed generators in each region are required for it to meet the Grid Reliability Standards, and advise the Authority of its findings. The Authority will decide, based on Transpower's advice, which existing distributed generation should receive ACOT payments under the regulated terms.

<sup>5</sup> ACOT is typically not paid to small-scale distributed generation (eg below 100kW capacity).

This change will better ensure that distributors will only make payments under the regulated terms in exchange for genuine grid support services (ie, where distributed generation allows Transpower to meet the Grid Reliability Standards). The Code amendment will substantially reduce payment of ACOT to the owners of distributed generators that don't help to defer or reduce grid costs.

Further, distributors will no longer make ACOT payments to new distributed generation. Transpower will be responsible for assessing the need for additional grid support from new distributed generation where that would be the cheapest way to achieve the required level of transmission service. In this respect, the decision is the same as our May 2016 proposal.

All of the other elements of the DGPPs and regulated terms will remain in place.

### **The Code amendment will benefit consumers**

The Code amendment will benefit consumers because it will largely end the inefficient subsidy aspect of the current ACOT arrangements, remove inefficient incentives on investment and operation of distributed generation, and enhance competition.

The Authority is currently reviewing the transmission pricing methodology (TPM) so as to better promote efficient investment in transmission and other electricity assets and the efficient operation of the electricity industry. The results of this review will affect the size of the inefficiencies caused by the ACOT issue. So the benefits of the Code amendment described in this decision paper will vary depending on if and when the Authority makes proposed changes to the TPM.

By reducing the inefficient incentives caused by ACOT, the Code amendment will create substantial long-term net benefits to consumers. In the absence of any change to the TPM, the Code amendment will produce net benefits of approximately \$33 million.<sup>6</sup> If the proposed changes to the TPM take effect from April 2020, then the Code amendment will yield net benefits of approximately \$2 million. Under all scenarios considered the net benefit was positive.

While our decision will benefit consumers, it will not be popular with some of the companies that have benefited from the ACOT subsidy. We are ending an arrangement that has led to higher corporate profits at the expense of consumers. We expect the affected businesses to complain, and to argue loudly for keeping the subsidy. However, our objective is not to be popular with the industry. The Authority has taken this decision because it will promote the long-term benefit of consumers. We note submissions in support of our proposal by consumers including the Major Electricity Users Group.

The Code amendment will also improve competition by removing an artificial advantage in favour of distributed generators against grid-connected generators and also small-scale

#### **Key benefits:**

Efficiency gains \$33m (PV)

Consumers save \$25-35m pa

Levels playing field for demand response and small-scale solar

Levels playing field for grid-connected generators

Properly rewards distributed generators that genuinely defer or reduce grid costs

<sup>6</sup> This is a present value derived from the cost benefit analysis set out in appendix C. It is the sum of the cost figures set out earlier in the Executive Summary.

distributed generation (eg solar panels), demand response and other transmission alternatives (ie, ACOT payments that are not justified by network support services).

We decided not to change the rate of ACOT payments for existing distributed generation at this time, as we want to reduce transactions costs and transition risk. This decision is likely to be generous to owners of distributed generation in most cases as ACOT rates increased by 79% over the last eight years. However, this is a transitional arrangement, and we expect arrangements to be refined at a future point so that ACOT payments do not exceed the transmission benefits being provided by distributed generation.

### **The Code amendment won't have adverse competition or reliability impacts**

Stakeholders made a number of arguments about our May 2016 proposal that are also relevant to our decision to amend the DGPPs.

Some parties argued that the DGPPs proposal would reduce reliability because many distributed generators might not operate at times of peak demand. We don't agree. Transpower will identify distributed generation that provides reliability benefits and should receive ACOT payments, which will ensure that those benefits are not lost.

In any case, the Authority considers that generators will overwhelmingly continue to operate at peak times as these are the times they can earn more revenue from the wholesale electricity market. Further, distributed generation does not operate at peak times more reliably than other forms of generation. In fact, the reverse is true. Distributed generation represents up to 25% of all generation at off-peak times, but this proportion *falls* to less than 15% at peak times.<sup>7</sup>

Some submitters contend that our decision will increase wholesale electricity prices, especially at peak demand times. However, we don't expect any permanent effect on average wholesale prices. As noted above, generators will overwhelmingly continue to operate at peak times. A handful of high-running-cost (eg diesel) distributed generators might stop operating at peak, causing wholesale prices to rise temporarily, but this would attract new generation (or demand response), pushing prices down again.<sup>8</sup> In any case, our decision means consumers will pay lower overall electricity prices, as the price drop from ending the ACOT subsidy will far outweigh any temporary rise in wholesale prices.

Some parties have argued that our decision will undermine dynamic efficiency because it undermines a settled regulatory bargain. We don't agree. There has been no long-standing historic regulatory policy for distributors to make ACOT payments to distributed generation in the same way that they do now. Further, investors in distributed generation could not reasonably expect the ACOT subsidy to continue, when it so clearly leads to poor outcomes for consumers. In any case, keeping payments that are obviously inefficient would encourage and reward rent-seeking behaviour. It would also discourage people from acting efficiently in future. We think the best way to promote regulatory certainty and the best investment climate for New Zealand in the long-term is for the Authority to consistently pursue its statutory objective.

### **Other matters not relevant to our decision**

Some stakeholders claimed that our decision will hurt the environment because most distributed generators have low emissions. While this is outside our scope, we still think it's important to set the record straight. Distributed generators do not have significantly lower emissions than grid-connected generators (around 80% of both categories of generator have low emissions).

<sup>7</sup> Source: Electricity Authority analysis, based on data for the year beginning September 2015.

<sup>8</sup> See Concept Consulting Group, *Winter capacity margin – potential effect of recent transmission pricing and distributed generation proposals*, November 2016.

Further, over 95% of new grid-connected and distributed generation proposals are for renewable generators.<sup>9</sup> This suggests that generation entering the market in future will most likely be overwhelmingly renewable, regardless of our proposal. We also note that low-emission generators will continue to be rewarded through the Emissions Trading Scheme.

Some submitters argued that our decision would hurt people who live outside the main centres. This is also outside our scope. However, we disagree. Most grid-connected generators are located outside the main centres, and will continue to employ people in those regions. Consumers throughout the country will benefit as they will no longer pay ACOT to generators without receiving grid support benefits in return—so their electricity prices will go down.

In any case, we don't expect many generators to shut down – only a handful of inefficient diesel generators that are high cost to run and don't provide any grid support benefits. Distributed generators that do create real grid support benefits will continue to receive ACOT payments.

Further, the Code amendment reduces financial risk for distributed generators (compared to the Authority's May 2016 DGPPs proposal) because we are no longer proposing to remove the regulated price ceiling on distribution charges. This change reduces the impact of the proposal on distributed generators by more than 50% (based on analysis carried out by PWC for the IEGA).<sup>10</sup>

Some stakeholders argued that our decision will harm new technologies like small-scale solar and demand response. We think the opposite. In fact, our decision will eliminate the artificial advantage that distributed generation receives from ACOT payments. Owners of small-scale distributed generation (like solar panels) and batteries do not typically receive ACOT subsidies. Our decision will help to level the playing field.

The following table clarifies some existing misunderstandings of our earlier proposal (which may also apply to our decision):

**Table 1: Clarifying misunderstandings about the Authority's proposal**

Misunderstandings	Clarification
The Authority assumes that 40% of distributed generation will close	Distributed generators that defer or reduce grid costs will be paid. We actually assume only 6% will close (high-running cost diesel generators). The 40% figure is a misunderstanding of one of our CBA assumptions.
The proposal will lead to economic losses of \$1.3 billion	The proposal will result in a net economic benefit of \$33m or \$2m, depending on changes to transmission pricing.
Carbon emissions will go up	Distributed generation is not lower-emission

<sup>9</sup> To be precise, over 95% of proposals that are planned to progress, and that have received planning consents. Information is not available in all cases on whether proposed new generation will be grid-connected or distributed, however, larger plant are more likely to be grid-connected and smaller plant are more likely to be distributed. Refer to the Authority's Proposed generating plant update, available on the Authority's EMI website: [http://www.emi.ea.govt.nz/Datasets/Browse?directory=%2FProposed&parentDirectory=%2FDatasets%2FWhole%2FGeneration%2FGeneration\\_fleet](http://www.emi.ea.govt.nz/Datasets/Browse?directory=%2FProposed&parentDirectory=%2FDatasets%2FWhole%2FGeneration%2FGeneration_fleet).

<sup>10</sup> PWC, 20 July 2016, *Independent review of the potential impact of proposed regulatory changes on distributed (electricity) generators* (prepared for Pioneer Energy).



Misunderstandings	Clarification
	than grid connected generation. 95% of new generation is low-emissions generation.
Regional areas will be harmed	Very few distributed generators will cease operation. Regional areas will continue to benefit from grid-connected generation.

### **Transpower will be required to apply a test for identifying existing distributed generation that reduces or defers grid costs**

After considering submissions on Transpower's incentive to prefer network solutions over distributed generation, the Authority has decided to require Transpower to apply a test defined in the Code for identifying existing distributed generation that is required to meet the Grid Reliability Standards.

The Authority will make the final decision on which distributed generation will receive ACOT under the default DGPP terms, after reviewing Transpower's advice.

### **The Code amendment will take effect in four phases**

Many submitters said that there wasn't enough time to implement our proposal. We have decided to postpone implementation of the Code amendment by at least a year in all regions.

The Code amendment will have effect from:

- 1 April 2018 for distributed generation located in the lower South Island (LSI) transmission region (previously 1 April 2017)
- 1 October 2018 for distributed generation located in the lower North Island (LNI) transmission region (previously 1 April 2017)
- 1 April 2019 for distributed generation located in the upper North Island (UNI) transmission region (previously 1 April 2018)
- 1 October 2019 for distributed generation located in the upper South Island (USI) transmission region<sup>11</sup> (previously 1 April 2018).

This phased approach to implementation will allow time for Transpower to identify distributed generation that can efficiently defer or reduce grid costs. It will keep Transpower's task at a manageable size initially, before ramping up over time. And by getting the implementation process underway it will allow the net benefits of the new ACOT payment regime to begin to flow to consumers as soon as possible.

The LSI is the region considered least vulnerable to grid reliability problems. It also has fewer distributed generators than the LNI region. Beginning with the LSI is a measured approach that will reduce any risks that might have been associated with the Code amendment.

### **The ACOT arrangements are expected to be further refined over time**

The new arrangements are an important step forward in improving ACOT provisions – by ensuring that consumers are not required to fund ACOT unless distributed generation provides genuine transmission benefits. However, further refinement of the arrangements is expected

<sup>11</sup> These four transmission pricing regions were defined for transmission pricing purposes in 2006. [https://www.transpower.co.nz/sites/default/files/uncontrolled\\_docs/TPM\\_2006\\_%20Supplementary\\_Material.pdf](https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/TPM_2006_%20Supplementary_Material.pdf)



over time – especially to ensure the rate of ACOT payments do not exceed transmission benefits.

In future, nodal prices in the wholesale electricity market may be sufficient to encourage the operating and investment responses required for efficient management of transmission network constraints. To the extent nodal prices do not provide a sufficient signal, a long-run marginal cost (LRMC) charge may be desirable. The proposed new TPM would allow Transpower to introduce an LRMC charge. If either of these changes occurs, the new ACOT arrangements might no longer be needed, or could require refinement.

If the TPM guidelines change, then in parallel with submitting a new TPM to the Authority for approval, Transpower should also recommend to the Authority further adjustments to the DGPPs that will promote efficiency and competitive neutrality between demand response, distributed generation and grid-connected generation.

If the current TPM remains in force then we will review the new ACOT arrangements for each region by no later than five years after the new arrangements have commenced for each region.

In either case, the review will make sure that the pricing arrangements in place will provide ongoing incentives for efficient investment and operation of distributed generation.

## **We have decided not to remove the DGPPs from the Code**

### **The regulated price ceiling will remain in place for now**

The DGPPs set out that under the regulated terms, distributors will charge owners of distributed generation no more than the incremental cost for connection and distribution services (ie, a regulated price ceiling). The regulated price ceiling does not promote efficiency. This is the ‘connection services issue’. The May 2016 proposal was to address the connection services issue by removing the DGPPs, which would have ended the regulated price ceiling.

However, many stakeholders submitted that, by removing the price ceiling’s protection, the proposal would have let distributors use monopoly power to overcharge owners of distributed generation for connection services. This might not promote competition, as it would inefficiently tilt the playing field against distributed generation, in favour of grid-connected generators. We think the risks these submissions raise require further consideration.

After considering submissions, we have decided to leave the regulated price ceiling in place for the time being. We will not address the connection services issue at this time.

### **We will revisit this issue to better promote competitive neutrality**

However, we still consider that the current arrangements may not promote competitive neutrality. The regulated price ceiling may provide distributed generators with an artificial competitive advantage over grid-connected generators and also over other technologies that could compete with distributed generation in providing various services. These other technologies include small scale distributed generators (including solar panels), batteries and other modes of demand response. This would not promote competition, and may lead to higher costs and less choice for consumers in the long term.

The Authority intends to revisit this issue and resolve it in a way that will promote efficiency and competitive neutrality between distributed generators, grid-connected generators and other technologies. Our objective will be that providers of similar services compete on a level playing field. Generators should face efficient connection charges. Pricing of network services should be service-based, cost-reflective, subsidy-free and consistent with pricing that would apply in a

workably competitive market. Common costs should be allocated in a way that minimises distortions to consumption and investment decisions.

We intend to address the inefficiencies and competition problems associated with this issue, but will defer consideration of it until work has progressed on other projects including the TPM review and the distribution pricing review. If the TPM guidelines change and Transpower proposes a new TPM to the Authority, then it should have a role in the consideration of this issue through its recommended adjustments to the DGPPs (noted above).

## **Consultation**

In making the decisions set out in this paper, the Authority considered whether it would be appropriate to consult further in relation to the matter. We have decided that further consultation is not necessary because our decisions have no material features that interested parties have been deprived of an opportunity to comment on in the original consultation. In summary, our decisions only depart from our original preferred option in the following respects:

- (a) deferral of consideration of the connection services issue
- (b) delaying implementation of the measures to address the ACOT issue
- (c) leaving ACOT in place for certain existing distributed generation rather than removing it for all
- (d) giving the final decision-making as to which distributed generation continues to receive ACOT to the Authority on the recommendation of Transpower.

The Authority also took into account that its final proposal is similar in many respects to Alternative 3 in the consultation paper.

The Authority does not consider that any of these changes is fundamental, significantly affects consultees or is based on reasoning not previously signalled to consultees.

The Authority found the submissions on the consultation paper of great assistance in its consideration of this matter, and the submissions have influenced, and in the Authority's view improved, the final proposal.

## Contents

Executive Summary	2
We have decided to amend the Code so that distributed generation that does not efficiently defer or reduce grid costs will no longer receive ACOT payments under the regulated terms	2
ACOT creates a subsidy that is not in consumers' interests	2
ACOT does not promote competition	4
We have decided to address the ACOT issue by amending the DGPPs	4
The Code amendment will benefit consumers	5
The Code amendment won't have adverse competition or reliability impacts	6
Other matters not relevant to our decision	6
Transpower will be required to apply a test for identifying existing distributed generation that reduces or defers grid costs	8
The Code amendment will take effect in four phases	8
The ACOT arrangements are expected to be further refined over time	8
We have decided not to remove the DGPPs from the Code	9
The regulated price ceiling will remain in place for now	9
We will revisit this issue to better promote competitive neutrality	9
Consultation	10
1 In May 2016 we proposed to remove the DGPPs from the Code in order to address two issues	14
The DGPPs establish a default charging regime for distributed generation and distributors	14
We published a consultation paper in May 2016	14
The DGPPs inefficiently encourage distributed generation to avoid transmission charges rather than to defer or avoid transmission costs (the ACOT issue)	15
DGPPs reward distributed generation for avoided transmission charges	15
Poor signalling of transmission-related effects has inefficient results	15
Case study: Wind farm development	16
A 30 MW wind farm can be connected to the national grid or a local distribution network. It will not reduce transmission costs in either case because of the location of the wind farm.	16
The national grid connection option will produce the cheapest power in overall terms, but that means the developer will not qualify for ACOT payments. These are worth around \$13 million over the life of the project.	16
The developer decides to connect to the distribution network even though it makes the electricity more expensive to produce, because this cost will be more than offset by the ACOT payments the developer will receive. These net costs are ultimately paid by consumers.	16
DGPPs may encourage inefficient investment in notionally embedded generation	16
Avoided transmission charges have increased substantially	16
The TPM review is relevant	18
The DGPPs allow distributed generation owners to avoid paying a share of common costs (the connection services issue)	18
We proposed to remove the DGPPs on the basis that this would address both the ACOT issue and the connection services issue	18
Removing the DGPPs would address the ACOT issue	18
Our view was that removing the DGPPs would address the connection services issue	19
2 We have made two decisions	21
We will address the ACOT issue by amending the Code so that distributed generation that is not required for the Grid Reliability Standards will not get ACOT payments under the default terms	21

	We will defer addressing the connection services issue and will not remove the DGPPs from the Code at this time	23
	Consultation	24
3	Changing the DGPPs so that distributed generation that that is not required for the Grid Reliability Standards will no longer receive ACOT payments will promote the long-term benefit of consumers	25
	The amendment promotes the Authority's statutory objective	25
	The amendment will produce net economic benefits	26
	The Code amendment addresses the ACOT issue	26
	Amending the Code so ACOT is paid only to distributed generation that is required to meet the Grid Reliability Standards will promote efficiency	27
	Distributors will make ACOT payments under regulated terms only where distributed generation provides a transmission benefit	28
	Distributed generation owners will still be paid for the services they provide, and pay for the services they require	29
	A phased transition allows time for Transpower to carry out the required analysis and make recommendations to the Authority	32
	Stakeholders raised a number of issues relevant to the Code amendment	37
	Transpower may not have the right incentives	37
	Concerns about reliability of supply are unfounded	38
	The Code amendment will not cause any permanent change in wholesale electricity prices	39
	The Code amendment will not harm retail market competition	39
	The Code amendment will not affect voltage support and losses	40
	The best way to promote regulatory certainty and dynamic efficiency is to be predictable and consistently follow the statutory objective	41
	The Code amendment will not cause any net increase in transaction costs	42
	The Authority has extended the timeframe for implementation	43
	Transpower has sufficient resources to assess the ability of distributed generation to efficiently defer or reduce grid costs	43
	We have taken into account contractual requirements to keep paying ACOT	44
	Issues raised in submissions that are of interest to other policy-makers	44
4	Removing the DGPPs now might not promote the long-term benefit of consumers	47
	Addressing the connection services problem in the way proposed might not promote the Authority's statutory objective	47
	The benefits of addressing the connection services problem now might not exceed the costs	47
	Stakeholders raised three key issues relating specifically to the connection services issue	47
	The proposal would have allowed distributors to use their monopoly power to overcharge for connection services	48
	The proposal would have exacerbated the risk that distributors underpay ACOD	49
	The proposal would have undermined competitive neutrality	50
Appendix A	Code amendment	52
Appendix B	List of submitters	55
Appendix C	Economic effects of the Code amendment	57
	Evaluation framework	57
	Potential incremental costs	57
	Impact on reliability of supply	58
	Impact on transmission network costs	58
	Impact on distribution network costs	58
	Impact on consumer prices	59

Transaction costs	59
Dynamic efficiency	60
Potential incremental benefits	68
Benefit from reduced inefficient operation of existing generation	68
Benefit from reduced inefficient investment in new generation	70
Benefit from reduced inefficient retention of existing generation	72
Benefit from reduced allocative efficiency losses arising from lower prices for consumers	75
Assessed benefits – current TPM	76
Total assessed benefits – prospective AOB-based TPM	78
Relative weightings to be applied to counterfactuals	81
Comparison of current analysis with May 2016 consultation paper	82
Gross benefits to customers	84
Appendix D Concept Consulting Group, Winter capacity margin – potential effect of recent transmission pricing and distributed generation proposals	85

## Tables

Table 1: Clarifying misunderstandings about the Authority's proposal	7
Table 2: Estimated benefits under current TPM - \$m present value	26
Table 3: Services that distributed generation can provide, and services that distributed generation can require	30
Table 4: Services that distributed generation can provide relating to matters outside the Authority's statutory objective	31
Table 5 List of parties making submissions	55
Table 6: Estimated benefits under current TPM - \$m present value*	77
Table 7: Estimated benefits under AOB-based TPM - \$m present value*	80
Table 8: Comparison of May 2016 and current estimated benefits \$m present value	83
Table 9: Gross benefits to consumers \$m present value	84

## Figures

Figure 1: ACOT payments appear to have increased substantially	4
Figure 2: ACOT payments appear to have increased substantially	17
Figure 3: Timeframe for transition	36
Figure 4: Interconnection rate	65
Figure 5: Sensitivity of base case estimate to key assumptions – current TPM	78
Figure 6: Sensitivity of base case estimate to key assumptions – prospective TPM	81
Figure 7: Net benefits under base case assumptions \$m present value	82

# 1 In May 2016 we proposed to remove the DGPPs from the Code in order to address two issues

## **The DGPPs establish a default charging regime for distributed generation and distributors**

- 1.1 Generation connected to a local distribution network is called distributed generation. Distributed generation owners and distributors can negotiate agreements to receive and provide services to each other. If they do not agree terms (and do not have a pre-existing contract already in place), Part 6 of the Code provides for default terms, called regulated terms, to apply. Part 6 includes a set of distributed generation pricing principles (DGPPs) which form the basis of the charges under the regulated terms.
- 1.2 The Authority has repeatedly signalled its intention to review the DGPPs. The Authority's 2012/13 work programme noted that a review of DGPPs was to be carried out as part of the Authority's review of distribution pricing. The Authority also noted its intention to review the DGPPs in response to submissions on the Part 6 operational review in 2012. The issue also received attention during the TPM consultation. Interested parties raised the issue (in response to an issues paper in October 2012 and at a conference in May 2013) that proposed amendments to the TPM would impact on the DGPP generally and the level of ACOT payments specifically. So in November 2013, the Authority released a working paper on ACOT payments, which identified issues with the current DGPP regime, and proposed a review of Schedule 6.4 of the Code.<sup>12</sup>

## **We published a consultation paper in May 2016**

- 1.3 The Authority published a consultation paper in May 2016 in which we proposed to remove the DGPPs from Part 6 of the Code. The objective of the proposal was to ensure the DGPPs promote competition in, reliable supply by, and efficient operation of the electricity industry for the long-term benefit of consumers.<sup>13</sup> It was intended to address two key problems we had identified with the DGPPs: the 'ACOT issue' and the 'connection services issue'. These issues are summarised in the following subsections.<sup>14</sup>
- 1.4 We received 54 submissions on the consultation paper.<sup>15</sup> The parties who made submissions are listed in Appendix B. A summary of submissions is available from the Authority's website at <http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-part-6-dg-pricing-principles/development/authority-decision-on-the-review-of-dgpps-and-acot>.

<sup>12</sup> The 'connection services' issue had previously been raised by stakeholders submitting on the Operational review of part 6 consultation paper published in September 2012. Refer summary of submissions available at: <http://www.ea.govt.nz/dmsdocument/15749>.

<sup>13</sup> This is the Electricity Authority's statutory objective, which is set out in section 15 of the Electricity Industry Act 2010.

<sup>14</sup> For a more detailed discussion of these issues, refer to the Authority's May 2016 consultation paper, *Review of distributed generation pricing principles*, which is available on the Authority's website at this link: <http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-part-6-dg-pricing-principles/consultations/#c15998>

<sup>15</sup> Including three confidential submissions.

## **The DGPPs inefficiently encourage distributed generation to avoid transmission charges rather than to defer or avoid transmission costs (the ACOT issue)**

- 1.5 The DGPPs reward owners of distributed generation for avoided transmission charges, rather than signalling the true value of any transmission-related services provided or used by distributed generation. This encourages inefficient investment in distributed generation. It also encourages inefficient operation of distributed generation, and distorts competition in favour of distributed generation compared to alternatives.

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

- 1.6 Distributed generation can reduce, increase, or have no effect on transmission capital or operating costs, depending on the circumstances. Locating distributed generation in a region that imports energy may defer the need for grid upgrades, and therefore reduce transmission costs.<sup>16</sup> Conversely, adding distributed generation in a region that exports energy may not reduce costs, and may even increase costs if it requires more investment in the grid.
- 1.7 To promote overall efficiency, ACOT payments made to distributed generation need to reward operation that efficiently avoids transmission costs.
- 1.8 The DGPPs do not achieve this. Instead, they require distributors to signal to distributed generators the avoided/additional transmission charges the distributor would otherwise pay in the absence of distributed generation.<sup>17</sup> These charges do not necessarily reflect the avoided or additional transmission costs. As a result, there can be over-signalling or under-signalling of transmission costs and benefits.

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

- 1.9 The following effects can result from over-signalling of transmission-related benefits associated with distributed generation:
- (a) Distributed generators may operate at times when the incremental running costs exceed any benefit from reduced or deferred transmission investment costs.
  - (b) Distributed generation that does not reduce or defer transmission investment costs may be retained, even though the incremental retention cost exceeds any transmission benefit.
  - (c) Investment in new distributed generation may be made, or located, based on a transmission charge signal, while the transmission-related benefits are non-existent or even negative.
- 1.10 These effects would result in efficiency losses, because the cost of actions to reduce or defer transmission investment will exceed the real benefit of that activity.

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<sup>16</sup> This assumes that distributed generation will be operating during the periods that drive the need for additional transmission capacity.

<sup>17</sup> In respect of transmission-related effects, the charges are the relevant issue because Schedule 6.4 requires each distributor to consider the transmission costs that it would avoid as a result of the connection of the distributed generation. And for distributors, transmission costs predominantly means transmission charges.



**Case study: Wind farm development**

A 30 MW wind farm can be connected to the national grid or a local distribution network. It will not reduce transmission costs in either case because of the location of the wind farm.

The national grid connection option will produce the cheapest power in overall terms, but that means the developer will not qualify for ACOT payments. These are worth around \$13 million over the life of the project.

The developer decides to connect to the distribution network even though it makes the electricity more expensive to produce, because this cost will be more than offset by the ACOT payments the developer will receive. These net costs are ultimately paid by consumers.

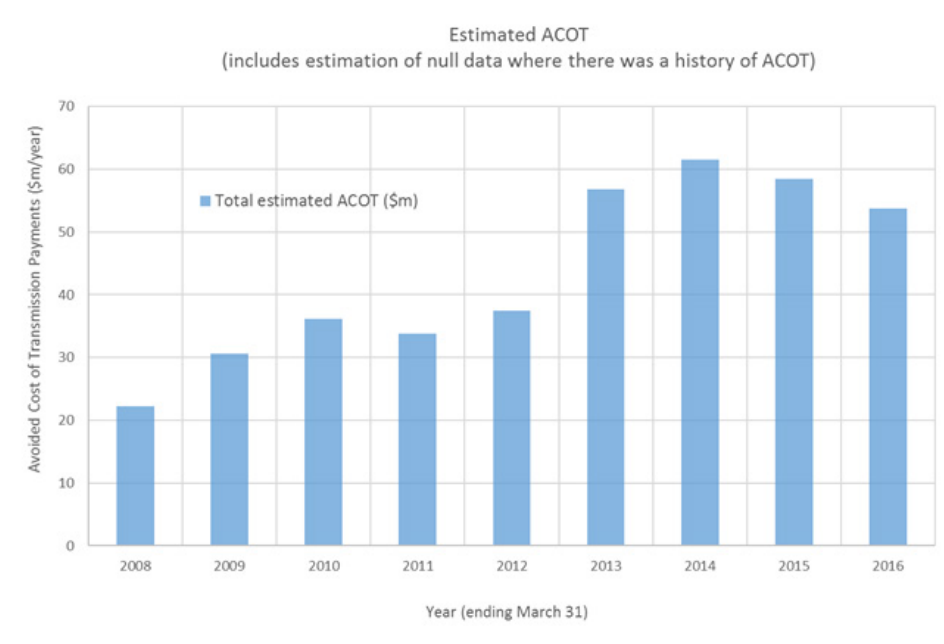
**DGPPs may encourage inefficient investment in notionally embedded generation**

- 1.11 The DGPPs only apply to distributed generation (ie, generation physically connected to distribution networks). However, they may also affect decisions about investing in and operating notionally embedded generators.
- 1.12 Notionally embedded generators are connected to the grid. However, Transpower has agreed (under a Code provision) with the owners of such generation plant, following detailed assessment, to calculate transmission charges *as if* the generation plant was connected to the distribution network and not to the grid.
- 1.13 The existence of the DGPPs means that notionally embedded generators receive payments equivalent to ACOT (less an allowance for the cost of connecting to the distribution network). Thus, the DGPPs may also encourage inefficient investment in and operation of grid-connected generation that is notionally embedded.
- 1.14 When we use the term “distributed generation” in this paper, we mean notionally embedded generation as well as distributed generation, unless stated otherwise.

**Avoided transmission charges have increased substantially**

- 1.15 For the year ended March 2016, ACOT payments are estimated at \$54 million. (In fact this figure is for “avoided transmission charges”, however, the Authority considers that distributors would have paid most of this sum to owners of distributed generation in the form of ACOT payments.<sup>18</sup>) As Figure 2 shows, ACOT payments appear to have more than doubled over the eight years to 2016.

<sup>18</sup> The Authority understands that most of the \$54 million was for payments to distributed generation. However, it also includes allowances for instances where distributors purchased an asset from Transpower. Prior to 2015, the information disclosures did not distinguish between avoided transmission charge allowances for distributed generation and purchased assets. Purchases of assets from Transpower reduce the transmission charge for the relevant distributor. The purchased assets are rolled into the value of the regulatory asset base of the distributor, and treated as any other asset. As an incentive for such purchases, price-regulated distributors receive a recoverable cost equal to their avoided transmission costs for a period of 5 years from and including the year in which the assets are acquired. It is not possible to separately identify the purchased asset component of avoided transmission costs from the public information disclosures. However, the Authority understands these to be a relatively modest proportion of the total allowance. This inability to separate the purchased asset component of avoided transmission costs applied up to and including the 2013/14 disclosure (after which they are disclosed separately).

**Figure 2: ACOT payments appear to have increased substantially**

Source: Electricity Authority

Notes:

1. This maps the allowance for the 'avoided transmission charges' category, which is mainly ACOT payments to distributed generation but also includes payments relating to transfer of ownership of transmission lines to distributors
2. We've adjusted for some apparent errors in the recent data relating to mis-entry of data

- 1.16 Two facts about this increase in ACOT payments are concerning. First, the increase coincides with a substantial expansion of transmission capacity, which we would generally expect to reduce the benefit of investing in distributed generation. Second, much of the growth has occurred in the LNI and LSI regions, where major transmission investments are not expected to be needed in the near future (so distributed generation is unlikely to defer or reduce grid costs).
- 1.17 This suggests that a large proportion of ACOT payments (possibly most) provide little or no benefit in terms of deferral of transmission costs. At a minimum, it is highly questionable whether the growth over six years of approximately \$25 million in annual ACOT payments in the lower South Island and lower North Island yields equivalent value in transmission benefits.
- 1.18 Instead, it is likely that consumers are paying an extra cost of around \$25 million – \$35 million<sup>19</sup> per annum without receiving an associated benefit.<sup>20</sup> This transfer from consumers to some owners of distributed generation creates efficiency losses.

<sup>19</sup> The lower estimate is based on the growth in ACOT payments in the lower South Island and lower North Island between 2008 and 2014. The higher estimate is based on the view that most of the total ACOT payments in these regions (\$37 million in 2014) are not providing a transmission-related benefit.

<sup>20</sup> While distributors that pay ACOT receive an offsetting credit on their individual transmission charges, because Transpower is subject to an overall revenue cap, it will be expected to reallocate charges among its customers to make up for such 'lost' revenue (ie, any ACOT payments that do not genuinely reduce transmission costs). Accordingly, in overall terms, customers are expected to pay the sum of the ACOT allowances plus the transmission charges required for Transpower to reach its revenue cap.

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

- 1.19 The inefficiencies resulting from ACOT are influenced by the degree of misalignment between transmission charges and transmission costs.
- 1.20 The Authority is currently reviewing the TPM guidelines, and considers that there is potential for alternative options to the current TPM to better promote the Authority's statutory objective. If a new TPM results from the review, the new TPM is likely (among other things) to reduce the misalignment between transmission charges and costs.
- 1.21 However, it is not certain that the review will lead to a change to the TPM guidelines, so the Authority has considered two scenarios: one where the TPM remains the same and another where the TPM changes in line with the Authority's proposals. Further, any change to the TPM would take some years to implement. Even with a change to the TPM, it is unlikely that transmission charges and costs will align in all situations. In our cost-benefit analysis of the Code amendment, we assume that the proposed new TPM will reduce ACOT-related inefficiencies by 95% in the base case.
- 1.22 There may also be practical difficulty in applying the concept of an 'avoided transmission charge', depending on the nature of any change to the TPM. This is because it may be difficult for distributors and owners of distributed generation to assess the effect of individual distributed generation plants on transmission charges.
- 1.23 For these reasons, a new TPM alone is unlikely to address fully the problems discussed above.

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

- 1.24 The DGPPs do not promote efficiency because they prevent distributors from setting prices for distributed generation that include a share of common network costs.
- 1.25 To promote overall efficiency, the prices charged for distribution services should at least cover the incremental cost of that service and not exceed the standalone cost (the cost of the next best alternative).
- 1.26 The DGPPs do not promote efficiency because they make incremental cost the upper limit for charges paid by owners of distributed generation for connection services. Given that "connection services" includes distribution services provided to distributed generation, this means owners of distributed generation are not required to pay a share of common network costs.<sup>21</sup>
- 1.27 While it may be efficient for owners of distributed generation not to contribute to common costs in some situations, it is unclear why this would be efficient in all cases.

### **We proposed to remove the DGPPs on the basis that this would address both the ACOT issue and the connection services issue**

#### **Removing the DGPPs would address the ACOT issue**

- 1.28 Removing the DGPPs would leave Transpower, rather than distributors, responsible for paying distributed generation that defer or reduce grid costs.
- 1.29 In the consultation paper we explained our view that this change would promote the Authority's statutory objective in the following ways:

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<sup>21</sup> At least in their capacity as owners of distributed generation as defined under the Code.

- (a) It would support the efficiency limb by reducing incentives for inefficient investment in and/or operation of distributed generation that does not reduce transmission network costs.
  - (b) It would support the competition limb because it would reduce the scope for distributed generation to be artificially advantaged, relative to grid-connected generation.
  - (c) It would not detract from the reliability limb. Where distributed generation provides a genuine ACOT service, it will continue to receive ACOT payments. As part of its assessment of where distributed generation can efficiently defer or reduce grid costs, Transpower would take into account any reliability benefits provided by distributed generation. More generally, to the extent that distributed generation provides other reliability benefits (incentivised via sale of energy), the proposal will not affect those incentives.
- 1.30 We have not changed our view that removing the DGPPs would address the ACOT issue. However, we became aware that this change would cause other problems, which are described later in this paper.<sup>22</sup> So we are now addressing the ACOT issue using another mechanism.<sup>23</sup>

**Our view was that removing the DGPPs would address the connection services issue**

- 1.31 When we made our proposal in May 2016, our view was that removing the DGPPs would address the connection services issue because distributors would no longer be required (by the DGPPs) to treat distributed generation on a preferred basis when they set charges for distribution services.
- 1.32 In the consultation paper we explained our view that this change would promote the Authority's statutory objective in the following ways:
- (a) The proposal would support the efficiency limb by better allowing distributors to adopt service-based pricing structures across all users of distribution networks, including owners of distributed generation.
  - (b) The proposal would not have a major effect on the competition limb. However, by making under-pricing of distribution services to distributed generation owners less likely, it may better promote efficiency-enhancing competition between distributed generation and grid-connected generation.
  - (c) The proposal would not detract from the reliability limb. Where distributed generation is needed to provide a local reliability benefit (ie, avoid investment to reinforce the distribution network to address a constraint) this can be recognised via avoided cost of distribution (ACOD) payments. Where distributed generation provides a wider reliability benefit, the wholesale electricity market provides the appropriate incentives, and removing the DGPPs will not alter those incentives.

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<sup>22</sup> See discussion in chapter 4 under the heading Stakeholders raised three key issues relating specifically to the connection services issue.

<sup>23</sup> In particular, we have adopted one of the alternative options for addressing the ACOT issue from the consultation paper (Alternative 3), with some minor modifications. See chapter 2.

1.33 However, after considering issues raised in submissions, we have now decided not to address the connection services issue at this time.<sup>24</sup>

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<sup>24</sup> See chapter 4.

## 2 We have made two decisions

### **We will address the ACOT issue by amending the Code so that distributed generation that is not required for the Grid Reliability Standards will not get ACOT payments under the default terms**

- 2.1 The Authority has decided to amend the Code, changing the DGPPs so that:
- (a) distributors will make ACOT payments to an owner of existing distributed generation under the regulated terms only if the distributed generator in question can assist Transpower to meet the Grid Reliability Standards in the Code
  - (b) distributors will no longer make ACOT payments to new distributed generation. Transpower will be responsible for assessing the need for additional grid support from new distributed generation where that would be the cheapest way to achieve the required level of transmission service.
- 2.2 The Code amendment will insert in the DGPPs a new provision such that, for an existing distributed generator, distributors are not required to take transmission costs into account under the regulated terms unless the Authority has decided that the distributed generator is one that should receive ACOT payments. The Authority will make this decision based on advice from Transpower on whether the distributed generator is required during the three-year period leading up to April 2020 in order for Transpower to meet the Grid Reliability Standards in the Code. The Code amendment is set out at Appendix A.
- 2.3 For existing distributed generation, the Code will provide for a process along the following lines:
- (a) Transpower will apply a test to assess which distributed generators located in the relevant transmission region (eg, LSI) are required, individually or collectively, for the power system to meet the Grid Reliability Standards.
  - (b) Transpower will provide its assessment to the Authority (with supporting analysis).
  - (c) The Authority will review Transpower's assessment, and decide, based on Transpower's advice, which distributed generation will qualify for ACOT payments from distributors under the default terms. The Authority will publish this determination.
- 2.4 Under this option, a distributor subject to price control will be able to recover the cost of approved ACOT payments from its load customers under the current Input Methodologies.
- 2.5 We have adopted a phased approach to implementation. The Code amendment will have effect from:
- (a) 1 April 2018 for distributed generation located in the LSI transmission region (previously 1 April 2017)
  - (b) 1 October 2018 for distributed generation located in the LNI transmission region (previously 1 April 2017)
  - (c) 1 April 2019 for distributed generation located in the UNI transmission region (previously 1 April 2018)

- (d) 1 October 2019 for distributed generation located in the USI transmission region (previously 1 April 2018).
- 2.6 The new arrangements are an important step forward in improving ACOT provisions - by ensuring that consumers are not required to fund ACOT unless distributed generation provides genuine transmission benefits. However, further refinement of the arrangements is expected over time - especially to better match the rate of ACOT payments with the size of transmission benefits. The Authority will review the effectiveness of the new ACOT arrangements by no later than five years after the new arrangements have commenced.
- 2.7 We expect some important changes in the environment may have occurred within that five-year time period. There is potential for changes to the way nodal prices in the wholesale electricity market are determined (eg, changes are expected through the Authority's real-time pricing project). These changes may be sufficient to encourage the operating and investment responses required for efficient management of transmission network constraints. There is also potential for the introduction of a long-run marginal cost (LRMC) transmission charge (to the extent nodal prices do not provide a sufficient signal). The proposed new TPM would allow Transpower to introduce a LRMC charge. Either of these changes might mean the DGPPs should be reconsidered.
- 2.8 If the TPM guidelines change, then after the publication of the TPM guidelines, and when Transpower proposes a new TPM to the Authority, Transpower should have a role in the review of ACOT arrangements. This review would be in the context of current and future nodal pricing for the wholesale electricity market and proposed TPM arrangements, Transpower should also consider the ACOT arrangements (including relevant provisions in the Code) that are relevant to its TPM proposal. In parallel with submitting a new TPM to the Authority for approval, Transpower should also recommend to the Authority further adjustments to the ACOT arrangements that will promote efficiency and competitive neutrality between demand response, distributed generation and grid-connected generation.
- 2.9 If the current TPM remains in force then we will review the new ACOT arrangements for each region by no later than five years after the new arrangements have commenced for each region.
- 2.10 In the review we (and Transpower) will consider any relevant changes in circumstances and make whatever changes are required to ensure that the pricing arrangements in place provide ongoing incentives for efficient investment and operation of distributed generation.
- 2.11 The Code amendment was one of the alternative ways to address the ACOT issue that was considered in the May 2016 consultation paper (it was called Alternative 3). We have adopted Alternative 3 with some minor modifications.
- 2.12 The Code amendment will place responsibility for identifying distributed generation that is required in order for Transpower to meet the Grid Reliability Standards with the party that has the best information and ability to do so: Transpower.
- 2.13 However, after considering submissions on its proposal, the Authority considers that it is not appropriate to leave Transpower with sole responsibility for determining ACOT payments to existing distributed generation. Transpower may not have the appropriate incentives to make efficient decisions on payment of ACOT to existing distributed



generation that can efficiently defer or reduce grid costs. In particular, Transpower might have the incentive to either:

- (a) under-pay ACOT (taking advantage of distributed generation with sunk costs) or
- (b) over-pay ACOT (to avoid controversy and public dispute with distributed generation owners).

- 2.14 To address these concerns, we have made two changes. First, we have included in the Code amendment a test (based on the Grid Reliability Standards) that Transpower must apply to identify existing distributed generation that provides transmission benefits. Distributed generation will be considered “required” even if it is only required for a brief period in order for Transpower to meet the Grid Reliability Standards.
- 2.15 Second, we have decided that the Authority will make the final decision on which distributed generation should receive ACOT payments (after reviewing Transpower’s advice and analysis). As a result, distributors will only make payments in exchange for genuine grid support services (ie, where the distributed generation allows Transpower to defer or reduce the costs of transmission).
- 2.16 For the distributed generation that will continue to receive ACOT payments under the regulated terms, our decision does not change the rate. We have considered changing the rate of payment. Our May 2016 proposal envisaged that rates would be agreed between Transpower and distributed generation. However, we decided against this approach in respect of existing distributed generation, in part to reduce transactions costs and transition risk.
- 2.17 We recognise that this decision is likely to be generous in most cases with respect to existing distributed generation (as the existing rate based on avoided transmission charges is likely in many cases to exceed the costs avoided by the distributed generation). Indeed, interconnection charges (and so ACOT rates) have increased by 79% over the last eight years. This increase does not reflect an increase in the grid support benefits provided by distributed generation. However, this is a transitional arrangement that will be replaced in due course with a more efficient arrangement. For example, we expect a new TPM will go a considerable way towards addressing the rate issue.

**We will defer addressing the connection services issue and will not remove the DGPPs from the Code at this time**

- 2.18 After considering issues raised in submissions, we have decided not to proceed at this stage with the proposed Code amendment to remove the DGPPs from the Code.
- 2.19 The regulated price ceiling on distribution charges to distributed generation on the default terms will remain in place for the time being. We are not proposing to change this aspect of the DGPPs.
- 2.20 This decision means we will not address the connection services issue at this time. We will defer consideration of this issue until work has progressed on other projects including the TPM and the distribution pricing review.
- 2.21 The Authority intends to address the connection services issue in a way that will promote competitive neutrality between different technologies and modes of generation and demand response.

## Consultation

- 2.22 In making the decisions set out in this paper, the Authority considered whether it would be appropriate to consult further in relation to the matter. We have decided that further consultation is not necessary because our decisions have no material features that interested parties have been deprived of an opportunity to comment on in the original consultation. In summary, our decisions only depart from our original preferred option in the following respects:
- (a) deferral of consideration of the connection services issue
  - (b) delaying implementation of the measures to address the ACOT issue
  - (c) leaving ACOT in place for certain existing distributed generation rather than removing it for all
  - (d) giving the final decision-making as to which distributed generation continues to receive ACOT to the Authority on the recommendation of Transpower.
- 2.23 The Authority also took into account that its final proposal is similar in many respects to Alternative 3 in the consultation paper.
- 2.24 The Authority does not consider that any of these changes is fundamental, significantly affects consultees or is based on reasoning not previously signalled to consultees.
- 2.25 The Authority found the submissions on the consultation paper of great assistance in its consideration of this matter, and the submissions have influenced, and in the Authority's view improved, the final proposal.
- 2.26 In due course we will consult with affected parties before publishing any list of the distributed generation in each region that should receive ACOT payments (after reviewing Transpower's advice and analysis).

### 3 Changing the DGPPs so that distributed generation that that is not required for the Grid Reliability Standards will no longer receive ACOT payments will promote the long-term benefit of consumers

#### **The amendment promotes the Authority's statutory objective**

- 3.1 After considering all submissions on its proposal, the Authority considers the Code amendment will deliver long-term benefits to consumers by promoting competition in, and efficient operation of, the electricity industry (ie, the first and third limbs of the Authority's statutory objective). The amendment will not materially affect reliability of supply (the second limb of the Authority's statutory objective).
- 3.2 The specific benefits of the Code amendment are:
- (a) It supports the efficiency limb by substantially reducing payment of ACOT to the owners of distributed generators that don't help to defer or reduce grid costs, and so reducing incentives for inefficient investment in and/or operation of distributed generation that does not defer or reduce grid costs.
  - (b) It supports the competition limb because it will reduce the scope for distributed generation to be artificially advantaged, relative to grid-connected generation and also small-scale distributed generation (eg solar panels), demand response and other transmission alternatives.
  - (c) It does not detract from the reliability limb. Where distributed generation provides a genuine grid support service, it will continue to receive ACOT payments. As part of its advice to the Authority, Transpower will take into account any reliability benefits provided by distributed generation. More generally, to the extent that distributed generation provides other reliability benefits (incentivised via sale of energy), the proposal will not affect those incentives.
- 3.3 The Authority has decided on a phased approach to implementation, and a later start date, as this will:
- (a) allow time for Transpower to identify the distributed generators that are required to meet the Grid Reliability Standards and advise the Authority
  - (b) keep Transpower's task at a manageable size in the first year, before ramping up in the following year, while allowing the net benefits of the new ACOT payment regime to begin to flow to consumers as soon as possible
  - (c) reduce any risks that might have been associated with the Code amendment.
- 3.4 As a result of considering submissions, the Authority has decided to introduce as part of the Code amendment a test (based on the Grid Reliability Standards) that Transpower must apply in identifying distributed generation that provides transmission benefits. Submitters raised concerns around Transpower's incentives to prefer network solutions over distributed generation that led us to form this view. These concerns are discussed in more detail later in this paper under the heading "Transpower may not have the right incentives".

## The amendment will produce net economic benefits

- 3.5 We have carried out analysis to estimate the economic costs and benefits of the proposal to remove ACOT from the DGPP, relative to the current DGPP. The analysis builds on the information in the May 2016 DGPP consultation paper, but is substantially revised in a number of areas to:
- reflect the Authority's revised Code amendment
  - set out assumptions in more detail, including more information regarding the basis for key judgements
  - address specific issues raised in submissions.
- 3.6 The results of the Authority's current review of the TPM will affect the benefits of the Code amendment. We considered two scenarios: one where the TPM remains as it is currently and another where the TPM changes in line with the Authority's proposals.
- 3.7 The Code amendment is expected to yield net benefits of approximately \$33 million in the scenario where the current TPM continues to apply. Table 2 summarises the results of the analysis described above. It shows the estimated economic benefits of the DGPP proposals, under the current TPM.

**Table 2: Estimated benefits under current TPM - \$m present value**

Current TPM \$m - present value	Expected economic benefits \$m PV		
	Lower	Base case	Higher
Operations	1.3	4.4	8.0
Reinvestment	1.5	5.5	13.6
Investment	4.7	22.9	56.8
Allocative	0.1	0.2	0.2
<b>Total</b>	<b>7.6</b>	<b>33.0</b>	<b>78.7</b>

- 3.8 The Code amendment is not expected to give rise to any material increase in costs in overall terms. For this reason, the figures in Table 2 also correspond to the estimated net benefits from implementing the DGPP proposals.
- 3.9 The Code amendment is also expected to yield net benefits of approximately \$2 million in a scenario in which a new TPM is introduced. In this scenario we assume that a new TPM is able to reduce ACOT-related efficiency losses by 95%, compared to the current TPM. While a new TPM should be able to remove most of the inefficiencies caused by ACOT, it would be unrealistic to expect removal of all inefficiency.
- 3.10 Under no scenarios considered was the net benefit negative.
- 3.11 The Authority's analysis on the economic effects of the Code amendment is set out at Appendix C.

## The Code amendment addresses the ACOT issue

- 3.12 The Code amendment will substantially reduce payment of ACOT to the owners of distributed generators that don't help to defer or reduce grid costs, as:
- distributors will no longer make ACOT payments to those existing distributed generation that do not assist Transpower to meet the Grid Reliability Standards

- (b) Transpower will only make ACOT payments to those new distributed generation that can efficiently defer or reduce grid costs (where that would be the cheapest way to achieve the required level of transmission service).
- 3.13 The Code amendment will leave Transpower responsible for identifying which distributed generation are required to meet the Grid Reliability Standards. This is appropriate because Transpower is best able to make this assessment.
- 3.14 For existing distributed generation, Transpower may not have the right incentives to carry out this task correctly. As discussed above in chapter 2, it might have the incentive to either under-pay or over-pay ACOT.
- 3.15 To address this, the Authority has set out a test (based on the Grid Reliability Standards) that Transpower is required to follow in identifying distributed generation that can efficiently defer or reduce grid costs and will make the final decision on ACOT payments itself.
- 3.16 It is possible that the test for existing distributed generation is too generous. For example, there may be some areas where the long-run marginal cost of transmission is calculated as zero, but where distributed generation exists that does assist Transpower to meet the Grid Reliability Standards. It may not be appropriate that all distributed generation identified as “required to meet the Grid Reliability Standards” continues to be paid ACOT in future. Nevertheless, we think the Grid Reliability Standards test will improve efficiency significantly. We will review the new ACOT arrangements no later than five years after the new arrangements have commenced for each region with the objective of further improving their effectiveness.
- 3.17 These changes will address the ACOT issue and promote efficiency, for reasons described in the next section.

**Amending the Code so ACOT is paid only to distributed generation that is required to meet the Grid Reliability Standards will promote efficiency**

- 3.18 The Code amendment will promote the Authority's statutory objective, for the reasons set out below.
- 3.19 The Code does not currently promote efficient outcomes in this area because:
- (a) **Information is not available:** distributors and distributed generators do not have the best information and analytical tools to assess how distributed generation affects transmission costs. Transpower is the best party to do that.
- (b) **The incentives are wrong:** a distributor's incentive will (at best) be to minimise transmission charges, rather than transmission costs. This is because the DGPPs encourage the reduction of transmission charges (rather than costs).
- (c) **The default provisions are inappropriate:** the regulated terms are typically interpreted as requiring distributed generators on the default terms to receive a credit based on the avoided transmission charges (ie, the avoided charge) rather than the avoided actual resource cost. There is typically no assessment of the real impact of distributed generation on transmission costs.
- 3.20 Efficiency requires that investors and owners of distributed generators face an incentive to provide transmission network (grid) support services (ie, to invest in or operate distributed generators so as to allow Transpower to efficiently defer or reduce grid

costs). In principle, such an incentive could potentially be provided through a market price, a transmission network charge or a side-payment (such as an ACOT payment).

- 3.21 Under the Code amendment, Transpower will identify the existing distributed generation that is required to meet the Grid Reliability Standards. Those that are not required to meet the Grid Reliability Standards can be assumed not to efficiently defer or reduce grid costs. For existing distributed generation, the Authority will review Transpower's advice before making the final decision on eligibility for ACOT payments under the regulated terms.
- 3.22 For new distributed generation, Transpower has incentives to contract for the provision of transmission-substitute services, where it is efficient to do so.
- 3.23 Transpower could still, at any time, decide to contract separately with a distributed generator (or another party) if it decided that to do so would reduce transmission costs (even if the distributed generator was not required to meet the Grid Reliability Standards). This would be broadly consistent with Transpower's incentives under the Commerce Act regime.

**Distributors will make ACOT payments under regulated terms only where distributed generation provides a transmission benefit**

- 3.24 This subsection sets out how the proposed Code amendment will reduce the extent to which distributors will be required to make inefficient ACOT payments.
- 3.25 The current DGPPs are typically interpreted as requiring distributors on the regulated terms to assess how the distributed generation on their network affects transmission *charges*. If distributed generation reduces transmission charges, the distributor must pay the distributed generator. If the distributed generation increases transmission charges, payment flows in the other direction.
- 3.26 Under the current TPM, distributed generators do not generally make transmission-related payments to distributors, because distributed generation does not increase the transmission charges the distributor pays.<sup>25</sup> Instead, distributors pay distributed generators in the form of ACOT payments.
- 3.27 The Code amendment will reduce ACOT payments in several different ways:<sup>26</sup>
- (a) Where the regulated terms apply, avoided transmission costs or charges will not be included in the calculation of payments between distributors and distributed generators unless the Authority has decided that the distributed generation is able to receive ACOT payments under the regulated terms.
  - (b) Where the regulated terms do not apply, the proposal could still have its intended effect, as it could influence the terms of future connection contracts agreed between distributors and distributed generators. This is because the Authority anticipates that parties will tend to align such contracts with the DGPPs, if the

<sup>25</sup> It is possible that a South Island distributed generator could cause its distributor to incur a HVDC charge that exceeded the reduction that the distributed generation brought about in the distributor's interconnection charge – although this situation is unlikely under the new MWh allocator of the HVDC charge (which is to be used to set transmission prices to apply from 1 April 2017). In this situation, there might be a case for the distributed generation to make ACOT payments to the distributor.

<sup>26</sup> In this context, and for the balance of this section, 'ACOT payments' includes payments to distributed generation.



DGPPs were to continue to exist. Further, some existing contracts may reference the DGPPs so that changes in the default terms trigger changes in the contract.

- (c) Distributors subject to price-quality control will not be able to recover the cost of ACOT payments from their customers unless the Authority has decided that the distributed generation is able to receive ACOT payments under the regulated terms. Distributors subject to price-quality control can recover ACOT payments under the Commerce Commission's current price-quality control arrangements (which run until 31 March 2020). The Code amendment removes this ability for distributed generation that the Authority has decided should not receive ACOT payments under the regulated terms because the 'distributed generation allowance' means they can only recover amounts payable or receivable 'made in accordance with (a) Schedule 6.4 of Part 6 of the Code (ie, the DGPPs), or (b) the Electricity Industry Act 2010'. ACOT payments made to distributed generation that the Authority has decided should not receive ACOT payments under the regulated terms will no longer be in accordance with the DGPPs. The Authority anticipates that if distributors could not recover the cost of making such ACOT payments they will stop making such ACOT payments, if their contracts allowed them to.
- 3.28 The Authority understands that distributors that are subject to price-quality control currently pay around 80% of ACOT (by value).
- 3.29 If distributors stop making ACOT payments to owners of distributed generation that do not efficiently defer or reduce grid costs this will be an efficient outcome. However, distributed generation should still be:
- (a) paid for the transmission services they provide
  - (b) charged for the transmission services they use.

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

- 3.30 This subsection sets out how distributed generators could still be paid for the benefits they provide (and pay for the costs they create), even if they do not receive ACOT payments from distributors (in cases where the distributed generator does not efficiently defer or reduce grid costs).
- 3.31 Table 3:
- (a) sets out services that distributed generators can provide, and how they could be paid for the services, under the Code amendment
  - (b) sets out services that distributed generators may require, and how they could pay for the services, under the Code amendment.
- 3.32 Table 3 is not restricted to *network* services; it also includes other types of services associated with distributed generation, such as export and sale of energy. However, the connection contract between the distributor and owner of distributed generation is not the correct vehicle to recover benefits and costs of non-network services.
- 3.33 Some effects of distributed generation, which some parties say are beneficial, are not included in the table because the Authority does not consider they are true economic benefits. These include:
- (a) reducing wholesale prices at system peak times
  - (b) reducing wholesale prices in the local area by mitigating transmission constraints.



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

**Table 3: Services that distributed generation can provide, and services that distributed generation can require**

Type of service	How the benefit or cost of service could be passed on to the distributed generation owner
Network services	
Avoided cost of transmission	Distributed generation that efficiently avoids grid costs will continue to receive ACOT payments from distributors.
Connection	Distributors could still recover from distributed generation owners the costs incurred by the distributor for the initial connection of distributed generation to their network.
Avoided cost of distribution	Where applicable, distributors could still make ACOD payments to distributed generation owners where the operation of the distributed generation reduced distribution network costs, and vice versa.
Improved local reliability of supply – eg, distributed generation can allow supply to be maintained during a planned or unplanned local network outage	Distributors subject to price control under the Commerce Act must meet a defined reliability standard to avoid a potential liability for breaches. They will continue to have an incentive to use/contract with distributed generation owners to promote attainment of these standards, where distributed generation offers the most efficient solution. For distributors not subject to price control under the Commerce Act, the alignment between distributor, customer, and owner interests is intended to ensure that distributed generation will be used/contracted with, where distributed generation provides the least cost means to attain the desired level of reliability.
Non-network services	
Providing energy	Distributed generation owners receive payment for their energy production, either directly through the wholesale electricity market or indirectly via a contract outside the wholesale market.
Intermittency	The wholesale electricity market should signal the cost of intermittency.
Providing capacity, and hence supporting reliability, at peak times	To the extent that distributed generation provides capacity at peak times, it should be able to obtain a reward through the wholesale electricity market (as spot market prices are often higher at peak times) or through a contract.

Type of service	How the benefit or cost of service could be passed on to the distributed generation owner
Reducing the costs associated with congestion by mitigating local transmission constraints	To the extent that distributed generation mitigates local transmission constraints, it should be able to obtain a reward through the wholesale electricity market.
Providing ancillary services	Ancillary service markets are intended to deliver the appropriate incentives for provision of ancillary services.
Altering network losses	<p>The price paid to generators for their energy production generally reflects marginal losses.</p> <p>However, neither grid-connected generators nor owners of distributed generation:</p> <ul style="list-style-type: none"> <li>• receive payment for loss reduction, where their operation reduces the overall cost of network losses (relative to a counterfactual in which they do not operate)</li> <li>• pay for increasing losses, where their operation increases the overall cost of network losses (relative to a counterfactual in which they do not operate).</li> </ul>
Retail market competition benefits – ie, distributed generation investment in a region subject to locational price risk, by a party other than the main generator in that region, can support more retailers to compete in the local retail market	<p>Such distributed generation investment can be incentivised:</p> <ul style="list-style-type: none"> <li>• through the retail market, if the distributed generation investor is also a retailer that wishes to compete in the region, or</li> <li>• through the contract market, otherwise.</li> </ul>

3.35 Table 4 sets out services that distributed generators may provide that relate to matters outside the Authority's statutory objective. These effects are included because they are relevant considerations for other policy makers and stakeholders. Table 4 also sets out how owners of distributed generation could be incentivised to provide such services, if distributors stop making ACOT payments.

**Table 4: Services that distributed generation can provide relating to matters outside the Authority's statutory objective**

Type of service	How the benefit or cost of service could be passed on to the distributed generation owner
Reducing greenhouse emissions	The Emissions Trading Scheme is the primary mechanism designed to incentivise generators to reduce greenhouse emissions.

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

3.36 The Authority has concluded that, even where ACOT payments are no longer made between distributors and distributed generation owners, distributed generation owners could still:

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

**A phased transition allows time for Transpower to carry out the required analysis and make recommendations to the Authority**

3.37 The Code amendment will take effect on:

- (a) 1 April 2018 for distributed generation located in the LSI transmission region (previously 1 April 2017)
- (b) 1 October 2018 for distributed generation located in the LNI transmission region (previously 1 April 2017)
- (c) 1 April 2019 for distributed generation located in the UNI transmission region (previously 1 April 2018)
- (d) 1 October 2019 for distributed generation located in the USI transmission region<sup>27</sup> (previously 1 April 2018).

3.38 The phasing uses the regions Transpower has used for transmission charging purposes.

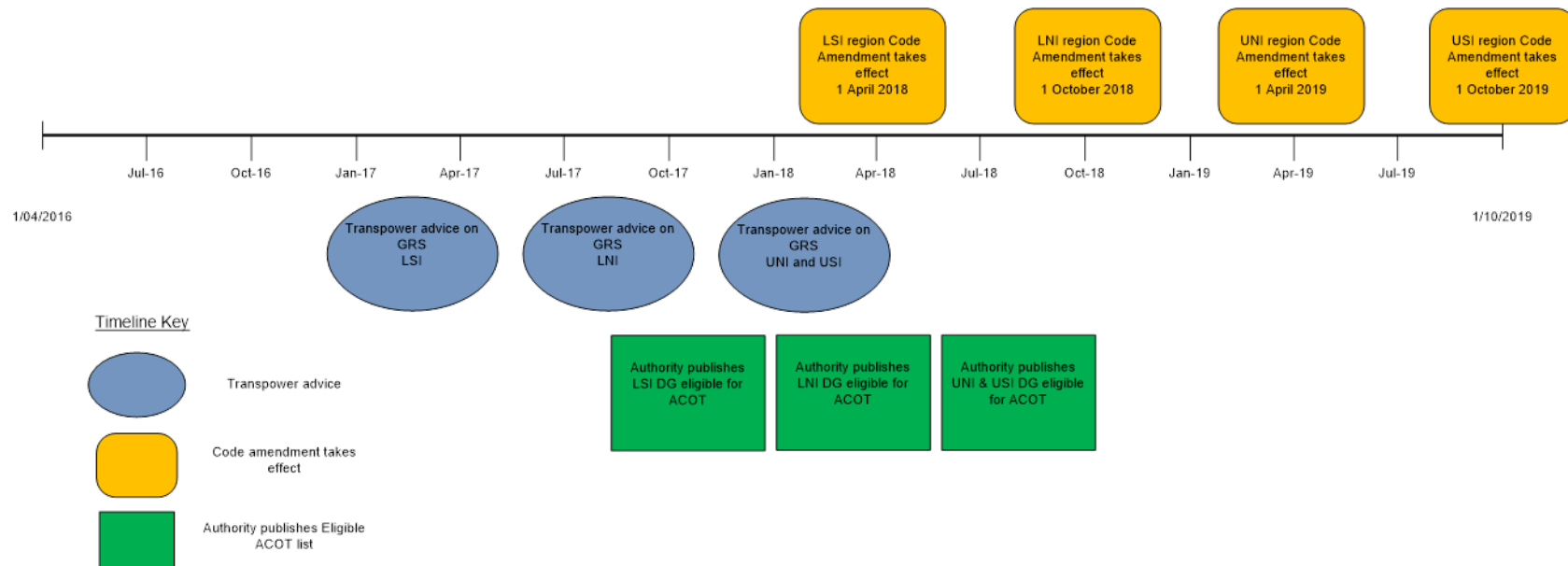
<sup>27</sup> These four transmission pricing regions were defined for transmission pricing purposes in 2006. [https://www.transpower.co.nz/sites/default/files/uncontrolled\\_docs/TPM\\_2006\\_%20Supplementary\\_Material.pdf](https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/TPM_2006_%20Supplementary_Material.pdf)

- 3.39 The Authority considered bringing the Code amendment into force for all regions on 1 April 2018. This may not be workable because Transpower needs enough time to analyse avoided transmission benefits of existing distributed generation and identify those distributed generation that can efficiently defer or reduce grid costs.
- 3.40 Other options the Authority considered were:
- (a) starting with larger distributed generation plants (by MW)
  - (b) starting with those distributed generators who receive larger ACOT payments.
- 3.41 However, neither a transition process based on MW capacity nor one based on size of ACOT payment would deliver the net benefits of the new arrangements because:
- (a) If the changes to the Code affected larger distributed generators (mainly hydro, geothermal and wind) first, many small- to mid-size thermal distributed generation plants might operate out of merit order.
  - (b) Larger distributed generators (which receive larger ACOT payments) are spread across all four regions. Transpower would need to analyse payments for all regions in all phases of the transition, leading to higher transaction costs. This is because the need for transmission network support must be analysed at the level of an area or region, not at the level of an individual distributed generator.
- 3.42 We think the transition approach we have decided on has the following advantages:
- (a) Transaction costs. Transpower is likely to analyse avoided transmission benefits for distributed generation for each region. Transpower's transaction costs will be lower, as it can carry out this analysis for one region at a time. This phased approach to implementation will keep Transpower's task at a manageable size initially, before ramping up.
  - (b) Benefits. The timing of the transition needs to strike a balance between delivering benefits promptly and allowing enough time for participants to transition to the new regime. The earlier the implementation, the sooner it will deliver the full benefits of the new ACOT payment regime. By getting the implementation process underway the approach allows the net benefits of the new ACOT payment regime to begin to flow to consumers as soon as possible.
  - (c) Risks. We had originally proposed to include the LNI region in the first tranche, together with the LSI region. However, we have decided that there are important differences between these two regions. The LSI is the region considered least vulnerable to grid reliability problems. It also has fewer distributed generators than the LNI region. Beginning with the LSI is a measured approach that will reduce any risk associated with the Code amendment. Transmission charging arrangements have historically provided muted signals for controlling peak demand in the LSI, indicating that this region is typically not import-constrained.
- 3.43 The phasing also recognises that:
- (a) distributed generation located in the UNI region are more likely to deliver avoided transmission benefits than those in the LSI or LNI (but less likely than the USI)
  - (b) potential reliability risks in the UNI region are higher than in the LSI or LNI (but lower than in the USI).

The Authority had previously considered that for practical reasons, all phases in the transition should take effect at the start of a financial year (ie, 1 April). However, we now understand that an October implementation date would also be manageable.

3.44 Figure 3 sets out the proposed timeframe for the suggested region-based transition.

**Figure 3: Timeframe for transition**





- 3.45 The Authority considers that this transition is achievable and will deliver net benefits early in the transition period and minimise risks.

### **Stakeholders raised a number of issues relevant to the Code amendment**

- 3.46 Submitters raised a number of issues with the proposal to remove the DGPPs. Many of these issues are also relevant to the Code amendment we have now decided to make. In the remainder of this section we discuss some of the main issues raised by submitters and the Authority's responses.
- 3.47 Submitters also raised some issues that relate to matters outside the Authority's jurisdiction. These are briefly discussed at the end of this chapter.

### **Transpower may not have the right incentives**

#### **Submitters' views**

- 3.48 Some parties submitted that under the May 2016 proposal, Transpower may not have the right incentives to make ACOT payments at the efficient level. These arguments may also apply, to some extent, to the Code amendment. For example, Axiom (on behalf of Transpower) observed that network solutions are generally – and often quite reasonably – perceived by network service providers as having lower risks and lower transaction costs. Some parties said that distributed generation effectively "competes" with Transpower in the long run, and Transpower would be disinclined to support a competitor.
- 3.49 The result could be that Transpower would fail to identify distributed generation that can defer or reduce grid costs in circumstances where distributed generation would be the most efficient solution.

#### **The Authority's decision**

- 3.50 After considering submissions, the Authority's view is that there are some uncertainties in this area. The uncertainties are greatest in the case of existing distributed generation that provides a transmission benefit. To the extent that its costs are sunk, the distributed generator may face an imbalance of bargaining power with Transpower – depending on the alternatives available to Transpower. Each party will face information uncertainties, and transactions costs to obtain better information.
- 3.51 As a result, Transpower might respond to the incentives noted above by failing to recommend ACOT payments be made to existing distributed generation in circumstances where it would be efficient to do so. These outcomes would undermine the efficiency benefits of the proposal, and might also affect reliability, at least in the short term.
- 3.52 Alternatively, if Transpower recommended that ACOT payments be made to distributed generation that cannot efficiently defer or reduce grid costs, this approach would fail to capture the efficiencies that the Authority intends the Code amendment to produce.
- 3.53 To address these issues, the Authority has decided to introduce as part of this Code amendment a test that Transpower must apply, based on the Grid Reliability Standards. Further, the Authority has decided that it will make the final decision on which existing distributed generators will be paid ACOT (based on Transpower's advice).

- 3.54 Introducing a test for Transpower to apply and introducing oversight from the Authority ensures the efficiency benefits of the Code amendment will be realised in respect of existing distributed generation.
- 3.55 The Code amendment leaves Transpower solely responsible for determining the need for any additional grid support services from new distributed generation. Transpower has the best information, ability and incentives to assess the value of those services. The Commerce Act 1986 provides incentives for Transpower to provide a defined level of transmission service at the lowest possible cost. Prospective investors in new distributed generation have other options available for their investment. Their investment is not yet sunk, so the bargaining power issue noted above for existing distributed generation does not arise. Further, Transpower's incentives are changing, due to emerging technologies (which raise the possibility that new transmission assets will be stranded some time in their life, and so give Transpower an incentive to favour non-transmission solutions). As a result, the Authority expects that Transpower will enter into agreements with owners of new distributed generation whose operation could efficiently reduce or defer transmission network costs.

### **Concerns about reliability of supply are unfounded**

#### **Submitters' views**

- 3.56 Some submitters argued that the DGPP proposal would reduce reliability (as the result of closures of distributed generation financially impacted by the proposal and also distributed generation not operating at peak due to not receiving ACOT). For example, Pioneer Energy suggested that distributed generation sources will enhance reliability.<sup>28</sup>
- 3.57 These arguments could also apply (although perhaps to a lesser extent) to the Code amendment, due to its effect on ACOT payments.

#### **The Authority's decision**

- 3.58 The Authority considers that the Code amendment will not reduce reliability levels, for the following reasons (which are discussed in more detail in Appendix C).
- 3.59 First, as regards the reliability of generation operation, nodal price signals in the wholesale energy market will continue to provide incentives for generators to operate during tight supply periods.
- 3.60 Second, as regards transmission network reliability, distributed generation that is required to meet the Grid Reliability Standards will continue to receive ACOT payments, so their reliability benefits will be preserved. Further, Transpower is not precluded from negotiating with distributed generation or any other party if action is required to prevent reliability issues.<sup>29</sup>
- 3.61 Third, distributed generation is not inherently more reliable than other forms of generation when it comes to meeting peak demand requirements. In fact, while distributed generation represents up to 25% of all generation at off-peak times, this proportion *falls* to less than 15% at peak times.<sup>30</sup>

<sup>28</sup> Pioneer Energy, *RE: Transmission Pricing and Distributed Generation Policy Submissions*, submission to Electricity Authority, 26 July 2016, paragraphs 3.67 – 3.70.

<sup>29</sup> Transpower is permitted to utilise transmission substitutes, including distributed generation, where it wishes, provided it can still meet its defined service standard.

<sup>30</sup> Source: Electricity Authority analysis, based on data for the year beginning October 2015.

- 3.62 Fourth, the Code amendment (which affects ACOT) will have a substantially reduced financial risk for distributed generation than the May 2016 DGPP proposal (which would also have removed the regulated price ceiling on distribution charges). So the possible closures of distributed generation that some submitters are concerned about are less likely to occur under the Code amendment than under the May 2016 DGPP proposal. Any impact on reliability will accordingly be reduced.
- 3.63 Finally, analysis commissioned by the Authority (and set out at Appendix D) finds that while the Code amendment (and the Authority's TPM proposals) could have some impact on the ability to meet peak electricity demand, these changes are unlikely to reduce the Winter Capacity Margin below efficient levels.<sup>31</sup>

### **The Code amendment will not cause any permanent change in wholesale electricity prices**

#### **Submitters' views**

- 3.64 Some submitters have suggested that the DGPP proposals will increase electricity prices to consumers (due to closures of distributed generation financially impacted by the proposal and due to distributed generation not operating at peak due to not receiving ACOT). These arguments could also apply (although perhaps to a lesser extent) to the Code amendment, due to its effect on ACOT payments.

#### **The Authority's decision**

- 3.65 The Authority considers that the Code amendment will not give rise to any costs in this area, for the following reasons.
- 3.66 Distributed generation owners will still be incentivised to efficiently provide energy into the wholesale market, as they receive payment for their energy production, either directly or through the wholesale electricity market.
- 3.67 Distributed generation could be crowding out other competing generators and competing emerging technologies. There is a possibility that some planned investment in distributed generation does not go ahead as a result of the Code amendment. However, countering this effect, the reduction or removal of ACOT payments may encourage new generation investment in grid-connected generation, or the retention of existing grid-connected generation. Therefore, it is not clear that reducing or removing ACOT payments will lead to a reduction in the total amount of generation available. Even if there was a minor short-term decline, it is likely that decline would be reversed in time.
- 3.68 In any case, the Authority does not consider that it is in the long-term benefit of consumers to subsidise generators to enter the market.

### **The Code amendment will not harm retail market competition**

#### **Submitters' views**

- 3.69 Some submitters argued that the proposal would reduce retail market competition. One submitter said that independent generation plays an important role in supporting entry and participation in the market by independent electricity retailers. They said the

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<sup>31</sup> The Winter Capacity Margin is a measure of the ability to serve demand during short periods of system tightness, such as peak demand periods and/or when an unexpected loss of major generation/transmission capacity occurs. See Concept Consulting Group, *Winter capacity margin— potential effect of recent transmission pricing and distributed generation proposals*, November 2016.

proposal would reduce the viability of such retailers (by reducing the viability of independent generators) and so would reduce competitive tension in the market.

### **The Authority's decision**

- 3.70 The Authority does not consider that the Code amendment will negatively impact retail market competition.
- 3.71 Our view is that the Code amendment won't cause a substantial number of distributed generators to shut down. Most distributed generation has very low operating costs (as most are wind or hydro generators). Revenue from producing electricity will be more than enough to cover those low operating costs. The only possible exception would be a relatively small number of high-fuel-cost (diesel) generators, if they don't defer or reduce grid costs (and so don't receive ACOT payments in future). Even if some of these diesel generators do close, it won't impact on the viability of independent electricity retailers, given they represent only a small proportion of total distributed generation.
- 3.72 Further, the Code amendment reduces financial risk for distributed generators (compared to the Authority's May 2016 DGPPs proposal) because we are no longer proposing to remove the regulated price ceiling on distribution charges. This change reduces the impact of the proposal on distributed generators by more than 50% (based on analysis carried out by PWC for the IEGA).<sup>32</sup>
- 3.73 Further, the Authority does not consider that subsidising distributed generators is an appropriate way to support competition. There are better ways to further the objective of promoting competition in the market. We are facilitating a number of initiatives that will enhance the operation of the hedge market for electricity (including the introduction of financial derivative cap products and a project intended to further enhance Financial Transmission Rights products). These initiatives will assist participants to efficiently manage risk and so will support entry and participation in the market by independent electricity retailers.

## **The Code amendment will not affect voltage support and losses**

### **Submitters' views**

- 3.74 Some submitters argued that distributed generation provide additional benefits in terms of voltage support and losses. These arguments could also apply (although perhaps to a lesser extent) to the Code amendment, due to its effect on ACOT payments.

### **The Authority's decision**

- 3.75 The Authority considers that the benefits that distributed generation provide in the area of voltage support and losses will not be affected by the proposal and will continue to be provided, for the following reasons:
- (a) Although distributed generation can reduce transmission and distribution losses, the most significant of these are grid losses.

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<sup>32</sup> PWC estimated the indicative value impact for the distributed generators in its study of both (A) losing ACOT revenue and also (B) being required to contribute to common costs through distribution charges. Based on this analysis, dropping the proposal to remove the regulated price ceiling reduces the impact of the proposal on distributed generators in the study by between 56% and 72%, depending on assumptions about the amount of the contribution to common costs. Of course, the financial impact of the Code amendment will reduce to zero for those distributed generators that contribute to grid reliability and so will continue to receive ACOT payments under the Code amendment.

- (b) The location-specific wholesale market prices received by generators (including distributed generators that directly or indirectly receive market price signals) already take into account marginal grid losses.
- (c) This price signal, which contributes to generators making an efficient location decision, will not be affected by the Code amendment.
- (d) However, neither distributed generation nor grid-connected generators receive payment for loss reduction or pay for increasing losses (where their operation has that effect).
- (e) Voltage support is one of the network support services that distributed generation may provide to Transpower (and so could continue to receive ACOT under the proposal) or to distributors (and so be paid for it via ACOD payments.)

**The best way to promote regulatory certainty and dynamic efficiency is to be predictable and consistently follow the statutory objective**

**Submitters' views**

- 3.76 Some submitters have argued that the proposed DGPP changes will undermine dynamic efficiency because they represent an unanticipated change to a settled set of arrangements.
- 3.77 In support of this view, submitters have cited a range of arguments which can be summarised as:
- (a) Remuneration of distributed generation based on avoided transmission charges is a long-standing feature of the regulated environment for electricity, dating back to use of bulk supply tariffs.
  - (b) A Ministerial Inquiry into the electricity industry was conducted in 2000, and it recommended the use of arrangements akin to the DGPPs.
  - (c) The recommendations from the Ministerial Inquiry were codified as Electricity Governance (Connection of Distributed Generation) Regulations in 2007. The DGPPs, which replaced the regulations from December 2010, have the same substantive provisions for ACOT payments.
  - (d) Investors in distributed generation have relied on an expectation that the arrangements reflected in the DGPPs would continue to allow a reasonable period for capital recovery.
- 3.78 These arguments could also apply (although perhaps to a lesser extent) to the Code amendment, due to its effect on ACOT payments.

**The Authority's decision**

- 3.79 The Authority considers that the best way to promote regulatory certainty and the right climate for investment in the long-term is for the Authority to consistently pursue its statutory objective.
- 3.80 The Authority does not consider that the Code amendment will give rise to dynamic efficiency losses. The principal reasons are:
- (a) There has been no long-standing historical regulatory policy for distributors to make ACOT payments to distributed generation on the basis of avoided

transmission charges – rather any such payments have been a matter of custom or contract.

- (b) In more recent times, the distributed generation regulations (and DGPPs) set regulated terms available for new distributed generation since August 2007. However, distributed generation investors could not reasonably expect the assured future continuation of the present arrangements given their adverse efficiency effects.
  - (c) Requiring the retention of inefficient ACOT payments going forward would create adverse incentives, and would not be in the long-term interest of consumers
  - (d) The Code amendment may have potentially offsetting dynamic efficiency effects that would reduce the cost of capital, as it will enable a forward-looking investor to be more confident the Authority won't apply a "grandfathering" policy in future when dealing with other contentious issues.
- 3.81 Indeed, the Code amendment will promote dynamic efficiency, because it demonstrates that the Authority will pursue changes where they promote the statutory objective.
- 3.82 A more detailed discussion of these issues is set out at Appendix C.

### **The Code amendment will not cause any net increase in transaction costs**

#### **Submitters' views**

- 3.83 Implementation of the DGPP proposals is expected to result in increased transaction costs in some areas. In particular, higher costs might arise from:
- (a) additional negotiations between Transpower and distributed generation owners regarding transmission substitution services
  - (b) additional negotiations between distributors and distributed generation owners regarding distribution substitution services.
- 3.84 Some submitters have suggested that the increase in transaction costs will be substantial.<sup>33</sup> These arguments appear to apply to the May 2016 proposal. However, we have also considered whether they could also apply (albeit to a lesser extent) to the Code amendment.

#### **The Authority's decision**

- 3.85 The Authority considers that overall transaction costs are unlikely to materially increase in present value terms under the Code amendment.
- 3.86 We have made refinements in our Code amendment that we expect to reduce transaction costs relative to the proposal in the May 2016 consultation paper, including:
- (a) the Authority has decided not to remove the DGPPs entirely from Part 6 of the Code at this stage
  - (b) under the Code amendment there will be no requirement for negotiations between Transpower and existing distributed generation owners.
- 3.87 We also expect that there will be transaction cost savings for some distributors and distributed generation owners from the Code amendment.

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<sup>33</sup> See for example Creative Energy Consulting Pty Ltd, *Review of the Electricity Authority's DGPP Consultation Paper*, July 2016, page 16.



3.88 These matters are discussed further in Appendix C.

### **The Authority has extended the timeframe for implementation**

#### **Submitters' views**

3.89 Some submitters argued that the timetable outlined in the May 2016 consultation paper did not allow sufficient time for the proposal to be implemented. For example, Transpower submitted that it could not establish the planning, economic, commercial or legal frameworks to support the new regime before 1 April 2017.

#### **The Authority's decision**

- 3.90 The Authority considers that some valid concerns have been raised in submissions on the feasibility of the original timetable (ie April 2017 implementation). Retaining the existing timetable raises a number of risks (for example, distributed generators that reduce grid costs might not be paid).
- 3.91 After considering submissions, we have decided to delay implementation (compared with the proposal). The new timetable retains a phased approach, but spreads out implementation over four phases instead of two.
- 3.92 The phased approach will:
- (a) keep Transpower's task at a manageable size in the first year, before ramping up in the following year
  - (b) allow the net benefits of the new ACOT payment regime to begin to flow to consumers as soon as possible
  - (c) reduce any risk associated with the Code amendment.
- 3.93 The new timetable will allow additional time for Transpower to analyse its grid support requirements, and identify distributed generation that efficiently avoids grid costs. It allows more time in the USI and UNI regions, where more distributed generation are likely to be able to efficiently defer or reduce grid costs, relative to the LSI and LNI. It also allows more time in the LNI region, where more distributed generation is located, relative to the LSI region.

### **Transpower has sufficient resources to assess the ability of distributed generation to efficiently defer or reduce grid costs**

#### **Submitters' views**

3.94 Some submitters argued that Transpower is not sufficiently resourced for the responsibilities the Authority is proposing it take on. Most of these arguments apply only to the original proposal in the consultation paper, although some of them may also be relevant to the Code amendment.

#### **The Authority's decision**

- 3.95 The Authority considers that Transpower has sufficient resources to assess which distributed generation are required to meet the Grid Reliability Standards, as required by the Code amendment.
- 3.96 Transpower knows the transmission network well, and is required to be aware of the extent of the network's dependency on distributed generation. Transpower regularly prepares reports on its ability to meet the Grid Reliability Standards.

- 3.97 Transpower will also have gained understanding of the ability of both distributed generation and demand response to efficiently defer or reduce grid costs through the operation of its Demand Response (DR) programme. The DR programme covers both demand that can be directly managed and reductions in net demand via use of controllable distributed generation.
- 3.98 While Transpower will be responsible for assessing any requirements for grid support from new distributed generation investments, we don't expect this to result in a major additional burden on Transpower. The number of new distributed generation investments in the five-year period after the new arrangements have commenced for each region is likely to be relatively small compared to the number of existing distributed generators. Transpower has experience at assessing the ability of distributed generation to defer transmission investment. For example, Transpower considered non-transmission solutions as alternatives to its North Island Grid Upgrade (NIGU) investment in its October 2006 proposal. The non-transmission solutions considered included use of distributed generation to defer the transmission investment (specifically, diesel-fired peaking generators).

### **We have taken into account contractual requirements to keep paying ACOT**

#### **Submitters' views**

- 3.99 Some submitters raised the issue that some distributors will be contractually required to continue making ACOT payments to owners of distributed generation after the Code change takes place, but would be unable to pass these costs on under the Commerce Commission's regime. Unison said this potentially exposes distributors to a financial risk. These arguments would also apply to the Code amendment.

#### **The Authority's decision**

- 3.100 The Authority is aware that the Code amendment may affect some existing contracts that reference the default terms through 'change in law' provisions. However, at the time such contracts were entered into, the two parties made an assessment about how they would address any changes in the regulatory environment (if at all). The Authority is not proposing to alter any such provisions.
- 3.101 Other existing contracts may be written in such a way that ACOT payments to distributed generation will continue until the contract expires, despite the Code amendment. The Authority must consider the effects of the continuation of some ACOT payments on the net benefits of the proposal. The benefits of the Code amendment will be lower to the extent that inefficient ACOT payments continue. The cost-benefit analysis takes this into account. It assumes that the Code amendment will result in a reduction in the inefficient operation of distributed generation of between 60% and 90%, based on the Authority's view of the probability that ACOT payment terms in existing contracts reference the DGPPs.

### **Issues raised in submissions that are of interest to other policy-makers**

- 3.102 The following table sets out arguments made in submissions that relate to matters outside the Authority's statutory objective. These effects are included because they are relevant considerations for other policy makers and stakeholders. These arguments could also apply (although perhaps to a lesser extent) to the Code amendment, due to its effect on ACOT payments.



Issue	Response
<p>Some submitters have suggested that the DGPP proposals will increase greenhouse gas emissions, or cause other environmental costs.</p>	<ul style="list-style-type: none"> <li>• Not a relevant factor – outside Authority’s mandate.</li> <li>• In any case, the Code amendment will not give rise to any costs in this area: <ul style="list-style-type: none"> <li>○ There are other policy instruments that address these matters, including a carbon pricing regime and various environmental statutes and regulations. These apply equally to distributed generation and grid-connected generation.</li> <li>○ New Zealand's grid-connected generation is largely renewable. In recent years, new grid-connected generation has largely been in the form of wind and geothermal power stations.</li> <li>○ Generation entering the market in future is expected to be overwhelmingly (95%) renewable.</li> </ul> </li> </ul>
<p>Impact on regional communities</p>	<ul style="list-style-type: none"> <li>• Not a relevant factor – regional impacts are outside Authority’s mandate.</li> <li>• In any case, we disagree, as: <ul style="list-style-type: none"> <li>○ most grid-connected generators are located in the regions, and employ people in these regions.</li> <li>○ distributed generation will continue to locate in and operate in regional areas of New Zealand to the extent that it is efficient for them to do so.</li> <li>○ Due to the low operating cost of most distributed generation, it is unlikely that many (if any) distributed generation would shut down if ACOT payments were reduced</li> <li>○ distributed generation owners will still be incentivised to provide local economic benefits, as these may yield branding advantages and help distributed generation to forge constructive relationships with communities.</li> </ul> </li> </ul>
<p>Proposal will have a negative</p>	<ul style="list-style-type: none"> <li>• Not a relevant factor – wealth transfers are</li> </ul>

<b>Issue</b>	<b>Response</b>
impact on distributed generation	outside Authority's mandate.

## 4 Removing the DGPPs now might not promote the long-term benefit of consumers

### **Addressing the connection services problem in the way proposed might not promote the Authority's statutory objective**

- 4.1 After considering issues raised in submissions, we have formed the view that the proposed Code amendment to remove the DGPPs from the Code might not promote the Authority's statutory objective at this stage.
- 4.2 Submitters said the proposal could allow distributors to use their monopoly power to overcharge distributed generation for connection services. As a result, the proposal could fail to ensure competitive neutrality between distributed generation and grid-connected generators. These concerns are discussed in more detail later in this chapter under the heading "Stakeholders raised three key issues relating specifically to the connection services issue".
- 4.3 We think these concerns are potentially valid. After considering submissions, at this stage we think the proposal to remove the DGPPs might have negative effects on efficiency and reliability.

### **The benefits of addressing the connection services problem now might not exceed the costs**

- 4.4 The qualitative analysis for the May 2016 proposal showed benefits were likely.
- 4.5 However, the May 2016 proposal did not take into account the negative effects on efficiency and reliability that have been identified in submissions as potential results of the two issues discussed above (distributor monopoly power and generation competitive neutrality).
- 4.6 We have not quantified these potential negative effects. However, it is possible they may be significant.
- 4.7 Once these potential results are taken into account, the expected net economic benefit of the proposal to remove the DGPPs might no longer be positive.
- 4.8 So we have decided not to proceed with the proposal to remove the DGPPs at this time.

### **Stakeholders raised three key issues relating specifically to the connection services issue**

- 4.9 Submitters had three main concerns specific to the connection services issue. They said the proposal would have:
- (a) allowed distributors to use their monopoly power to overcharge for connection services
  - (b) exacerbated the risk that distributors underpay ACOD
  - (c) undermined competitive neutrality.
- 4.10 (Note that submitters also raised a number of objections that apply to the ACOT issue alone, or to the ACOT issue as well as the connection services issue. They are dealt with earlier in this paper under the heading Stakeholders raised a number of issues relevant to the Code amendment.)

- 4.11 After considering these issues, we have formed the view that the proposed Code amendment to remove the DGPPs from the Code might not promote the Authority's statutory objective. We now think the proposal to remove the DGPPs has the potential to have negative effects on efficiency and reliability.

### **The proposal would have allowed distributors to use their monopoly power to overcharge for connection services**

#### **Submitters' views**

- 4.12 Some submitters said that in removing the regulated price ceiling, the proposal would allow distributors to overcharge distributed generation for connection services. Allan Carvell (in a report for Trustpower) said "Without constraints, a distributor may set prices for connection services to distributed generation that sit higher in the subsidy free range than is economically efficient.... Prices at or near the stand alone cost level likely will deter what might otherwise be economic investment in distributed generation."
- 4.13 Stakeholders also submitted that distributors would have the incentive to discriminate against distributed generation because they prefer network solutions over non-network alternatives and because they are in competition with distributed generation. For example, Creative Energy Consulting (on behalf of Trustpower) submitted that distributed generation is an important competitor to network business at both the transmission and distribution levels.
- 4.14 Some submitters argued that the distribution pricing principles are insufficient to control distributors' pricing of connection services to distributed generation. Submitters also noted that those distributors that are exempt from Part 4 of the Commerce Act 1986 face no regulatory constraint on their pricing of connection services to DGs.
- 4.15 One submitter (Allan Carvell on behalf of Trustpower) argued that the Commerce Commission's regulations under Part 4 of the Commerce Act 1986 don't control revenue that distributors earn from connection services to DGs. Mr Carvell's argument was based on an exclusion from the regulation set out at s.54C(2)(c) of Part 4 of the Commerce Act.

#### **The Authority's decision**

- 4.16 The Authority agrees that submitters have raised significant risks with the May 2016 proposal around distributors' monopoly pricing power. As a result, removing the DGPPs might have negative impacts on efficiency and reliability. We will consider this issue in other projects including the distribution pricing review. We have not yet completed these projects, so we cannot resolve the issue of distributors' monopoly pricing power immediately. In response to these risks (and other concerns) we have made a significant change to our proposal, ie, we have decided not to remove the DGPPs from the Code.
- 4.17 We don't agree with Allan Carvell's submission that Part 4 of the Commerce Act 1986 doesn't apply to revenue that distributors earn from connection services to DGs. Our understanding is that the exclusion set out at s.54C(2)(c) that Mr Carvell relies on refers to lines and/or equipment between the generation plant and the first piece of equipment owned by the distributor. That is, the section excludes the electricity lines owned by the generator. It follows that revenue that distributors earn from connection services to DGs comes within the scope of the weighted average price cap regime administered by the Commerce Commission.
- 4.18 Nevertheless, in the absence of the DGPPs, there is a risk that there would be insufficient constraints on distributors' pricing of connection services to DGs. Distributors'

pricing is not tightly regulated (as is Transpower's pricing, for example).<sup>34</sup> The distribution pricing principles are relatively high-level and are not mandatory. There is a risk that the distribution pricing principles – in their current form – might not appropriately constrain distributors' pricing to DGs. Moreover, it is possible that distributors may have incentives to discriminate against distributed generation (in favour of load), eg, where residential consumers own the distributor.

- 4.19 If distributors overcharge distributed generation for connection services, this could impose inefficiently high costs on distributed generation which would lead to productive inefficiency and undermine competition between distributed generation and grid connected generation.<sup>35</sup> There is a risk that in some cases this could lead distributed generation to shut down, or operate differently, reducing the total supply of generation at peak times. It is possible this could reduce reliability at peak times.<sup>36</sup>
- 4.20 In response to these risks (and other concerns) raised in submissions, the Authority has decided not to remove the DGPPs from the Code at this time.
- 4.21 The Authority is considering the issue of distributors' market power in other projects including the distribution pricing review. It is also a key issue in the default distribution agreement project (which applies to contracts between distributors and retailers) and potentially other projects too. We expect to develop solutions to the issue of distributors' market power in these other projects.

### **The proposal would have exacerbated the risk that distributors underpay ACOD**

#### **Submitters' views**

- 4.22 Some submitters argued that under the proposal distributors would fail to pay distributed generation for the avoided cost of distribution (ACOD) in circumstances where it would have been efficient to do so. Trustpower submitted that distributed generation provides network support to both distributors and Transpower, yet currently very little ACOD payments are made. Trustpower argued that this issue needs to be investigated before amending Schedule 6.4 as it is likely the current policy settings are inadequate.

#### **The Authority's decision**

- 4.23 The Authority considers that the May 2016 proposal could have exacerbated the risk that distributors would fail to pay distributed generation for the ACOD in circumstances where it would have been efficient to do so. This is a further reason why removing the DGPPs might have negative impacts on efficiency and reliability, and another factor in our decision not to remove the DGPPs from the Code.
- 4.24 Another consequence of distributors' monopoly pricing power (in addition to the risk of overcharging distribution charges to distributed generation described above) is that distributors might fail to contract with distributed generation for ACOD (or underpay for ACOD services provided). To the extent that distributors fail to pay ACOD, they might instead upgrade their network in circumstances where distributed generation would have been the more efficient alternative.

<sup>34</sup> Transpower is subject to a prescriptive regulated pricing methodology set out in the Code (ie, the TPM).

<sup>35</sup> This issue is discussed later in this chapter under the heading The proposal would have undermined competitive neutrality.

<sup>36</sup> Note that a separate issue concerning reliability (ie, reliability risks associated with the Code amendment) is discussed in chapter 3 under the heading Concerns about reliability of supply are unfounded.

- 4.25 The Authority's May 2016 proposal could have exacerbated this risk. The DGPPs currently provide for distributors to make ACOD payments to distributed generation owners, where distributed generation produces distribution network cost benefits. However, we had proposed to remove the DGPPs.
- 4.26 The Authority's decision not to remove the DGPPs from the Code at this time means that distributors will continue to be required to pay ACOD to distributed generation that avoid distribution costs. The Code amendment removes distributors' requirement to pay ACOT, but it does not affect their requirement to pay ACOD. So the Code amendment (unlike the May 2016 proposal) does not exacerbate the risk of underpayment of ACOD.
- 4.27 The question of whether ACOD is being underpaid under the existing DGPPs is a separate issue. It may be that, despite the existing requirement to pay ACOD, distributors are exercising their monopoly power to avoid engaging with distributed generation with respect to non-network solutions to distribution network issues. We do not yet have enough evidence to form a view on this question.
- 4.28 However, we do not need to determine whether or not ACOD is being underpaid under the existing DGPPs before making the Code amendment. That is because the Code amendment does not affect this issue (as the Code amendment relates to ACOT not ACOD). We will consider this issue at a later date. Given that this issue relates to distributors' monopoly power, we think it is appropriate to consider it together with other Authority projects related to distributors' monopoly power (eg, the distribution pricing principles review).

### **The proposal would have undermined competitive neutrality**

#### **Submitters' views**

- 4.29 Some stakeholders submitted that removing the regulated price ceiling on distribution charges would disadvantage distributed generation, compared to grid-connected generation. This is because distributed generation would be required to contribute to the common costs of the distribution network, while grid-connected generation would make a relatively low contribution to the common costs of the grid. Unison submitted that having different charging methodology for grid-connected generators as opposed to distributed generators would unfairly disadvantage distributed generators.
- 4.30 The Independent Electricity Generators Association argued that removing the regulated price ceiling could also disadvantage independent distributed generation compared with distributed generation located behind load and distributed generation owned by distributors.

#### **The Authority's decision**

- 4.31 After considering these submissions, the Authority's view is that removing the DGPPs may not ensure competitive neutrality between distributed generation and grid-connected generation (and other technologies). It will not be possible to resolve this issue until the reviews of TPM and distribution pricing have been progressed further. We have decided not to remove the DGPPs from the Code at this time. Instead, the Authority intends to address the connection services issue in a way that will ensure competitive neutrality between different technologies and modes of generation and demand response.
- 4.32 We would observe that grid-connected generation does make contributions to the common costs of the transmission network. South Island grid-connected generation

makes a contribution to transmission network common costs through their payment of HVDC charges under the existing TPM. And all grid-connected generation make a contribution to Transpower's overheads, through connection charges. Further, under the proposed TPM, grid-connected generation that benefits from transmission investments would pay AoB charges, which represent a contribution to transmission network costs that is greater than incremental cost. By contrast, distributed generation currently make no contribution to the common costs of the distribution network. So, arguably, retaining the existing price ceiling on charges could favour distributed generation over grid-connected generation.<sup>37</sup>

- 4.33 That said, our position is that the May 2016 proposal may not have ensured competitive neutrality between distributed generation and grid-connected generation. This is partly because of the possible problems with distributor market power discussed in the previous section. Another reason for our position is the possibility that distributors may have the incentive to discriminate against distributed generation by making them pay an excessive contribution to common costs.
- 4.34 To the extent that the May 2016 proposal failed to ensure competitive neutrality, distortions to competition and to efficiency would have been likely to result.
- 4.35 It will not be possible to resolve this issue until further progress has been made on the TPM review and the distribution pricing review. This is because these two reviews address the prices that Transpower and distributors can charge their customers, including generators. As a result, these two reviews will help to determine the extent of the contribution to common costs that distributed generation and grid-connected generation will make.
- 4.36 We intend to address the inefficiencies and competition problems associated with this issue, but will defer consideration of it until work has progressed on the TPM review and the distribution pricing review.
- 4.37 Transpower may have a role in the consideration of this issue. If after the publication of the TPM guidelines, when Transpower proposes a new TPM, then it should also recommend to the Authority further adjustments to the DGPPs that will promote efficiency and competitive neutrality between demand response, distributed generation and grid-connected generation.

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<sup>37</sup> Distributed generation generally make no contribution to transmission network common costs, with one exception: South Island distributed generation do sometimes pay HVDC charges, when their operation results in grid injection.

## Appendix A Code amendment

### 1 Title

This is the Electricity Industry Participation Code Amendment (Distributed Generation) 2016.

### 2 Commencement

This amendment comes into force on 9 January 2017.

### 3 Code amended

This amendment amends the Electricity Industry Participation Code 2010.

### 4 Schedule 6.4, clause 2 amended

In Schedule 6.4, replace clause 2(a) with:

"(a) subject to paragraph (i), **connection** charges in respect of **distributed generation** must not exceed the **incremental costs** of providing **connection** services to the **distributed generation**. To avoid doubt, **incremental cost** is net of—

"(i) if the **distributed generation** is included in a list **published** by the **Authority** under clause 2C(1), transmission costs that an efficient **distributor** would be able to avoid as a result of the **connection** of the **distributed generation** at the **nameplate capacity** specified for that **distributed generation** in the list; and

"(ii) **distribution** costs that an efficient **distributor** would be able to avoid as a result of the **connection** of the **distributed generation**:".

### 5 New clauses 2A, 2B, and 2C of Schedule 6.4 inserted

In Schedule 6.4, after clause 2, insert:

**"2A Transpower to provide reports to Authority in relation to distributed generation**

"(1) **Transpower** must, by 15 March 2017 (or such later date as the **Authority** may allow), provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Lower South Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.

"(2) **Transpower** must, by 30 August 2017, provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Lower North Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.

"(3) **Transpower** must, by 31 January 2018, provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Upper North Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.

"(4) **Transpower** must, by 31 January 2018, provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Upper South Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.

"(5) In this clause,—

"(a) Upper North Island is that part of the North Island situated on, or north and west of, a line—

"(i) commencing at 38°02'S and 174°42'E; then



- "(ii) proceeding in a generally north-easterly direction directly to 37°36'S and 175°27'E; then
- "(iii) proceeding north along the 175°27'E line of longitude; and
- "(b) Lower North Island is that part of the North Island not referred to in subclause (a); and
- "(c) Upper South Island is that part of the South Island situated on, or north of, a line passing through 43°30'S and 169°30'E, and 44°40'S and 171°12'E; and
- "(d) Lower South Island is that part of the South Island not referred to in subclause (c).

## **"2B Authority to review Transpower's reports in relation to distributed generation**

- "(1) The **Authority** must, as soon as practicable after receiving a report from **Transpower** under clause 2A,—
  - "(a) approve the report; or
  - "(b) decline to approve the report.
- "(2) If the **Authority** declines to approve the report,—
  - "(a) the **Authority** must, as soon as practicable,—
    - "(i) advise **Transpower** of its reasons for declining to approve the report; and
    - "(ii) direct **Transpower** as to how it should amend the report before resubmitting it; and
  - "(b) **Transpower** must amend the report in accordance with the **Authority's** direction, and resubmit the report to the **Authority**,—
    - "(i) for the report provided under clause 2A(1), within 10 **business days**; and
    - "(ii) for reports provided under clauses 2A(2), (3), or (4), within 20 **business days**.
- "(3) The **Authority** must, as soon as practicable after receiving a resubmitted report from **Transpower**,—
  - "(a) approve the report; or
  - "(b) decline to approve the report.
- "(4) Subclause (2) applies to the resubmitted report as if it were the report originally provided under clause 2A.

## **"2C Authority to publish list of distributed generation**

- "(1) The **Authority** must, after approving a report provided by **Transpower** under clause 2A, **publish** a list of **distributed generation** for the relevant region for the purposes of clause 2(a)(i).
- "(2) A list **published** under subclause (1) must include—
  - "(a) only **distributed generation** that is **connected** as at 6 December 2016; and
  - "(b) the **nameplate capacity** of the **distributed generation** as at 6 December 2016."

## **6 New clause 17.23A inserted**

After clause 17.23, insert:

### **"17.23A Delayed application of Electricity Industry Participation Code Amendment (Distributed Generation) 2016**

- "(1) Despite clause 2 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2016,—
  - "(a) until the close of 31 March 2018, Part 6 of this Code applies to the Lower

- South Island as if the Electricity Industry Participation Code Amendment (Distributed Generation) 2016 had not been made; and
- "(b) until the close of 30 September 2018, Part 6 of this Code applies to the Lower North Island as if the Electricity Industry Participation Code Amendment (Distributed Generation) 2016 had not been made; and
- "(c) until the close of 31 March 2019, Part 6 of this Code applies to the Upper North Island as if the Electricity Industry Participation Code Amendment (Distributed Generation) 2016 had not been made; and
- "(d) until the close of 30 September 2019, Part 6 of this Code applies to the Upper South Island as if the Electricity Industry Participation Code Amendment (Distributed Generation) 2016 had not been made.
- "(2) In this clause,—
- "(a) Upper North Island is that part of the North Island situated on, or north and west of, a line—
- "(i) commencing at 38°02'S and 174°42'E; then
- "(ii) proceeding in a generally north-easterly direction directly to 37°36'S and 175°27'E; then
- "(iii) proceeding north along the 175°27'E line of longitude; and
- "(b) Lower North Island is that part of the North Island not referred to in subclause (a); and
- "(c) Upper South Island is that part of the South Island situated on, or north of, a line passing through 43°30'S and 169°30'E, and 44°40'S and 171°12'E; and
- "(d) Lower South Island is that part of the South Island not referred to in subclause (c)."
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## Appendix B List of submitters

- B.1 We received 54 submissions on the consultation paper.<sup>38</sup> Table 5 lists the parties who made submissions.
- B.2 A summary of submissions is available from the Authority's website at <http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-part-6-dg-pricing-principles/development/authority-decision-on-the-review-of-dgpps-and-acot>.

**Table 5 List of parties making submissions**

Distributed generation owners	Other generators and retailers	Other network companies	Others
AD Harwood	Mighty River Power (Mercury)	Alpine Energy	Business NZ
Bryan Leyland		Buller Electricity	David Glass
Contact Energy		Electricity Networks Association	Greenpeace
Eastland Generation		Energy Trusts Association	HydroWorks
Electra Generation		Network Tasman	Major Electricity Users Group
Energy3		Orion	Molly Melhuish
Genesis Energy		Powerco	Northland Inc
Inchbonnie Hydro		PWC (on behalf of 14 distributors)	Ruapehu District Council
Independent Electricity Generators Association		Transpower	Solarcity
Infratil		Unison	Winstone Pulp International
John Irving			
Karaponga Hydro			
Kawatiri Energy			
King Country Energy			
Meridian			
Network Waitaki			
Nova Energy			

<sup>38</sup> Including three confidential submissions.

Distributed generation owners	Other generators and retailers	Other network companies	Others
NZ Energy			
NZ Wind Energy Association			
Omanawa Falls Hydro			
Pioneer Energy			
PowerNet			
Pupu Hydro Society			
Thomas Cameron			
Top Energy			
Tony Banks			
Trustpower			

## Appendix C Economic effects of the Code amendment

- C.1 This Appendix sets out the methodology used by the Authority to estimate the economic costs and benefits of the Code amendment to remove ACOT from the DGPP, relative to the current DGPP.
- C.2 The analysis uses the same underlying framework as that set out in in the May 2016 DGPP consultation paper, but is revised in a number of areas to:
- (a) reflect refinements to the Authority's DGPP Code amendment
  - (b) set out assumptions in more detail, including more information regarding the basis for key judgements
  - (c) address specific issues raised in submissions.

### Evaluation framework

- C.3 Potential incremental costs and benefits are considered from an economy-wide perspective. The assessment is made as at 1 April 2017, and considers the following 15 years. All future impacts are adjusted to present values using a 6% real discount rate.
- C.4 The Authority has evaluated potential benefits and costs of the Code amendment under two different TPM 'future state' options:
- (a) 'current TPM' – in which the current TPM remains in force (with changes resulting from the Transpower operational review of the TPM applying to calculation of transmission charges from 1 April 2017). This option is likely to drive incentives in the 2016/17 and 2017/18 capacity measurement periods (which would be used to set transmission charges for the 2018/19 and 2019/20 transmission pricing years). This option may also drive incentives over a longer period.
  - (b) 'prospective area-of-benefit-based TPM' – in which transmission investment costs are allocated to the beneficiaries of each investment. Any residual charges will be allocated to load customers based on their capacity. This prospective TPM is assumed to apply from 1 April 2020, in which case it would affect incentives from the 2018/19 capacity measurement period onwards.
- C.5 The next subsections describe the assessment of costs and benefits in more detail.

### Potential incremental costs

- C.6 The Authority has considered the following potential sources of incremental cost associated with the DGPP Code amendment:
- (a) Impact on reliability of supply
  - (b) Impact on transmission network costs
  - (c) Impact on distribution network costs
  - (d) Impact on transactions costs
  - (e) Impact on dynamic efficiency.
- C.7 The following sections consider each of these potential costs in more detail.

### Impact on reliability of supply

- C.8 Some submitters query whether changes to the ACOT provisions in the DGPPs will reduce reliability. For example, Pioneer Energy suggests that use of distributed generation sources enhances reliability.<sup>39</sup>
- C.9 The Authority does not expect the removal of ACOT provisions from the DGPPs to reduce reliability levels for the following reasons:
- (a) As regards the reliability of generation operation, nodal price signals in the wholesale energy market provide the primary incentive during tight supply periods. As discussed in a report we commissioned on security issues,<sup>40</sup> the DGPP ACOT changes will not directly affect the wholesale market, and will not therefore dilute nodal price incentives. Indeed, the DGPP Code amendment is expected to strengthen nodal price signals, because it will reduce the extent of inefficient operation of distributed generation in RCPD periods.
  - (b) As regards transmission network reliability, the Code amendment provides for ACOT payments being made pursuant to the DGPPs to continue, provided the Authority decides, based on Transpower's advice, that this is appropriate.
  - (c) Distributed generation is not inherently more reliable than other forms of generation. While it may (in some cases) be sited closer to demand sources, this does not necessarily make it more reliable as a source of supply. The reliability experienced by customers is a function of the wider system characteristics, and the types of generation connected to the system.

### Impact on transmission network costs

- C.10 The Authority has considered whether changes to the ACOT provisions in the DGPPs will increase transmission costs, because distributed generation-based alternatives will not be utilised, even where they are more efficient.
- C.11 The Authority does not expect such costs to arise. The Code amendment provides for ACOT payments being made pursuant to the DGPPs to continue, provided the Authority decides, based on Transpower's advice, that this is appropriate.

### Impact on distribution network costs

- C.12 The Authority has considered whether changes to the ACOT provisions in the DGPPs will increase distribution costs, because distributed generation-based alternatives will not be utilised, even where they are more efficient.
- C.13 The Authority does not expect such costs to arise. The DGPPs currently provide for distributors to make ACOD payments to distributed generation owners, where distributed generation produces distribution network cost benefits. The DGPP Code amendment will not alter this provision.

<sup>39</sup> Pioneer Energy, *RE: Transmission Pricing and Distributed Generation Policy Submissions*, submission to Electricity Authority, 26 July 2016, paragraphs 3.67 – 3.70.

<sup>40</sup> See Concept Consulting Group, *Winter capacity margin – potential effect of recent transmission pricing and distributed generation proposals*, November 2016.

### Impact on consumer prices

- C.14 Some submitters have suggested that changes to the ACOT provisions in the DGPPs will increase electricity prices to consumers.<sup>41</sup>
- C.15 For the reasons set out in paragraph C.128, the Authority expects the Code amendment to *reduce* rather than increase prices to consumers. It therefore does not expect economic costs to arise in this area.

### Transaction costs

- C.16 Some submitters have suggested that implementation of the DGPP Code amendment set out in the May 2016 consultation paper would cause a substantial increase in transaction costs.<sup>42</sup> The Authority has given further consideration to the transaction cost issue, and made refinements to the Code amendment that should reduce the extent of such costs.
- C.17 It is no longer proposing to remove the DGPPs entirely from Part 6 of the Code. Instead, the Code amendment provides for ACOT payments being made pursuant to the DGPPs to continue, provided the Authority decides, based on Transpower's advice, that this is appropriate.
- C.18 For parties utilising the default DGPP terms, the Code amendment will not affect connection terms or distribution charges payable between distributed generation owners and distributors. This refinement should mean there is no change in transaction costs for distributors and DGs, in respect of discussions about connection terms or distribution costs. This should significantly reduce transaction costs relative to the proposed Code amendment announced in May 2016.
- C.19 As regards the effect of the Code amendment on ACOT-related provisions, there is one substantive change relative to current practices. Transpower will identify which existing distributed generation are required to meet the Grid Reliability Standards. If the distributed generator is one of those identified, for cases where distributed generation owners and distributors are utilising the default DGPP terms the distributed generation owner will receive ACOT payments in the same way as currently set out in the DGPPs. This means there would be no requirement for negotiations between Transpower and existing distributed generation owners. This refinement is also expected to reduce transaction costs relative to proposal in the May 2016 DGPP Consultation Paper.
- C.20 The Authority notes that Transpower already undertakes analysis of reliability issues as part of its role as grid planner. This includes consideration of the contribution made by distributed generation, in parts of the grid where such plant is located. Furthermore, the Authority has set out a test for Transpower to identify the distributed generation that are required to meet the Grid Reliability Standards. This test is expected to further constrain transaction costs faced by Transpower.
- C.21 The Authority also expects that there would be transaction cost savings for some distributors and distributed generation owners from the Code amendment. Where distributed generation does not provide a transmission benefit and ACOT payments no longer applied, there would be cost savings from reduced effort in seeking to forecast

<sup>41</sup> See for example Pioneer Energy, *RE: Transmission Pricing and Distributed Generation Policy Submissions*, submission to Electricity Authority, 26 July 2016, final paragraph of cover letter.

<sup>42</sup> See for example Creative Energy Consulting Pty Ltd, *Review of the Electricity Authority's DGPP Consultation Paper*, July 2016, page 16.

periods of regional coincident peak demand, targeting such periods with discretionary generation, reconciling data, issuing invoices, and processing ACOT payments etc.

- C.22 While the Authority does not have detailed information on these costs, it notes that one sizeable distributor applies an annual charge of \$1,000 for each distributed generator to cover the “administrative costs in determining the ACOT, recovering the ACOT from end-consumers and distributing the ACOT to DGs”.<sup>43</sup> This figure only considers the distributor’s costs, and excludes costs for distributed generation owners.
- C.23 In light of all of these factors, the Authority considers that overall transaction costs are unlikely to materially increase in present value terms under the DGPP Code amendment.

### Dynamic efficiency

- C.24 Some submitters have argued changes to the ACOT provisions in the DGPPs will undermine dynamic efficiency because they represent an unanticipated change to a settled set of arrangements. In support of this view, submitters have cited a range of arguments which can be summarised as:
- (a) Remuneration of distributed generation based on avoided transmission charges is a long-standing feature of the regulated environment for electricity, dating back to use of bulk supply tariffs.
  - (b) A Ministerial Inquiry into the electricity industry was conducted in 2000, and it recommended the use of arrangements akin to the DGPPs.
  - (c) The recommendations from the Ministerial Inquiry were codified as Electricity Governance (Connection of Distributed Generation) Regulations in 2007. The DGPPs, which replaced the regulations from December 2010, have the same substantive provisions for ACOT payments.
  - (d) Investors in distributed generation have relied on an expectation that the arrangements reflected in the DGPPs would continue to allow a reasonable period for capital recovery.
- C.25 Each of these arguments is considered further below.

### Historic practice

- C.26 Some submitters argue that there has been a long-standing policy of remunerating distributed generation based on avoided transmission charges. For example, HoustonKemp state:
- “the remuneration of distributed generators on the basis of reduced transmission charges (ie, by reference to ACOT payments) has been in place for decades and is a longstanding element of the regulated environment for electricity in New Zealand.”<sup>44</sup>
- C.27 From the 1930s until the mid-1990s ECNZ (and its predecessors) sold power on bulk supply tariffs. These tariffs are understood to have included a substantial peak demand component. However, it would be incorrect to interpret these components as

<sup>43</sup> Vector, *Distributed generation electricity network - Avoided cost of transmission methodology*, Effective 1 April 2016.

<sup>44</sup> HoustonKemp, *Assessment of the Electricity Authority’s proposal to remove the distributed generation pricing principles*, page 36.



transmission charges per se. On the contrary, generation and transmission services were bundled for most of the period. Nor would it be correct to characterise these charges as being set in a regulated environment.

- C.28 Transmission charges were fully unbundled when Transpower commenced operation as an independent company in 1994.<sup>45</sup> From this time until 2004 Transpower had significant influence over its charging structures, as they were not subject to specific regulatory control. The charge structures changed a number of times during this period, and are understood to have included substantial capacity-based elements such as peak demand, capacity nomination, capacity over-run, and/or or charges based on flow-tracing at different times.
- C.29 Another important development was the establishment of the wholesale electricity market in October 1996 – this determined revenues payable to generators (including distributed generation) that were selling energy into the spot market. The wholesale market rules were a multilateral contract, and did not become subject to specific regulatory control until 2004.
- C.30 In summary, in the decades to 2004, distributed generation was ‘remunerated’ either by:
- The distributed generation investor benefiting from lower expenditure on bulk supply tariffs, or (later) on the sum of its wholesale energy and transmission charges. Neither bulk supply tariffs nor wholesale/transmission charges were subject to explicit regulatory control, and both underwent significant changes over the period.
  - Alternatively, the distributed generation investor had a contract to sell services to a third party. Any such contract was negotiated bilaterally and there was no regulatory requirement on distributors (or their predecessors) to pay distributed generation owners on the basis of avoided transmission charges (assuming they could even be identified at the relevant time).
- C.31 Accordingly, it is not reasonable to characterise ACOT payments as being a long-standing element of the regulated environment for electricity.

### ***Caygill Ministerial Inquiry***

- C.32 Some submitters argue that the current distributed generation rules date from a Ministerial inquiry conducted in the 2000s. For example, Trustpower states that “the genesis of the current distributed generation rules can be found in the Caygill inquiry into the electricity industry conducted in the 2000” [*sic*] which recommended “in order to encourage new investment in distributed generation, *the savings in transmission charges as a result of that new investment* [should] *be passed on to the distributed generator.* (emphasis added in submission)”.<sup>46</sup>
- C.33 The Authority acknowledges this view, but considers that the Inquiry’s findings need to be considered in their entirety. In particular, the Inquiry’s recommendations relating to transmission *charges* are relevant in this matter.

<sup>45</sup> Some preparatory steps were taken earlier when Transpower became a separate wholly-owned subsidiary of ECNZ.

<sup>46</sup> Trustpower *Proposal to remove Distributed Generation Pricing Principles*, submission to the Electricity Authority, 26 July 2016, at paragraph 3.3.1.

- C.34 The Inquiry recommended that a set of transmission pricing principles be developed, which among other things should encompass:
- (a) “pricing for new entrants should provide clear locational signals”
  - (b) “the sunk costs of the transmission grid should be allocated in a way that minimises distortions to decisions about the use of and new investment in the grid”
  - (c) “the pricing structure should include a variable element based on peak demand in order to provide an incentive to minimise network constraints”.
- C.35 In the Authority’s view, these statements indicate an intent for distributed generation to be remunerated on the basis of avoided transmission charges, on the assumption that such *charges* would largely reflect avoided transmission *costs*.
- C.36 In support of this interpretation, the Authority notes the Inquiry report stated that distributed generation should be able to “be paid the transmission costs avoided by virtue of being located within the network” (emphasis added).<sup>47</sup>
- C.37 The Authority believes its Code amendment is consistent with the intent of the Ministerial inquiry – as they provide for distributed generation to receive an ACOT payment, where it provides a genuine transmission benefit – i.e. where it reduces transmission costs.

***Distributed generation regulations and DGPPs***

- C.38 Some submissions cite the Electricity Governance (Connection of Distributed Generation) Regulations 2007 (on which the DGPPs are based) to support their view that ACOT payments should reflect avoided transmission charges rather than avoided costs,<sup>48</sup> and that this was a clear and settled policy intent.
- C.39 The Authority does not share this view. To the extent ACOT-related issues were considered in the development of regulations, the policy intent does not appear to have been particularly clear or settled.
- C.40 The original discussion paper of September 2003 stated that:
- a “lines network company will provide for the distributed generator to receive by payment or other reward a minimum of 85% of the calculated avoided cost of transmission.”<sup>49</sup>
- C.41 In September 2006, draft regulations were released that stated:
- “avoidable costs do not include costs that are merely shifted from the distributor to other parties as a result of the connection and operation of the generation (this is relevant to the issue of avoided transmission costs).”<sup>50</sup>
- C.42 This provision was not included in the final regulations which came into effect in August 2007. Instead the regulations included the following provisions:<sup>51</sup>

<sup>47</sup> Report to Minister, *Inquiry into the Electricity Industry*, June 2000, at paragraph 247.

<sup>48</sup> For example, see Trustpower *Proposal to remove Distributed Generation Pricing Principles*, submission to the Electricity Authority, 26 July 2016, at section 3.4.

<sup>49</sup> Ministry of Economic Development, *Facilitating Distributed Generation*, discussion paper, September 2003.

<sup>50</sup> Electricity Governance (Connection of Distributed Generation) Regulations, draft of September 2006.

<sup>51</sup> Electricity Governance (Connection of Distributed Generation) Regulations 2007, Schedule 4.

“connection charges in respect of distributed generation must not exceed the incremental costs of providing connection services to the distributed generation. For the avoidance of doubt, incremental cost is net of transmission and distribution costs that an efficient service provider would be able to avoid as a result of the connection of the distributed generation”.

- C.43 Some submitters cite this to support their view that ACOT payments under default connection terms were intended to reflect avoided transmission charges. However, the regulations did not expressly reference avoided transmission charges. Nor do all distributors interpret the DGPPs (and presumably the prior distributed generation regulations) as requiring ACOT payments to be made based on avoided transmission charges. As noted by the Authority in 2013:<sup>52</sup>
- (a) Of 29 Distributors, 23 had an ACOT payment policy and six did not.
  - (b) 18 (of the 23) ACOT payment policies provided for payments to distributed generation based on avoided transmission charges.
  - (c) Five distributors had ACOT payment policies that were not linked directly to the Transpower interconnection rate and calculation method. Of those, two referenced methods other than a simple peak reduction such as distribution network savings, and two identified that there were limits to charges or the benefits considered in determining charges. One stated that their objective is to avoid subsidising generation.
- C.44 Another factor relevant to the degree of reliance to place on the regulations is the process used for their formation. Examination of submissions from the time indicates the process was subject to some criticism. Although the government had established a specialist regulatory body (the Electricity Commission) part way through the regulation development process, the task of finalising distributed generation arrangements was not referred to that body. Nor was any cost benefit evaluation undertaken on the regulations. Both of these factors attracted some adverse comment at the time.<sup>53</sup>
- C.45 Finally, the current DGPPs were not subject to any detailed scrutiny at the time they were introduced. Rather, the relevant provisions in the distributed generation regulations were incorporated in the initial Code (as DGPPs) when it was formed by consolidation of earlier instruments.
- C.46 Against this backdrop, the Authority does not believe that it is reasonable to characterise the remuneration of distributed generation based on avoided transmission *charges* as a clear and settled regulatory bargain, or that it was expressly intended for distributed generation to receive ACOT payments where there is no avoided transmission cost.

***Investments have been made in reliance on DGPPs and previous policy settings***

- C.47 Some submitters argue that they have made significant investments in distributed generation based on the previous policy settings. For example, Trustpower states that:

<sup>52</sup> Electricity Authority, *Transmission Pricing Methodology: ACOT payments for Distributed Generation, Working Paper*, 19 November 2013, paragraphs 6.5 to 6.9.

<sup>53</sup> See submission from Major Electricity Users Group, dated 10 October 2006, and attached report from the New Zealand Institute of Economic Research (NZIER). The Authority notes the principal author of the NZIER report was Dr Brent Layton, director of the NZIER at the time.

“investors have a strong expectation that the policy settings under which their investments were made will remain in place to provide them with a reasonable opportunity to recover the cost of their investment, including an appropriate return on that investment.”<sup>54</sup>

C.48 Similarly, King Country Energy states:

“the impact of the removal of the DGPP would significantly erode investor confidence in investing in existing and new DG”.<sup>55</sup>

C.49 At the outset, the Authority notes that ACOT payments are only one component of the remuneration for distributed generation. For most distributed generation, other sources (such as energy sales to the wholesale market or to retailers) are expected to account for the majority of revenues. These other revenue sources are not expected to be directly affected by the Authority’s DGPP Code amendment.

C.50 For diesel-fired plant (a minority of total distributed generation capacity), ACOT payments are likely to account for a more significant proportion of external revenues. However, for some of these plants, investment is likely to have been motivated by other benefits – such as back-up power in the event of loss of mains supply (e.g. for hospitals). These benefits are unlikely to be affected by the Authority’s DGPP Code amendment. In addition, smaller diesel units may be more easily redeployed than other forms of distributed generation if there is no longer a financial case for their retention in current use.

C.51 Second, there is around 1,500 MW<sup>56</sup> of distributed generation and notionally embedded generation capacity on the system. Approximately 950 MW of this capacity was built before the DGPPs (or the preceding distributed generation regulations) existed. As noted earlier, the arrangements applying at the time these investments were committed were a mix of custom and contracts, and could not reasonably be characterised as a regulated environment.

C.52 Nor does it appear likely that historic distributed generation investors would have fully anticipated the sizeable increase in interconnection charges<sup>57</sup> (and therefore ACOT payments based on the DGPP default terms) that has occurred since 2012, as shown in in Figure 4.

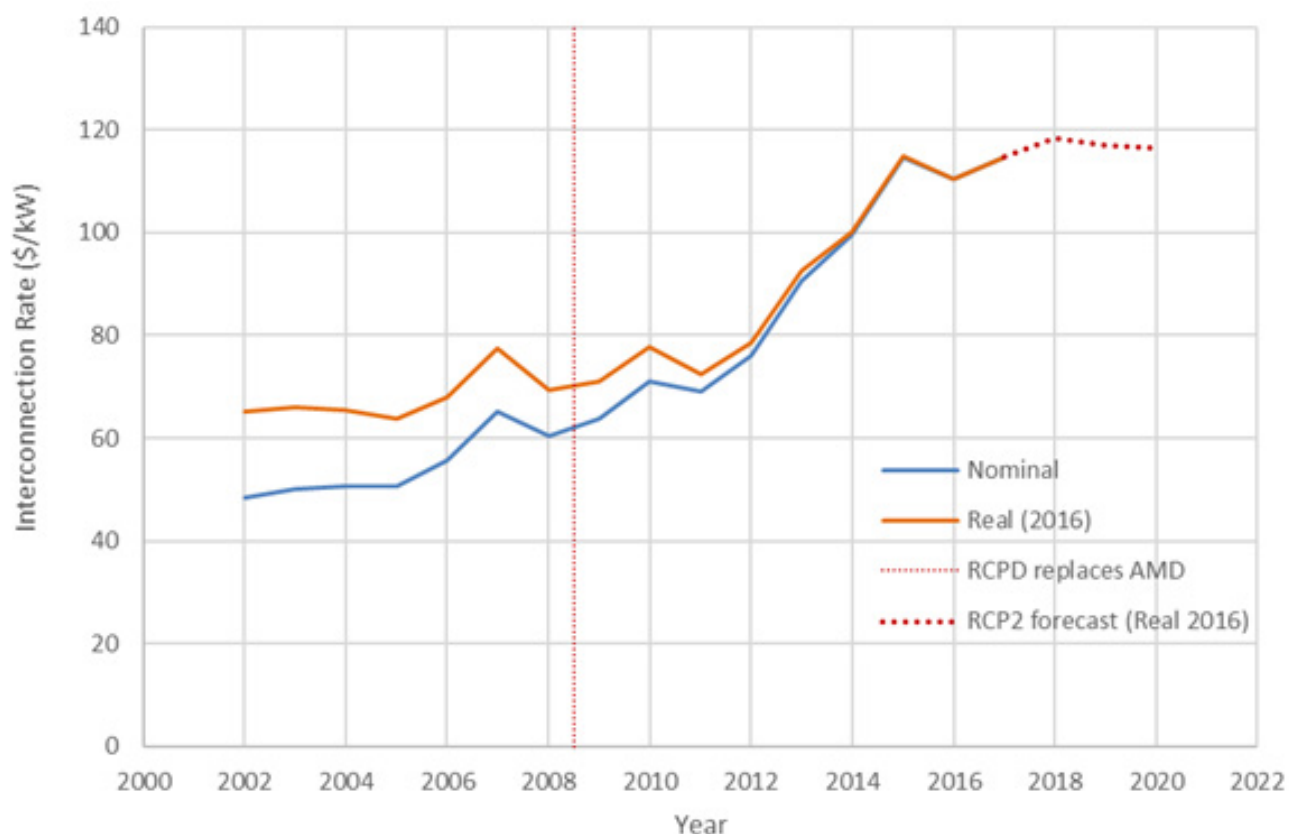
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<sup>54</sup> Trustpower submission on DGPP Consultation Paper, at 3.6.2.

<sup>55</sup> King Country Energy submission on DGPP Consultation Paper.

<sup>56</sup> This estimate includes notionally embedded generation which may also receive ACOT-like payments. Based on plant where the commissioning date was known, around 550 MW of new capacity was commissioned since 2007. Some of the distributed generation capacity that was commissioned post-2007 may have been committed to before the distributed generation regulations came into force.

<sup>57</sup> Interconnection transmission charges are levied on grid offtake customers based on their share of load during periods of regional coincident peak demand. They are a major driver of the size of ACOT payments.

**Figure 4: Interconnection rate**

- C.53 The distributed generation regulations came into force in August 2007 (and were succeeded by the DGPPs in 2010), and set default terms to apply where distributors and distributed generation owners could not agree on negotiated terms. Distributed generation investors since that date are likely to have taken the distributed generation regulations and subsequent DGPPs into consideration in their investment decisions. However, the Authority does not accept that investors could reasonably expect the assured future continuation of the regulations (or DGPPs), irrespective of their efficiency merits.
- C.54 The record shows that there has been debate about the basis for any ACOT payments under the distributed generation regulations from the outset.<sup>58</sup> Indeed, given the oscillations in policy regarding the basis for ACOT payments evident through the development of the distributed generation regulations, it is hard to see how the regulations could have been perceived as being invulnerable to further change.
- C.55 Since it was established, the Authority has not taken any actions to suggest that it views ACOT payments based on avoided charges as efficient, or that such payments would continue. On the contrary, the Authority has been signalling its concerns about this issue since it began work on ACOT payments as part of the TPM review.

<sup>58</sup> For example, see *Powerco submission on Facilitating Distributed Generation - Powerco's response to the Discussion Paper*, 31 October 2003, where it states "distributed generators would have a strong incentive to connect to distribution networks, rather than the national grid, even though there is no cost saving in doing so."

- C.56 The Authority released an ACOT working paper in November 2013 that stated: “The Authority’s preliminary view is that a review of the provisions of Schedule 6.4 [DGPPs] is therefore warranted with a view to ensuring a stronger link between ACOT payments and efficiency benefits”.<sup>59</sup>
- C.57 The Authority’s concerns have not gone unnoticed by external parties. For example, in September 2015, an equity research report on the New Zealand utilities sector estimated that ACOT revenue for one large participant was around \$25 million per year. The report noted the wider review being undertaken by the Authority, and assessed the loss of the ACOT revenue for that participant as having an 80% likelihood.
- C.58 Against this backdrop, it is not reasonable to characterise the DGPP proposals announced in May 2016 as an unexpected policy surprise. Moreover, for those parties using the default DGPP terms, the Authority’s Code amendment will see changes come into effect from 1 April 2018 for distributed generation in the lower South Island. This will be almost 4½ years after the Authority released the November 2013 Working Paper. For parties using the default terms in other regions, the changes will take effect from 1 October 2018 or later – around five years after the Working Paper was released.
- C.59 On the issue of investor expectations, the Authority also notes that the largest single investor (by MW) in new distributed generation since the distributed generation regulations came into force has been Meridian Energy. Meridian accounts for approximately 47% of the ~550 MW of new distributed generation capacity commissioned during the period 2007-2016. Meridian has stated that it:
- “never assumed the indefinite continuation of ACOT payments for any of these wind farms. Our planning took into account the possibility of ACOT payments, but like any other part of the Code we have always known that it could change. Indeed, our contractual agreements with distributors all anticipate the possibility of regulatory change of the type proposed in respect of ACOT and allow for payments to be adjusted or removed in those circumstances.”<sup>60</sup>
- C.60 Some might question whether Meridian’s statement is influenced by broader commercial motivations, such as support for proposed TPM changes released in parallel with the DGPP proposals. While such a motivation cannot be ruled out, Meridian will presumably be well aware that the DGPP Code amendment is an initiative in its own right, and could well proceed in isolation from, or alongside a Code amendment to the TPM.
- C.61 More generally, the Authority has considered whether to grandfather existing distributed generation in the DGPPs. If the Authority were to require the ongoing retention of ACOT payments that are obviously inefficient on the grounds removing them would create uncertainty for those that invested to benefit from the inefficiency, this would encourage and reward rent seeking behaviour.
- C.62 Requiring the ongoing retention of such payments would also penalise those who had correctly realised the payments would not survive an efficiency review a regulator must inevitably conduct, given statutory objectives. Such action by a regulator would discourage others from acting efficiently in future.

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<sup>59</sup> Electricity Authority, *Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation: Working Paper*, 19 November 2013 at 1.18.

<sup>60</sup> Meridian Energy, *Review of distributed generation pricing principles – Consultation Paper*, submission on DGPP Consultation Paper, 26 July 2016.

- C.63 Regulatory changes can potentially affect the cost of capital, however, it's important to take a balanced perspective on these potential effects. We don't consider that altering the ACOT arrangements for existing distributed generation is likely to have an upward impact on the cost of capital. However, even if it did have such an effect, it is important to be aware of potentially offsetting dynamic efficiency effects that would reduce the cost of capital. That is, one effect of the Authority not grandfathering ACOT payments is that a forward-looking investor can be more confident the Authority won't apply a grandfathering policy in the future when dealing with other contentious issues. This might avoid future costs for the forward-looking investor, and so reduce their cost of capital. We acknowledge that the net effect is not clear-cut. However, it is reasonable for the regulator to take into account both influences on the cost of capital.
- C.64 Furthermore, the rate of change within the electricity sector has accelerated. New technologies and business models are rapidly emerging, and further changes are expected. The Code will need to evolve to take account of these developments. A philosophy of seeking to preserve the value of existing commercial positions would be inconsistent with the objective of fostering efficiency, and pursuing the long-term interests of consumers.
- C.65 Finally, we would observe that grandfathering is not typically applied by electricity companies to their own customers. None of the parties making arguments on the basis of regulatory certainty—some of whom are retailers as well as generators—have adopted grandfathering in regard to changes in the electricity prices they charge to consumers. The common practice of these parties is to raise prices for consumers without applying a grandfathering policy (ie, freezing prices for existing customers). Similarly, a number of retailers significantly reduced buy-back rates for electricity injected into the grid from domestic solar panels in 2015. These retailers adopted transitional arrangements for existing solar customers, but none of them adopted a grandfathering policy (ie, retaining the same buy-back rates for existing customers). Similarly, many distributors have substantially increased total charges for their existing services without applying a grandfathering policy.

***Overall conclusion re dynamic efficiency effects***

- C.66 The Authority does not consider that the DGPP Code amendment will give rise to dynamic efficiency losses. The principal reasons are:
- (a) There has been no long-standing historic regulatory policy for distributors to make ACOT payments to distributed generation on the basis of avoided transmission charges – rather any such payments have been a matter of custom or contract.
  - (b) In more recent time, the distributed generation regulations (and DGPPs) set default terms available for new distributed generation since August 2007. However, distributed generation investors could not reasonably expect the assured future continuation of the present arrangements given their adverse efficiency effects.
  - (c) Requiring the ongoing retention of inefficient ACOT payments going forward would create adverse incentives, and would not be in the long-term interest of consumers
  - (d) The Code amendment may have potentially offsetting dynamic efficiency effects that would reduce the cost of capital, as it will enable a forward-looking investor to

be more confident the Authority won't apply a "grandfathering" policy in future when dealing with other contentious issues.

- C.67 Indeed, the Authority expects that the Code amendment will promote dynamic efficiency, because it demonstrates that the industry regulator will pursue changes where they promote the statutory objective. While the dynamic efficiency benefits have not been quantified in this analysis, the Authority believes that they are likely to be material.

### Potential incremental benefits

- C.68 The Authority has considered the following potential sources of incremental benefit arising from the proposed DGPP changes:

- (a) Reduced inefficient operation of existing generation.<sup>61</sup>
- (b) Reduced inefficient investment in new generation.
- (c) Reduced inefficient expenditure to retain existing generation in operation.
- (d) Reduced inefficient consumption decisions caused by distorted prices.

- C.69 The following sections consider each of these potential benefits in more detail.

### Benefit from reduced inefficient operation of existing generation

- C.70 This subsection considers the economic costs that can arise when generators operate in order to receive ACOT payments even though:

- (a) their short-run marginal cost (SRMC) exceeds the marginal value of energy at the time and
- (b) there are insufficient offsetting reductions in network costs.

### *Counterfactual - current TPM*

- C.71 Some distributed generation, and some grid-connected generation that is notionally embedded, seek to operate in potential regional peak periods, in order to receive ACOT payments.

- C.72 From an energy market perspective, such operation:

- (a) will almost always be efficient for existing geothermal and wind generation, which is expected to have a very low SRMC in most cases
- (b) will usually be broadly efficient for existing hydro and gas-fuelled generation, whose SRMCs are unlikely to greatly exceed the marginal value of energy at peak times. However, there may be some instances where avoidable costs are incurred to increase peak generation (to target ACOT payments) and these costs exceed the value of energy market and network benefits.
- (c) can be inefficient for existing liquid-fuelled generation whose SRMC may considerably exceed the marginal value of energy during RCPD measurement periods – except in cases where such operation produces offsetting network cost savings.

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<sup>61</sup> The term "generation" is used in this section to refer to distributed generation and notionally embedded generation, given that the DGPP can create incentives that affect both forms of generation.



C.73 The Authority expects that the DGPP Code amendment would reduce the extent of inefficient generation operation that would otherwise occur. Where it is efficient for generation to operate to provide transmission substitution, the Authority expects this to continue under the Code amendment.

C.74 The Authority estimates the economic benefit (B) as:

$$B = Q_{liq} \times (SRMC - V_e) \times N_{hh} / 2 \times R$$

Where:

$Q_{liq}$  is the average amount of liquid-fuelled generation that operates to receive ACOT (in MW), and does not produce material network cost savings

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

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

$N_{hh}$  is the number of potential RCPD periods in which such generation operates, in order to 'hit' the N=100 actual RCPD periods. The division by two is to deliver a result in MWh, as RCPD periods are based on half hour trading periods.

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

C.75 The estimated values for these parameters and the reasoning for each is set out below:

- (a)  $Q_{liq}$  is estimated at 5 MW in the lower case. This compares to approximately 22 MW of diesel-fired distributed generation capacity located in the LNI and LSI regions. Neither of these regions is thought to be approaching inter-regional transmission capacity constraints during RCPD periods (an important indicator or the likelihood of DG providing transmission benefits). The estimate of 5 MW is equivalent to assuming that approximately 25% of the capacity in these regions will run in RCPD periods, and not produce offsetting network saving. It also assumes that all other diesel-fired distributed generation operation is producing network benefits commensurate with ACOT payments. The higher case estimate is 40 MW. This is equivalent to total diesel capacity outside the USI region. The USI region is the area most likely to first experience inter-regional transmission capacity constraints. However, even for this region, it is possible that use of distributed generation is inefficient in some cases. The base case estimate is the mid-point between the lower and higher cases.
- (b) The lower case SRMC estimate is \$300/MWh. This is the same value as used in analysis of Transpower's proposed operational TPM changes in 2015.<sup>62</sup> More recent information indicates that this may be too low as it is based solely on fuel and variable operating costs. It does not include some other costs that would probably be avoided if smaller diesel-fired distributed generation is not operated to target ACOT payments. These include demand monitoring and management costs. Information submitted by one network company<sup>63</sup> has indicated that smaller diesel-fired distributed generation typically requires a payment equivalent to ~\$600/MWh to target operation in peak periods. This suggests that the SRMC of small diesel-fired distributed generation is around this level. The higher case

<sup>62</sup> See [www.ea.govt.nz/dmsdocument/19327](http://www.ea.govt.nz/dmsdocument/19327).

<sup>63</sup> Meeting attended by staff of Electricity Authority and a network company, 18 August 2016.

estimate adopts the \$600/MWh figure. The base case estimate is the mid-point between the lower and higher cases.

- (c)  $V_e$  is estimated at \$100/MWh for all cases. It is based on the level of spot prices observed in RCPD periods in 2015. This is a proxy for the average price in the 150 periods that distributed generation is assumed to operate to target ACOT payments.
  - (d)  $N_{hh}$  is estimated at 150 trading periods for all cases. This is the same value as used in earlier analysis by the Authority.<sup>64</sup>
  - (e)  $R$  is estimated at 90% for the lower case. The  $Q_{liq}$  value for this case is 5 MW, which is less than the capacity of diesel distributed generation capacity connected to distributors subject to price-quality control. For these distributors, it seems likely that ACOT payment terms will reference the DGPPs in some way to assure recoverability of costs for the host distributor. Accordingly, there is a high likelihood that altering the DGPPs will lower inefficient distributed generation operation. The higher case estimate is 60%. For this case, the  $Q_{liq}$  value includes some distributed generation connected to distributors that are not subject to price-quality control, and therefore there is more uncertainty about ACOT payment terms. Nonetheless, it appears more likely than not that ACOT payment terms will reference the DGPPs. The base case estimate is the mid-point between the lower and higher cases.
- C.76 In terms of timing, the Code amendment is expected to affect operational incentives in the year preceding the change in the DGPP for the reasons set out in paragraph C.4. Although some benefit is expected to accrue from 1 April 2017 due to improved operational incentives for distributed generation in the LSI and LNI regions, this has not been quantified. Instead, benefits accrue from 1 April 2018, because the DGPP change will affect operational incentives for distributed generation in all regions from that date.

### Benefit from reduced inefficient investment in new generation

- C.77 This subsection deals with the economic costs that can be incurred when new distributed generation or notionally embedded generation is constructed, justified in part by an expectation of revenue from ACOT payments, even though:
- (a) its long-run marginal cost (LRMC) exceeds the LRMC of some other grid-connected generation that could have been constructed instead, and
  - (b) there are insufficient offsetting network cost savings.

### ***Counterfactual - current TPM***

- C.78 The combination of the current DGPP and the current TPM can encourage inefficient investment in distributed generation or notionally embedded generation.
- C.79 The Authority expects that the DGPP Code amendment would significantly reduce the extent of inefficient investment. Where it is efficient for investment to occur to provide transmission substitution, the Authority expects this to continue under the Code amendment.
- C.80 The Authority estimates the economic benefit (B) as:

<sup>64</sup> See [www.ea.govt.nz/dmsdocument/19327](http://www.ea.govt.nz/dmsdocument/19327).

$$B = Q_{dg} \times P_{no\_ntwk\_ben} \times ACOT_{pv} \times P_{ineff} \times RCPD \times R$$

Where:

$Q_{dg}$  is the nameplate capacity of distributed generation constructed per year in MW

$P_{no\_ntwk\_ben}$  is the proportion of such investment that does not yield material network cost savings

$ACOT_{pv}$  is the present value of ACOT payments over 15 years in \$/kW

$P_{ineff}$  is the average proportion of ACOT payments that is 'lost' as inefficiency

RCPD is the % of nameplate capacity that contributes during RCPD periods

R is the percentage reduction in inefficient generation investment as result of the Code amendment.

C.81 The estimated values for these parameters and the reasoning for each is set out below:

- (a)  $Q_{dg}$  is estimated at 10 MW/year in the lower case. This is substantially lower than observed average distributed generation capacity growth between 2008 and 2016 which was approximately 25 MW/year for distributed generation connected to distributors subject to price control, and approximately 50 MW/year across all distributors. Looking ahead, the overall rate of national demand growth is likely to influence new distributed generation investment decisions. Transpower's most recent long-term projection implies annual peak demand growth of around 70MW/year.<sup>65</sup> In light of this, the higher case estimate is 30 MW/year. The base case estimate is 20 MW/year, which is the mid-point between the lower and higher cases.
- (b)  $P_{no\_ntwk\_ben}$  is estimated by reference to the proportion of recent distributed generation investment that has been observed in the LNI and LSI regions. Since 2007, over 80% of distributed generation investment (by MW) has been in these regions, neither of which are thought to be approaching transmission capacity constraints during RCPD periods. There is no particular reason to expect a change in the future pattern of distributed generation investment across regions. In light of this,  $P_{no\_ntwk\_ben}$  is estimated at 50% in the lower case, 80% in the higher case, and 65% in the base case.
- (c)  $ACOT_{pv}$  is estimated as \$1,180/kW of RCPD capacity. It assumes the 2016/17 interconnection rate of \$114.6/kW continues in real terms.  $ACOT_{pv}$  represents the present value of future ACOT payments, per kW of capacity that contributes in RCPD periods.
- (d)  $P_{ineff}$  represents the proportion of ACOT payments 'lost' as inefficiency, for distributed generation that does not yield material network savings (accounted for by the  $P_{no\_ntwk\_ben}$  adjustment above). Inefficiency losses include selecting generation options that are costlier than the best grid-connected alternatives, and/or utilising higher cost connection arrangements to ensure a plant qualifies as distributed generation. For distributed generation that does not yield material

<sup>65</sup> See <https://www.transpower.co.nz/sites/default/files/plain-page/attachments/Transpower%20National-Regional%20Peak%20Demand%20Forecasts%20Feb-2015%20Information%20Document.pdf>.

network savings, ACOT payments effectively represent a subsidy<sup>66</sup> that is only available to a subset of generation. This can enable distributed generation to be commercially viable against alternatives that have better underlying economics. In equilibrium, a sizeable proportion of ACOT payments is likely to be utilised to offset inefficiencies, because there will be an incentive to invest in distributed generation up to the point where ACOT payments are insufficient to offset inefficiency hurdles. In light of these factors,  $P_{ineff}$  is estimated at 50% in the base case, 25% in the lower case, and 75% in the higher case.

- (e) RCPD is the % of nameplate capacity that contributes during RCPD periods. The lower estimate is approximately 41% and is based on the observed average ACOT payment per kW in 2014 (\$61.5m / ~1,500MW<sup>67</sup>), divided by the then prevailing interconnection rate (\$100/kW)<sup>68</sup>. It is expected to be biased downwards because some distributors are reported to not make ACOT payments based on avoided transmission charges. The higher case estimate is 52% and is based on the weighted average of estimated firmness contributions in RCPD periods for different generation types. The base case estimate is 47% and is the mid-point of these values.
- (f) R is the percentage reduction in inefficient generation investment as result of the Code amendment. Absent the DGPP provision, distributors subject to price-quality control are not expected to have recoverability for any ACOT payments to new distributed generation.<sup>69</sup> For this reason, there is a high likelihood that inefficient investment will cease for distributed generation on distributors subject to price-quality control. For distributors not subject to price control, distributed generation owners will no longer be able to require ACOT payments (as a default) based on avoided transmission charges. Distributors might voluntarily make such payments, or invest themselves in distributed generation to reduce transmission charges. In light of these factors, the lower case assumes a 75% reduction in inefficient investment (reflecting  $Q_{dg}$  is for non-exempt distributors). The higher case assumes a 50% reduction (reflecting  $Q_{dg}$  is for all distributors). The base case estimate is the mid-point between the lower and higher cases.

C.82 In terms of timing, the benefits from reduced inefficient investment are assumed to commence from the time the Code amendment is announced.

### Benefit from reduced inefficient retention of existing generation

- C.83 This subsection deals with the economic costs that can arise when existing distributed generation and notionally embedded generation is retained in service, even though the expenditure necessary to achieve retention exceeds the economic benefits.
- C.84 All forms of generation face costs to remain in service (as distinct from SRMC which reflect costs which vary directly with output). These can include regular maintenance

<sup>66</sup> In this context, the term subsidy refers to payments made as a grant or contribution of money – i.e. without an expectation of services of equivalent or greater value being provided in return.

<sup>67</sup> This includes estimated notionally embedded capacity, the payments for which are expected to be included in the total ACOT payment quantum.

<sup>68</sup> This is the interconnection rate that applied in 2014, which is the relevant date for this calculation. The 2016/17 interconnection rate (\$114.6/kW) is used in other parts of the analysis, as they are forward-looking.

<sup>69</sup> The Code change to DGPPs will also affect existing distributed generation utilising the default terms, but this section is only about new distributed generation.

costs, or lumpy expenditures to repair damage or worn components, meet environmental or safety standards etc. Even generation forms that typically have long lives such as hydro plants will face periodic expenditure to repair or replace electrical and mechanical equipment, control systems etc.

- C.85 Inefficient retention could occur where generation owners decide to incur stay-in-business expenditures, and the present value of these exceed the benefits derived from wholesale energy sales and any network cost saving.

***Counterfactual - current TPM***

- C.86 The combination of the current DGPP and the current TPM can encourage inefficient retention of existing distributed generation or notionally embedded generation.
- C.87 The Authority expects that the DGPP Code amendment would significantly reduce the extent of inefficient retention decisions. Where retention is the most efficient option to provide a transmission substitution service, and it would not otherwise occur, the Authority expects this continue under the Code amendment.
- C.88 The Authority estimates the economic benefit (B) as:

$$B = Q_{\text{renew}} \times P_{\text{no\_ntwk\_ben}} \times ACOT_{\text{pv}} \times P_{\text{ineff}} \times RCPD \times R$$

Where:

$Q_{\text{renew}}$  is the average nameplate capacity of distributed generation that is subject to retention decisions each year

$P_{\text{no\_ntwk\_ben}}$  is the proportion of generation does not yield material network cost savings

$ACOT_{\text{pv}}$  is the present value of ACOT payments over 15 years in \$/kW

$P_{\text{ineff}}$  is the average proportion of ACOT payments that is 'lost' as inefficiency

RCPD is the % of nameplate capacity that contributes during RCPD periods

R is the percentage reduction in inefficient generation retention as result of the Code amendment.

- C.89 The estimated values for these parameters and the reasoning for each is set out below:
- (a)  $Q_{\text{renew}}$  is estimated by considering the existing distributed generation capacity on the system, and dividing this by the average economic life of plant. The resulting figure is the average distributed generation capacity that is subject to retention (i.e. reinvestment) decisions in each year. In reality, this profile may be lumpy, but without detailed knowledge of plants an average annual figure has been used. For the lower case, the estimate is 17 MW/year. This is based on the observed capacity of distributed generation on distributors subject to price-quality control (830 MW) and a 50-year average economic life span. This life span is probably conservatively long, even for hydro generation which typically requires periodic capital expenditure to remain in service. The higher case is 36 MW/year and is based on total existing distributed generation capacity of 1,080 MW and an average assumed life span of 30 years. Most types of distributed generation (diesel, gas-fired, wind, geothermal) would be expected to require significant reinvestment or replacement within this period. The base case estimate is 24

MW/year. It is based on distributed generation capacity of 955 MW (the mid-point of the other cases) and a 40-year life span.

- (b)  $P_{\text{no\_ntwk\_ben}}$  is estimated by reference to the proportion of existing distributed generation capacity in the LNI and LSI regions. There is currently over 80% (by MW) of total distributed generation capacity in these regions, neither of which are thought to be approaching transmission capacity constraints during RCPD periods. In light of this,  $P_{\text{no\_ntwk\_ben}}$  is estimated at 50% in the lower case, 80% in the higher case, and 65% in the base case.
- (c)  $\text{ACOT}_{\text{pv}}$  is estimated as \$1,180/kW of RCPD capacity. It assumes the 2016/17 rate of \$114.6/kW continues in real terms. It represents the present value of future ACOT payments, per kW of capacity that contributes in RCPD periods.
- (d)  $P_{\text{ineff}}$  represents the proportion of ACOT payments 'lost' as inefficiency. The concept is similar to that described above for the new investment analysis, but in this case a lower proportion of ACOT payments is assumed to be lost as inefficiency. The key reason for the difference is that reinvestment in existing renewable distributed generation is assumed to generally be lower cost than investing in new distributed generation (or grid-connected generation) because some costs have already been sunk. However, this is clearly not always the case, given that some older renewable plants have been retired in the past rather than being retained. In light of these factors,  $P_{\text{ineff}}$  for retention decisions has been estimated at one fifth of the corresponding value for new investment decisions. This means  $P_{\text{ineff}}$  is estimated at 10% in the base case, 5% in the lower case, and 15% in the higher case.
- (e) RCPD is the % of nameplate capacity that contributes during RCPD periods. The lower estimate is approximately 41% and is based on the observed average ACOT payment per kW in 2014 (\$61.5m / ~1,500MW<sup>70</sup>), divided by the then prevailing interconnection rate (\$100/kW). It is expected to be biased downwards because some distributors are reported to not make ACOT payments based on avoided transmission charges. The higher case estimate is 52% and is based on the weighted average of estimated firmness contributions in RCPD periods for different generation types. The base case estimate is 47% and is the mid-point of these values.
- (f) R is the percentage reduction in inefficient generation re-investment as result of the Code amendment. Absent the DGPP provision, distributors subject to price-quality control are not expected to have recoverability for ACOT payments for re-invested distributed generation capacity. For this reason, there is a high likelihood that inefficient re-investment will cease for distributed generation on distributors subject to price-quality control. For distributors not subject to price control, distributed generation owners will no longer be able to require ACOT payments (as a default) based on avoided transmission charges. Distributors might voluntarily make such payments, or re-invest themselves in distributed generation to reduce transmission charges. In light of these factors, the lower case assumes a 75% reduction in inefficient investment (reflecting  $Q_{\text{renew}}$  is for non-exempt distributors).

<sup>70</sup> This includes estimated notionally embedded capacity, the payments for which are expected to be included in the total ACOT payment quantum.

The higher case assumes a 50% reduction (reflecting  $Q_{\text{renew}}$  is for all distributors). The base case estimate is the mid-point between the lower and higher cases.

- C.90 In terms of timing, the benefits from reduced inefficient re-investment are assumed to commence from the time the Code amendment is announced.

#### **Benefit from reduced allocative efficiency losses arising from lower prices for consumers**

- C.91 This section deals with the loss to consumers caused by electricity prices being higher than otherwise in order to fund inefficient ACOT payments.
- C.92 In the May 2016 consultation paper, the Authority estimated that consumers are being required to pay an additional cost of approximately \$25 million - \$35 million per annum to fund ACOT payments that do not produce an associated benefit.<sup>71</sup>
- C.93 While this is a transfer from consumers to some distributed generation and embedded generation owners in the first instance, this will also create efficiency losses by raising electricity prices to end-consumers, thereby distorting their consumption decisions.

#### ***Counterfactual – current TPM***

- C.94 The combination of the current DGPP and the current TPM can increase the price of electricity to consumers, and distort consumption decisions. The Authority expects that the Code amendment would significantly reduce the extent of inefficient payments, and hence reduce the distortion to electricity prices.
- C.95 The specific effect of the DGPP Code amendment on the level of future prices will depend on a number of factors including:
- (a) the nature and extent of existing contracts between distributed generation owners and distributors (noting that the DGPPs set default terms)
  - (b) the extent to which ACOT payments are treated as a recoverable cost for distributors subject to price-quality control
  - (c) the extent to which the DGPPs affect decisions by distributors not subject to price-quality control, for example how they treat requests by prospective distributed generation owners for ACOT payments based on avoided transmission charges
  - (d) pricing decisions by distributors and electricity retailers.
- C.96 For the purposes of this analysis, the Authority has assumed that ACOT payments are reduced by \$25 million to \$35 million per annum going forward. The lower estimate is based on the growth in ACOT payments in the lower South Island and lower North Island between 2008 and 2014. The higher estimate is based on the view that most of the total ACOT payments in these regions (\$37 million in 2014) are not providing a transmission-related benefit.
- C.97 As a point of comparison, an equity research report issued in September 2015 estimated that ACOT revenue for one large participant was around \$25 million per year. The report assessed the loss of the ACOT revenue for that participant as having an 80% likelihood. Given that the report was only referring to one participant, the estimate of \$25 million to

<sup>71</sup> See Electricity Authority, *Review of distributed generation pricing principles, Consultation Paper*, 17 May 2016, paragraph 3.3.21.

\$35 million reduction in ACOT payments across all distributed generation participants appears not unreasonable.

C.98 The Authority estimates the economic benefit (B) as:

$$B = -0.5 \times L \times \Delta P^2 / P \times E$$

Where:

L is the total electricity sales volume in MWh/year

$\Delta P$  is the change in the delivered price of electricity due to the change in ACOT payments, expressed in \$/MWh

P is the average price of electricity excluding ACOT payments in \$/MWh

E is the price elasticity of demand.

C.99 The estimated values for these parameters and the reasoning for each is set out below:

- (a) L is estimated at 43,314,935 MWh on average per year over the 2017-2031 period for all cases. It is based on demand data for 2016 from the 'Energy in New Zealand', published by the Ministry of Business, Innovation and Employment, and then escalated at the rate of demand growth projected by Transpower.
- (b)  $\Delta P$  is estimated by dividing the estimated change in ACOT payments by total electricity sales (L). The lower case estimate is \$0.58/MWh, the base case is \$0.69/MWh, and the higher case is \$0.81/MWh.
- (c) P is estimated at \$184.5/MWh. It is based on data from the 'Energy in New Zealand' publication for 2016, published by the Ministry of Business, Innovation and Employment.
- (d) E is estimated at -0.26, and is the same value as used in the analysis carried out by the Transmission Pricing Advisory Group.

C.100 In terms of timing, 15% of the total annual average benefit is assumed to accrue from 1 April 2018 (when DGPP changes take effect for distributed generation in the LSI region) and the full annual benefits from 1 April 2019. The annual benefit is assumed to remain constant from this date. In reality, there is likely to be more 'shape' to the profile, with rising annual benefits over time. However, the effect on the overall assessment is not expected to be material because the allocative efficiency effect is not a large component of total benefits.

#### Assessed benefits – current TPM

C.101 Table 2 summarises the results of the analysis described above. It shows the estimated economic benefits of the DGPP Code amendment, under the current TPM.

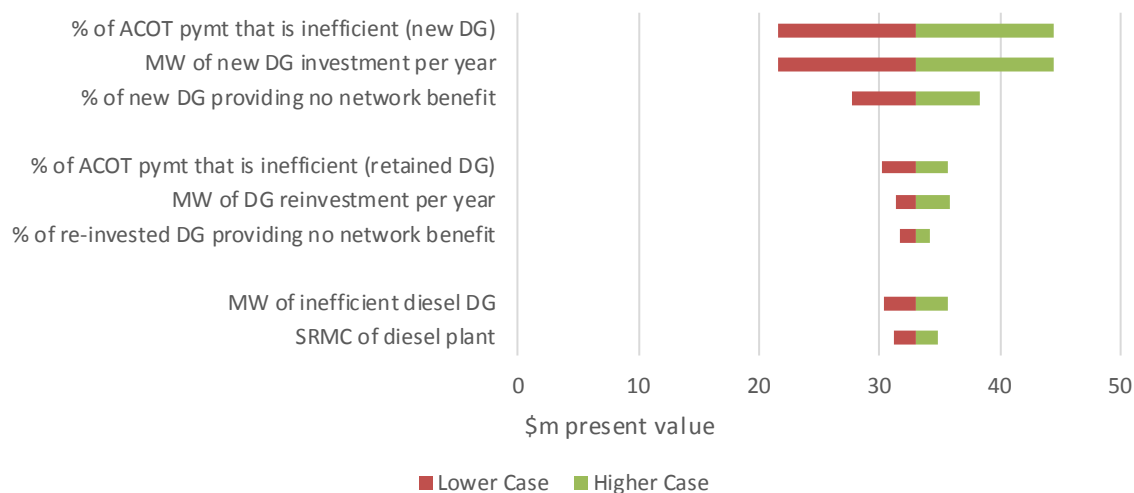


**Table 6: Estimated benefits under current TPM - \$m present value\***

Current TPM	Expected economic benefits \$m PV		
	Lower	Base case	Higher
\$m - present value			
Operations	0.6	4.1	8.4
Reinvestment	1.5	5.5	13.6
Investment	4.7	22.9	56.8
Allocative	0.1	0.1	0.2
<b>Total</b>	<b>6.9</b>	<b>32.7</b>	<b>79.0</b>

\*Excluding unquantified benefits

- C.102 The DGPP Code amendment is expected to yield benefits of approximately \$33 million under the base case. Approximately \$23 million of the benefit is attributable to improved investment decisions in relation to new distributed generation, and the balance of approximately \$10 million is from efficiencies associated with existing distributed generation.
- C.103 Table 2 also shows the estimated benefits under lower and higher cases. These range from approximately \$7 million to \$79 million for total benefits. The range is wide because the values reflect the compounding effect of multiple 'downside' or 'upside' assumptions in each case. For example, the lower case for investment benefits assumes:
- Relatively low total volumes of distributed generation investment
  - A relatively low proportion of total distributed generation investment will provide no material network benefit
  - A relatively low proportion of ACOT payments will be utilised to offset generation or other inefficiencies.
- C.104 Some of these factors are expected to be independent of each other. As a result, the benefit range in practice is likely to be somewhat narrower than the range shown in Table 2. For this reason, the quantitative results are also shown in 'tornado' chart form in Figure 5.
- C.105 This shows the effect on the base case estimate (\$33 million benefit) of varying key individual assumptions. The red bars indicate the effect of adopting the lower case assumption for a given variable, and the green bars the corresponding higher case estimate.

**Figure 5: Sensitivity of base case estimate to key assumptions – current TPM**

As noted above, the DGPP Code amendment is not expected to give rise to any material costs in overall terms. For this reason, the figures in Table 2 and Figure 5 also correspond to the estimated net benefits from implementing the DGPP Code amendment.

C.106 Given that the estimated benefits are \$33 million in the base case, there would need to be a significant increase in total costs for the DGPP Code amendment to yield net costs under the current TPM.

#### Total assessed benefits – prospective AOB-based TPM

C.107 The Authority is currently reviewing the TPM, and considers that there is strong potential for alternative AOB-based TPM options to better promote the Authority's statutory objective. If a new TPM results from the review, the new TPM is likely (among other things) to reduce the misalignment between transmission charges and costs.

C.108 However, even under an AOB-based TPM, the existing DGPPs are expected to create some inefficient incentives. The reasons for this include:

- (a) If a new TPM comes into force, an initial set of AOB transmission charges will be computed to recover the cost of 'eligible assets', being a set of existing transmission assets as defined in the TPM. If the present DGPPs were to apply at that time, distributed generation owners on default terms would be likely to seek ACOT payments from distributors based on avoided *charges*. The basis for calculating avoided AOB charges is not entirely clear, but would presumably involve some assessment of how AOB charges would have differed in the absence of distributed generation. Given that the initial set of AOB charges is to recover the costs for historical transmission investments, it is not clear that ACOT amounts calculated in this way would necessarily provide efficient signals to distributed generation. It is important to note that the position is different for forward-looking grid investments decisions, where the prospect of higher AOB charges would be expected to have positive incentive effects. Furthermore, distributed generation owners would have strong incentives to pursue any potential ACOT claims in relation to the initial set of AOB charges. Conversely, distributors subject to price-

quality control have relatively weak incentives to scrutinise such claims, as long as ACOT payments are treated as a recoverable cost.

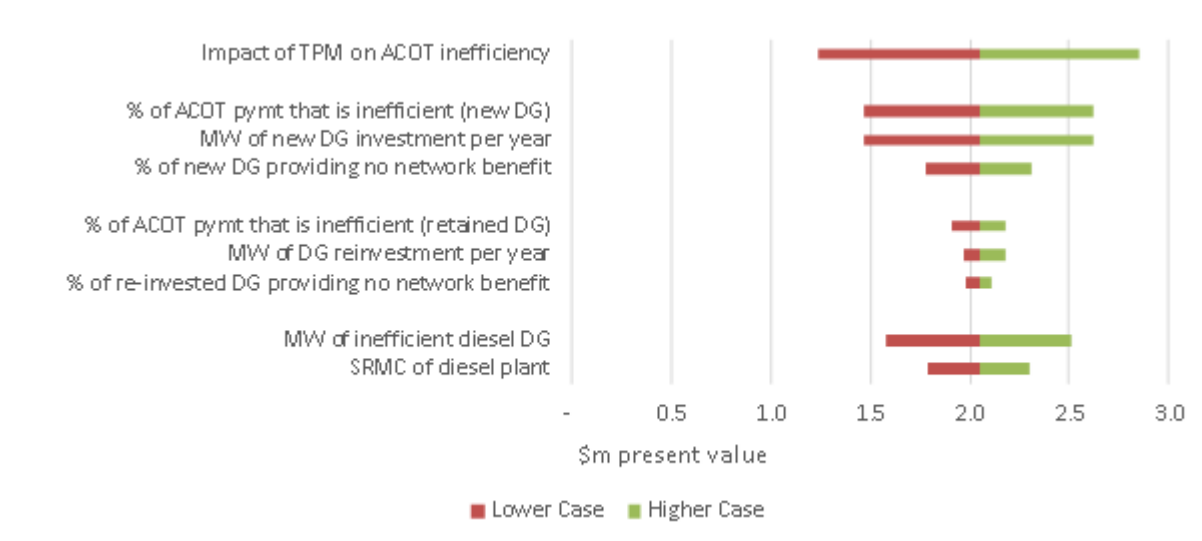
- (b) A material portion of transmission costs are expected to be recovered via a residual charge. This is expected to be based on a measure of capacity, such as historical or lagged gross anytime maximum demand (AMD) (ie net AMD plus distributed generation plus demand response). This measure may need to be reset from time to time to reflect changes in the patterns of grid usage. From a practical perspective, it is difficult to envisage a capacity measure that will completely avoid inefficient incentives for distributed generation – i.e. that will not under- or over-reward distributed generation in some cases, if the existing DGPP continue to apply.
- C.109 While it is not possible to assess with certainty the reduction in ACOT inefficiency from a new TPM, it is unrealistic to expect that it would be 100%. The Authority does, though, expect the degree of improvement to be high. The Authority's TPM proposal is designed to make it difficult for parties to avoid transmission charges through activities such as distributed generation, except where this would reduce future transmission costs. However, some provisions of the proposed new TPM, such as providing for allocation of charges to be updated, might continue to allow customers to avoid transmission charges through activities such as distributed generation in very limited circumstances. There is also the possibility of continuing unpredictable distributor behaviour in making ACOT payments. In recognition of all of these factors, as the base case estimate, the Authority has adopted a scenario where an AOB-based TPM reduces ACOT efficiency losses by 95% as compared to the current TPM.
- C.110 The benefits in the prospective AOB TPM counterfactual are estimated by taking the values under the current TPM, and reducing them by 95% in the base case. The exceptions are the operation and allocative efficiency benefits for the years beginning 1 April 2018 and 1 April 2019. These are not de-rated because the AOB-based TPM would not have any effect until the following year. However, the retention and new investment efficiency benefits are de-rated from the outset. This assumes that expectation of the forthcoming introduction of a new TPM is likely to affect capital expenditure decisions, even though the new TPM is yet to be implemented. This derating is applied because the AOB TPM case assumes there is 100% certainty that an AOB-based TPM will be applied from 1 April 2020. As discussed in paragraphs A.119 to A.123, if a lower probability is assumed, the expected benefits of the DGPP Code amendment would increase, all other factors being equal.
- C.111 The costs associated with implementing the DGPP Code amendment under an AOB-based TPM are not expected to differ materially from those under the current TPM, with one potential exception. The calculation of avoided transmission charges is relatively straightforward under the existing TPM. Under an area-of-benefit based TPM, the assessment process is expected to be more complex. In that respect, adopting the DGPP Code amendment may reduce transactions costs. However, this effect has not been explicitly quantified because there is insufficient information.
- C.112 Table 7 shows the estimated economic benefits of the DGPP Code amendment, under an AOB-based TPM.

**Table 7: Estimated benefits under AOB-based TPM - \$m present value\***

AOB TPM from 2020 \$m - present value	Expected economic benefits \$m PV		
	Lower	Base case	Higher
Operations	0.1	0.6	1.2
Reinvestment	0.1	0.3	0.7
Investment	0.2	1.1	2.8
Allocative	0.0	0.0	0.0
<b>Total</b>	<b>0.4</b>	<b>2.0</b>	<b>4.8</b>

\*Excluding unquantified benefits

- C.113 Under an AOB-based TPM, the DGPP Code amendment is expected to yield benefits of approximately \$2 million under the base case. Approximately \$1 million are attributable to improved investment decisions in relation to new distributed generation, and the balance of approximately \$1 million is from efficiencies associated with existing distributed generation.
- C.114 Table 7 also shows the estimated benefits under lower and higher cases. These range from approximately \$0.4 million to \$5 million for total benefits. As with the analysis under the current TPM, the range is wide because the values reflect the compounding effect of multiple 'downside' or 'upside' assumptions in each case. In practice, the range is likely to be somewhat narrower than that shown in Table 7.
- C.115 For this reason, the quantitative results are also shown in 'tornado' chart form in Figure 6. This shows the effect on the base case estimate (\$2 million benefit) of varying key individual assumptions. The red bars indicate the effect of adopting the lower case assumption for a given variable, and the green bars the corresponding higher case estimate.
- C.116 The chart also shows the effect of varying the assumption regarding the degree to which an AOB-based TPM will reduce ACOT inefficiency. In the lower case, the efficiency reduction is assumed to be 97.5% (bearing in mind that complete elimination of inefficiencies appears implausible). This yields an overall efficiency benefit of \$1.2 million.
- C.117 In the higher case, the efficiency reduction is assumed to be 92.5% (bearing in mind that complete elimination of inefficiencies appears implausible). This yields an overall efficiency benefit of \$2.9 million.

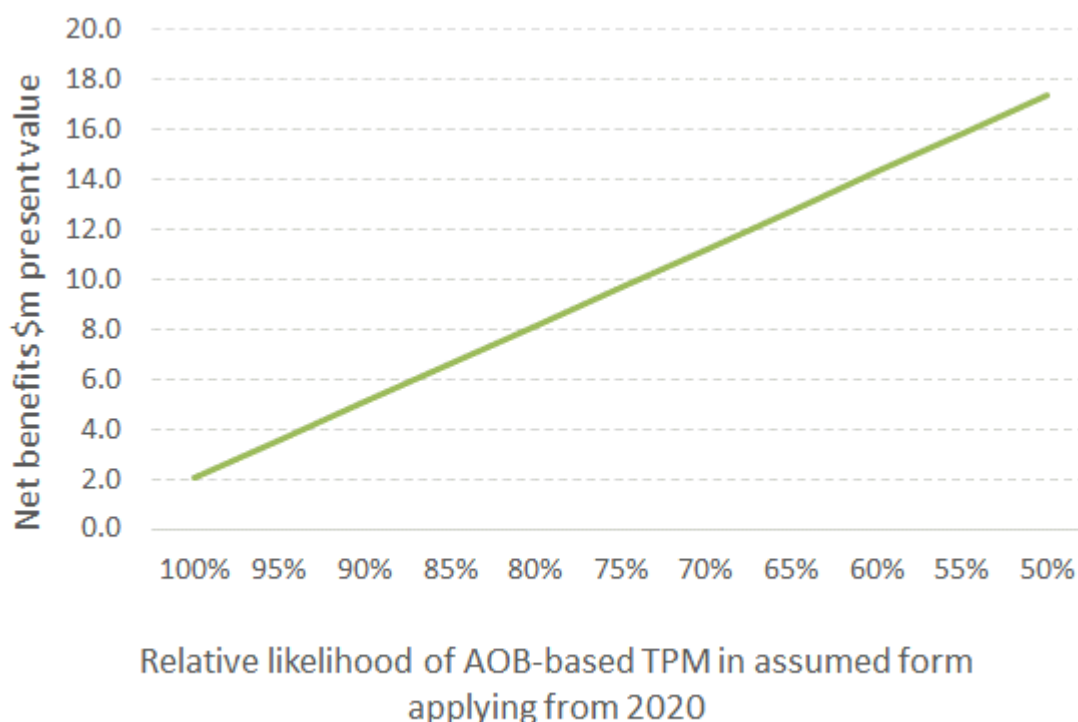
**Figure 6: Sensitivity of base case estimate to key assumptions – prospective TPM**

C.118 As noted above, the DGPP Code amendment is not expected to give rise to any material costs in net terms. For this reason, the figures in Table 7 and Figure 6 also correspond to net benefits.

#### Relative weightings to be applied to counterfactuals

- C.119 While the Authority is reviewing the TPM, and considers that there is strong potential for alternative options to better promote the Authority's statutory objective, it is not certain that the review will lead to adoption of an AOB-based TPM in the assumed form.
- C.120 Given this uncertainty, the Authority has considered how the expected net benefit from the Code amendment would vary with the differing counterfactuals. Figure 7 depicts this information in graphical form.
- C.121 The x-axis shows different assumed levels of likelihood of adopting a new AOB-based TPM. The y-axis shows the net benefits of the Code amendment under the base case assumptions. The net benefits are calculated based on a weighted average of benefits under each counterfactual, multiplied by the likelihood that each will apply.<sup>72</sup>

<sup>72</sup> The relative likelihood of a new AOB-based TPM applying is truncated on the x-axis at 50%. Clearly, the likelihood ranges down to zero – but values lower than 50% are not shown because they do not alter the overall conclusion.

**Figure 7: Net benefits under base case assumptions \$m present value**

C.122 The key observations from this analysis are:

- (a) The highest likelihood that could be assumed for adopting an AOB-based TPM is 100%. At this level, the Code amendment is expected to provide net benefits of \$2 million in present value terms under base case assumptions.
- (b) In reality, the likelihood is less than 100%. As the relative likelihood reduces, the expected net benefit of the Code amendment increases in weighted average terms.

C.123 Accordingly, the Authority concludes that the Code amendment is expected to produce positive net benefits.

#### Comparison of current analysis with May 2016 consultation paper

C.124 The current analysis differs from that in the May 2016 consultation paper in a number of areas. The differences are summarised in Table 8.

C.125 The overall benefits under the current TPM counterfactual are substantially higher than previously estimated. The overall estimated benefit under the AOB counterfactual is similar to that previously estimated. For the AOB counterfactual, the differences in the overall benefit are less marked because there are multiple influences that move in opposite directions.

**Table 8: Comparison of May 2016 and current estimated benefits \$m present value**

May 2016 paper	Expected economic benefits \$m PV		
	Lower est.	Base case	Higher est.
Current TPM	2.0	11.9	21.7
Current TPM two years from April 2017, then area of benefit based TPM*	0.5	2.3	4.2
* excludes some unquantified benefits			
Updated assessment	Expected economic benefits \$m PV		
	Lower est.	Base case	Higher est.
Current TPM	6.9	32.7	79.0
Current TPM until 2020, then area of benefit based TPM	0.4	2.0	4.8

Note: The May 2016 paper set out lower and higher estimates, and did not show a base case per se. The mid-point of the lower and higher estimates is shown in the table as the 'base case' for comparative purposes.

C.126 The key factors that increase the estimated benefits are:

- (a) More detailed consideration of the existing stock of distributed generation has indicated that the potential for inefficient expenditure on the retention of distributed generation was underestimated
- (b) More detailed consideration of the incentives on distributed generation owners has indicated that the previous analysis was unduly conservative regarding the proportion of ACOT payments that would be likely to be used to offset project inefficiencies
- (c) Qualitative benefits that were identified previously have been quantified in the more recent analysis.

C.127 The key factor that reduces the estimated benefits is:

- (a) Reconsideration of the investment benefits in the AOB-based TPM counterfactual suggests that much of the benefit would accrue from the time a new TPM Code

amendment is announced (assuming it is relatively certain in application) – this has the effect of reducing the benefits in the AOB-based TPM counterfactual relative to the current TPM.

### Gross benefits to customers

- C.128 The Authority has also estimated the gross benefits to consumers that would result from the Code amendment.<sup>73</sup> The gross benefits are based on an estimated reduction in annual average ACOT payments of \$25 million to \$35 million per year under the current TPM.<sup>74</sup> The basis for these estimated annual reductions is set out in paragraph C.96. The base case is the mid-point of these estimates.
- C.129 A partial reduction in ACOT payments is expected to accrue from 2018 (when the Code amendment affects distributed generation in the LSI region) and full benefits from 2019 (when all regions are affected). The partial benefit is assumed to be 15% of the full benefit, consistent with the reasoning in paragraph C.100. For the prospective AOB-TPM scenario, the gross benefits have been de-rated in same manner as set out in paragraph C.109.
- C.130 As noted in paragraph 3.59, the Code amendment is expected to strengthen nodal price signals during periods when supply conditions are tight. However, this is not expected to materially affect *average* spot prices. Instead, the Authority expects that spot prices would be higher in periods of tight supply, and lower at other times.
- C.131 The reason for this is that over time, average nodal prices need to be sufficient to cover the cost of supply. Similarly, average nodal prices are not expected to persistently exceed the cost of new supply, as that would attract entry which will in turn dampen nodal prices.

**Table 9: Gross benefits to consumers \$m present value**

Current TPM	Expected economic benefits \$m PV		
	Lower	Base case	Higher
\$m - present value			
Total	212.3	254.8	297.3
AOB TPM from 2020	Expected economic benefits \$m PV		
	Lower	Base case	Higher
\$m - present value			
Total	35.1	42.1	49.2

- C.132 As shown in Table 9, the Code amendment is expected to yield gross benefits to consumers of \$254 million in present value terms in the base case under the current TPM. The lower and higher cases are \$212 million and \$297 million respectively.
- C.133 Under the prospective AOB TPM, the gross benefits to consumers are estimated at \$42 million in present value terms in the base case. The lower and higher cases are \$35 million and \$49 million respectively.

<sup>73</sup> Gross benefits to consumers include wealth transfers. The Authority does not take into account wealth transfers, but it does take into account any efficiency effects that may arise from wealth transfers. Information on gross benefits is included here for information, as it may be a relevant consideration for other policy makers and stakeholders.

<sup>74</sup> There is likely to be a rising profile of benefits over time.



**Appendix D    Concept Consulting Group, Winter capacity margin – potential effect of recent transmission pricing and distributed generation proposals**



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# Winter capacity margin– potential effect of possible changes to transmission pricing and distributed generation pricing principles

Prepared for the Electricity Authority

December 2016



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## Contents

Glossary.....	3
Executive summary .....	4
Base case projection .....	4
Sensitivity case 1 .....	5
Sensitivity case 2 .....	6
Relative likelihood of cases .....	7
1 Introduction .....	9
1.1 Purpose .....	9
1.2 Scope of assessment .....	9
1.3 Treatment of uncertainties .....	10
2 Methodology and base information .....	11
2.1 Transpower’s latest annual security assessment used as base line .....	11
2.2 Period covered by assessment.....	11
2.3 Focus on winter capacity margin .....	12
2.4 Steps in assessment process .....	14
2.5 Base data on capacity of DG and DR resources .....	15
2.5.1 Estimated physical capacity of distributed generation plant .....	15
2.5.2 Estimated capacity of demand response resource .....	17
3 Effect of TPM/DGPP changes on incentives for DG and DR .....	19
3.1 Overview of incentives for DG and DR providers .....	19
3.2 Effect of TPM changes on price signals for operation of DG and DR.....	20
3.3 Effect of DGPP changes on incentives to operate DG.....	21
3.4 Wholesale market incentives.....	22
3.5 Hot water ripple control incentives .....	23
3.5.1 Reduced use of ripple control DR to enable higher provision of IL .....	23
3.6 Overall effect on incentives .....	25
3.7 Scenario descriptions.....	25
3.8 Relative likelihood of scenarios .....	28
4 Capacity margins for 2019 .....	30
4.1 Winter Capacity Margin 2019 - Base case .....	30
4.2 Winter Capacity Margin 2019 - Sensitivity case 1.....	31
4.3 Winter Capacity Margin 2019 - Sensitivity case 2.....	31
4.4 TPM operational review amendments .....	32
4.5 Overall observations regarding winter capacity margin.....	33
5 Indicative impacts on market prices .....	34

5.1	No sustained effect on prices expected.....	34
5.2	Potential transitional scenario .....	34
5.3	Effect on price uncertainty .....	35
Appendix A.	Assumptions.....	36
Appendix B.	How constrained is system capacity in RCPD periods?.....	37
Appendix C.	Strength of incentives to manage peak grid demand.....	39
Appendix D.	Industrial demand response .....	43
Appendix E.	Annual security assessment.....	47

## Glossary

ACOT	Avoided Costs of Transmission
ACOD	Avoided Cost of Distribution
ASoSA	Annual Security of Supply Assessment
DG	Distributed Generation
DGPP	Distributed Generation Pricing Principles
DR	Demand Response
EDB	Electricity Distribution Business (a 'lines' or 'network' company)
FIR	Fast Instantaneous Reserves
Gensets	Diesel generating sets (i.e. reciprocating engine generation plant)
GXP	Grid eXit Point
HAMI	Historical Anytime Maximum Injection (the current parameter used to allocate HVDC costs – see also SIMI)
HWC	Hot Water Cylinder (electrically heated domestic water storage cylinder)
HVDC	High Voltage Direct Current (the inter-island transmission link)
IL	Interruptible Load
IR	Instantaneous Reserves
LNI	Lower North Island
LRMC	Long Run Marginal Cost
LSI	Lower South Island
MW	Megawatt (the unit of measurement of instantaneous power)
MWh	Megawatt-hour (the unit of measurement of energy)
PRS	Price Responsive Schedule
RCP2	Revenue Control Period 2 (the second regulatory period for Transpower)
RCPD	Regional Coincident Peak Demand
Ripple control	A technology used to control the HWCs
SIMI	South Island Mean Injection (the post-2017 parameter used to allocate HVDC costs)
SIR	Sustained Instantaneous Reserves
SRMC	Short Run Marginal Costs
TPM	Transmission Pricing Methodology
UNI	Upper North Island
USI	Upper South Island
WCM	Winter Capacity Margin (a measure used in the ASoSA)

## Executive summary

This report assesses the potential effect on the ability to meet peak electricity demand of possible changes to the Transmission Pricing Methodology (TPM) and Distributed Generation Pricing Principles (DGPP). It also comments on the indicative effect of these potential changes on nodal prices during peak periods.

The assessment focusses on how the changes may impact on the winter capacity margin for 2019 and uses Transpower's most recent Annual Security of Supply Assessment (ASoSA) as the foundation.

We estimate the installed capacity (and likely capacity contribution) of distributed generation (DG)<sup>1</sup> and available demand response (DR) under the status quo arrangements. We then assess how the operation of DG and DR is likely to change, based on the incentives on providers that would be expected to apply under the TPM/DGPP changes if they were implemented.

We note there is uncertainty in relation to some key issues. In particular, there is limited information about the volume of DR resource that is currently active in peak demand periods. There is also uncertainty about how some parties may respond to the TPM/DGPP changes, especially electricity distribution businesses (EDBs) in relation to ripple control of water heating.

For these reasons, we have developed a base case which represents the outcome we consider to be most likely. We have also considered two sensitivity cases that reflect different assumptions. We consider these sensitivity cases to represent less likely outcomes than the base case.

### Base case projection

In this case, we expect the capacity contribution from DG plant to be largely unchanged, because nodal prices during tight system periods are likely to exceed the short run marginal costs (SRMC) of operation. The exception is diesel-fuelled DG plant, which has a higher SRMC than anticipated nodal prices during most peak periods. The base case projects a reduction in capacity contribution for this plant of 117 MW.

We have examined the demand response of large industrial users to both current transmission-charge signals, and nodal prices. Based on this information, we project a reduced DR contribution from this group of 50 MW. We also project a 50 MW reduction in DR from commercial and smaller industrial users.

In relation to ripple control of hot water heating, we project a reduced DR contribution of 170 MW (around 25% of current DR contribution from ripple control). Based on market data, we expect this increased hot water heating load to be offered into the reserves market as interruptible load, freeing up some generation. As a result, we project a net reduction in capacity contribution of 50 MW from reduced use of hot water ripple control.

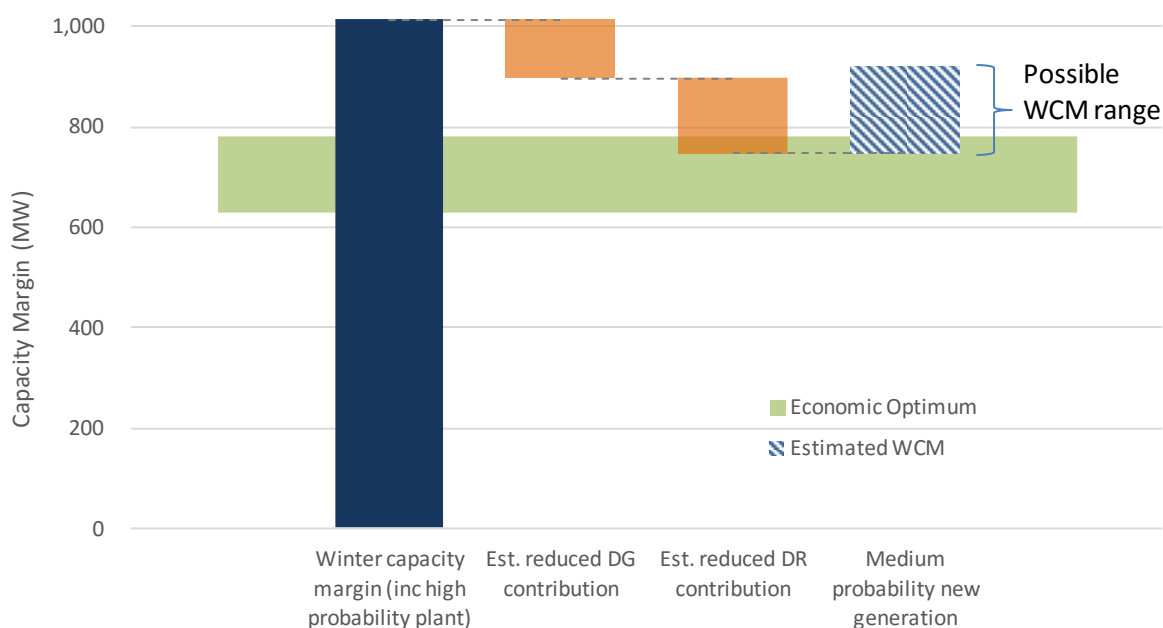
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<sup>1</sup> We use the term 'DG' here, but more correctly, we are looking at physically embedded and notionally embedded generation. We are including the latter because notionally embedded generation is likely to receive Avoided Costs of Transmission payments (ACOT).

In aggregate, these effects would reduce the projected winter capacity margin for 2019<sup>2</sup> based on existing and ‘high probability’<sup>3</sup> plant by around 270 MW, to a new level of 750 MW, as shown by Figure 1. This is within the estimated optimum economic range for the winter capacity margin.

If prospective new plant investment categorised as ‘medium probability’<sup>4</sup> is included, the winter capacity margin rises to around 920 MW, which is above the economic optimum range.

**Figure 1 - Base case projection for 2019 winter capacity margin**



### Sensitivity case 1

We have considered a sensitivity case in which there is a 50% reduction in the net DR contribution from ripple control, and all other assumptions are unchanged. While we regard this sensitivity case as being less likely than the base case, we recognise that there are uncertainties about the amount of ripple control DR that is available, the incentives operating on parties who control its use, and interactions between DR and the reserves market.

Unlike DG owners, EDBs who exercise operational control of ripple relays do not have a clear financial incentive to respond to nodal energy prices at present. To the extent that ripple control can yield greater value for energy DR purposes in the future, a tightening of the incentive linkages between EDBs and other parties such as users/aggregators/retailers would be expected to develop. However, that may not have occurred sufficiently by 2019, given the complex nature of the issues and number of parties involved.

In aggregate, these effects would reduce the projected winter capacity margin for 2019 by around 585 MW. As shown by Figure 2, the resulting 2019 winter capacity margin based on existing and

<sup>2</sup> CY 2019 is considered because the earliest that the assumed TPM changes could have effect is the September 2018 to August 2019 capacity measurement period. The DGPP changes are assumed to take effect earlier, but these do not affect DR and we expect them to have a relatively modest effect on DG in the base case.

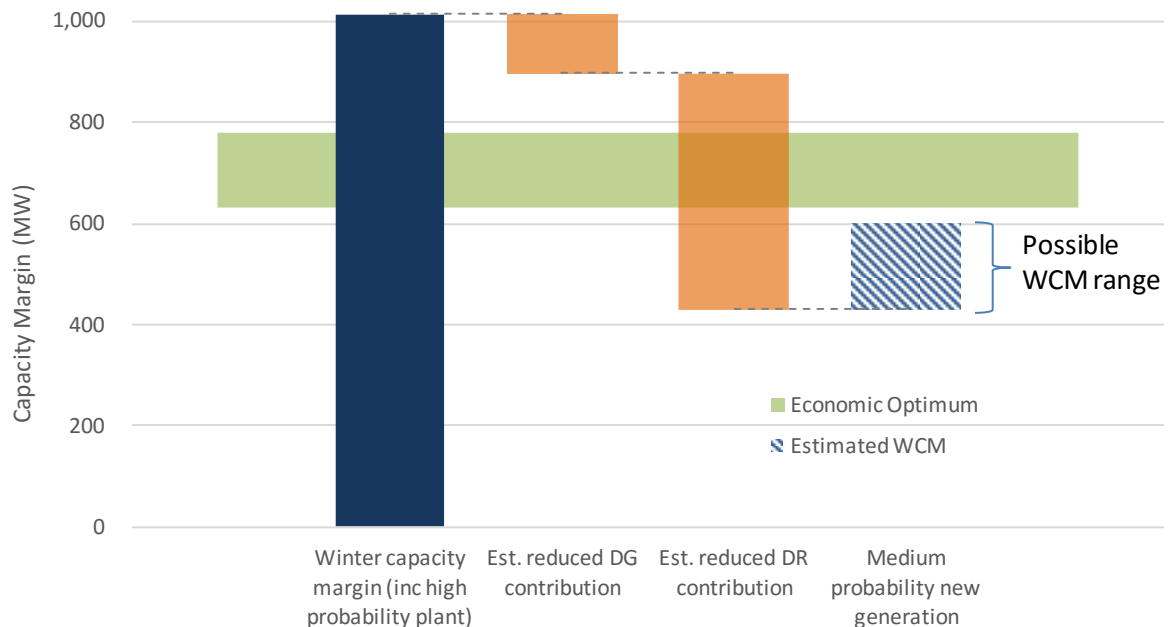
<sup>3</sup> The ASoSA discusses potential new generation plant that is expected to be available on the system by 2019. ‘High probability’ generation includes plant that has a 75% likelihood of proceeding according to responses to an industry survey.

<sup>4</sup> ‘Medium probability’ generation includes plant that has a 50% likelihood of proceeding based on industry survey data.



'high probability' plant would be around 430 MW, which is well below the assessed economic optimum range. If prospective new plant investment categorised as 'medium probability' is included, the resulting winter capacity margin is around 600 MW, which is somewhat below the economic optimum range.

**Figure 2 - Sensitivity case 1 projection for 2019 winter capacity margin**



## Sensitivity case 2

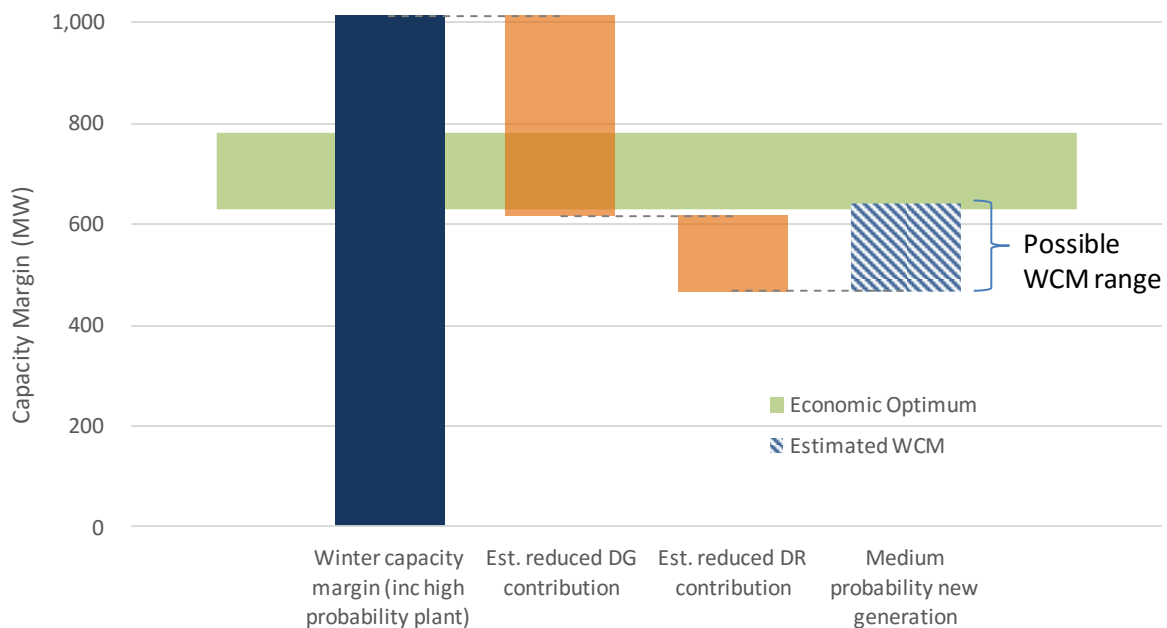
Although we expect the capacity contribution from most DG plant to be unchanged, we have considered a sensitivity case where a sizeable number of non-diesel DG plants restrict their generation levels during tight system periods (foregoing immediate spot revenues), in the belief this will yield future net benefits, such as higher payments for transmission support from Transpower.

In this case, we assume a 400 MW reduction in the firm capacity contribution from DG. This is roughly twice the observed difference between average DG output in RCPD periods, and the 100 hours of lowest DG contribution across a year.<sup>5</sup>

In aggregate, these changes would reduce the projected winter capacity margin for 2019 by around 550 MW. As shown by Figure 3, the resulting 2019 winter capacity margin based on existing and high probability plant would be around 470 MW. This is well below the assessed economic optimum range. If prospective new plant investment categorised as 'medium probability' is included, the resulting winter capacity margin would be around 640 MW, which is within the economic optimum range.

<sup>5</sup> This is based on DG for which half-hourly output data was available, and excludes some smaller scale plant. See Figure 6 for more information.

Figure 3 - Sensitivity case 2 projection for 2019 winter capacity margin



### Relative likelihood of cases

We regard the base case as being the most representative of expected outcomes for the reasons set out in section 3.8. In summary, these are:

- Financial incentives have been robust predictors of DG behaviour to date. Under a change from RCPD to nodal price incentives<sup>6</sup>, we expect most DG to continue to be better off from operation during tight system periods.
- Aside from the interruptible load substitution issue addressed in the base case, there is no clear short-term benefit for EDBs (or their customers) from a widespread and abrupt change to ripple control practices.

Having said that, we recognise there are uncertainties around some issues. Furthermore, decision-makers may make short-term choices which are not anticipated, because they don't fully understand the TPM/DGPP changes.<sup>7</sup> For these reasons, we considered the sensitivity cases noted above.

We note also that other possible outcomes could arise. These could result in a more modest degree of change to capacity margins than the base case (especially if nodal prices rise sufficiently to elicit operation of diesel DG).

Alternatively, the degree of change could be more marked, such as some combination of sensitivity cases 1 and 2. Having said that, we believe there are counteracting influences that make a combination of cases 1 and 2 very unlikely. Put simply, if demand response was much reduced (as in case 1), the opportunity costs and risks for DG owners of not operating in peak periods would be

<sup>6</sup> We note that regions with impending transmission upgrades are expected to face an incentive to delay (or avoid) these transmission upgrades due to the prospective increase in the AOB charges they will face if an upgrade proceeds.

<sup>7</sup> Such as a misperception held by some parties that the TPM changes would remove all incentives to manage peak grid demand growth.

even higher, making it less likely that widespread withdrawal of DG would occur. Similarly, if there was widespread withdrawal of DG in peak demand periods (case 2), it appears less likely that EDBs would fail to respond if requested by the system operator to initiate ripple control of water heating load.

# 1 Introduction

## 1.1 Purpose

This report has been prepared by Concept Consulting Group Limited (Concept). It assesses whether potential changes to the current Transmission Pricing Methodology (TPM) and Distributed Generation Pricing Principles (DGPP) (together referred to as the TPM/DGPP changes) could materially impact upon the ability to meet peak demands for electricity.

Under the status quo Transpower recovers most its revenue from the interconnection charge. This charge is based on a party's Regional Coincident Peak Demand (RCPD), which is a measure of its net demand during the top 100 regional peak demand periods. Embedded generators that generate during RCPD periods will reduce the interconnection charge for the host EDB.

The current DGPPs place a default requirement on EDBs to pay DG for avoided transmission costs. In practice, most EDBs interpret this as an obligation to make avoided cost of transmission (ACOT) payments based on avoided transmission charges (noting that DG operation may or may not reduce transmission costs).

We have assumed the following in relation to the TPM/DGPP changes:

- TPM – the interconnection and high voltage direct current (HVDC) charges in the current TPM would be replaced. Instead a combination of an area-of-benefit charge, a capacity-based residual charge and (potentially) a long run marginal cost charge would apply. The TPM changes would be broadly as described in the Issues Paper released by the Electricity Authority (Authority) in May 2016.<sup>8</sup> Our assessment is based on these proposals, except that we have assumed a commencement date for the new TPM of 1 April 2020 (rather than 1 April 2019 as set out in the Issues Paper).
- DGPP – for new DG, there would no longer be a default requirement for EDBs to make any ACOT payments. Instead, new DG owners could negotiate with Transpower to provide transmission-substitute services, where DG provides an efficient alternative. For existing DG, the Authority would receive advice from Transpower on which DG (individually or collectively) is required to meet the grid reliability standards. The Authority would decide, based on Transpower's advice, which distributed generation would qualify for ACOT payments under the default terms. DG that did not qualify would lose eligibility under the default terms, and such changes would take effect from 1 April 2018 (for DG in the Lower South Island), 1 October 2018 (Lower North Island), 1 April 2019 (Upper North Island) and 1 October 2019 (Upper South Island). The DGPPs would be further reviewed as appropriate.<sup>9</sup>

## 1.2 Scope of assessment

The report considers security issues at the aggregate system level. The likelihood and magnitude of any more-localised security effects, such as at a regional level, lie outside the scope of this report.

More specifically, the assessment considers:

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<sup>8</sup> See Electricity Authority, *Transmission Pricing Methodology: Issues and proposal, Second issues paper*, 17 May 2016.

<sup>9</sup> See Electricity Authority, *Review of distributed generation pricing principles, Consultation paper*, 17 May 2016. We understand that the Authority is considering a proposal that is based on 'Alternative 3' in section 4.6 of the paper. We also understand that the Authority is not planning to make any changes at this time to the connection services provisions of the DGPPs.

- The potential for reduced demand response activity (DR) (e.g. ripple control of hot water cylinders) during peak demand periods, due to the effect of the assumed TPM changes on incentives to undertake DR activity.
- The potential for reduced contribution from distributed generation (DG) during peak demand periods, due to a reduction in Avoided Cost of Transmission (ACOT) payments under the assumed TPM and DGPP changes.

In all cases, the assessment is relative to a status quo where the TPM/DGPP changes do not come into operation. However, the status quo does include the changes to transmission pricing that were approved as part of the TPM operational review in 2015.

### 1.3 Treatment of uncertainties

As discussed later in this report, there are information limitations that create uncertainty around key issues. The limitations include:

- There is no comprehensive recent information available on the capacity of hot water heaters subject to ripple control, and the amount of DR that this typically provides in tight system or peak demand periods.
- There is limited information on the DR provided by industrial and commercial users - the main data available being bids in the Price Responsive Schedule (PRS).
- The uncertainty in the capacity and type of DG connected to the system. This is due to some plant not being reported in various surveys and public databases, and also due to limited information about contractual embedding agreements which may be relevant to operational incentives.
- A lack of operational data for some DG, making it harder to determine the operation of some plant (i.e. is it typically currently operating during peak demand periods or not?) under the status quo.
- Mixed or unclear incentives on some parties – especially in relation to operation of ripple control for hot water heaters.

To address these uncertainties, this report uses scenarios that draw on the range of available information sources that have been identified. The scenarios are intended to span the range of possible outcomes that can plausibly be expected. The report discusses the reasoning for the scenarios, and assesses their relative likelihood in qualitative terms.

## 2 Methodology and base information

### 2.1 Transpower's latest annual security assessment used as base line

The Electricity Participation Code requires that Transpower publish a medium to long-term security of supply assessment at least annually. The most recent Annual Security of Supply Assessment (ASoSA) was published in February 2016.<sup>10</sup> This was developed by Transpower before the Authority published the TPM/DGPP proposals in May 2016.

The ASoSA projects the predicted system security margins for future years, and compares these projections to security of supply standards that have been previously developed by the Authority.

In this report, we assess the potential effect of the TPM/DGPP changes on the predicted system security margins in Transpower's latest ASOSA. These revised security margins are then compared to the assessed economic optimum ranges for security margins.

### 2.2 Period covered by assessment

The most recent ASoSA covers the period 2016-2025. For our assessment, we have focused on the 2019 calendar year because:

- Should a new TPM come into effect on 1 April 2020, there will be no RCPD-based transmission price signal to manage peak demand during the winter of 2019 even though the existing<sup>11</sup> TPM will still apply. This is because RCPD charges for the 2019 transmission year will be based on participant behaviour in earlier periods, and any behaviour in 2019 itself will not affect future transmission charges.<sup>12</sup>
- A new TPM is expected to provide incentives to manage peak grid demand via the prospective effect on area of benefit (AoB) charges, and/or an LRMC-based charge. However, information to facilitate parties' assessment of future AoB charges may not yet be available in 2019,<sup>13</sup> and any LRMC charge will not take effect until 2020 at the earliest.
- While the DGPP changes would be expected to affect some regions from April 2018, for the reasons discussed later, we do not expect this to have a material impact on operational incentives for most DG plant-types.
- For later years, a greater range of uncertainties unrelated to the TPM/DGPP changes come into play – such as the underlying level of demand growth, decisions about commissioning or decommissioning of generation plant etc.
- Market participants are likely to take account of projected changes in the system margin. For example, a predicted tightening of the system margin is likely to make investment in generation or DR more attractive, and vice versa. However, there can be a lag before such responses can occur, because of the time needed to bring new resources into operation. Accordingly, nearer term security impacts are likely to be more material than longer term effects.

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<sup>10</sup> See <https://www.systemoperator.co.nz/sites/default/files/bulk-upload/documents/SoS%20Annual%20Assessment%202016.pdf>

<sup>11</sup> Strictly, it is the existing TPM including changes to Transpower's charges that will occur as a consequence of the 2015 operational review.

<sup>12</sup> The capacity measurement period, upon which charges for the 2020 transmission year would be based, will run from 1 September 2018 to 31 August 2019 for the Upper South Island region. For pricing in other transmission regions, the measurement period excludes the November – April months in this period.

<sup>13</sup> For the reasons discussed in section 3.2.

## 2.3 Focus on winter capacity margin

The ASoSA considers security from the perspective of:

- The Winter Capacity Margin (WCM) – the ability to serve demand during short periods when the system is tight - such as peak demand periods and/or when an unexpected loss of major generation/transmission capacity occurs and
- The Winter Energy Margin (WEM) – the ability to meet demand during a prolonged drought or similar supply contingency.

In our view, the assumed TPM/DGPP changes are unlikely to have any material impact on the projected WEM because:

- Where DR is currently operated to reduce demand at regional coincident peak periods, this generally results in load shifting to off-peak periods, with little or no change in total energy demand.
- To the extent that DR does occur in energy shortage periods, it is mainly driven by nodal prices (or arrangements linked to those prices) – and these incentives are not expected to be reduced by the TPM/DGPP changes.
- Most DG has relatively low short run marginal costs (SRMCs). The operation of this plant during periods of tight energy supply (such as ‘dry years’) is therefore unlikely to be affected by the assumed TPM/DGPP changes, given that nodal prices are expected to be elevated during such periods.

For these reasons, this analysis focuses on whether the TPM/DGPP changes are likely to affect the WCM.

The WCM is calculated according to a formula set out in the Security Standards Assumptions Document (SSAD)<sup>14</sup> which determines the extent to which expected North Island capacity, supported by available South Island capacity, exceeds expected North Island demand during winter peak periods. A positive margin is required to cover unexpected events such as generation plant outages, transmission outages, or unusually high demand.

With a high margin the risk of shortages during peak periods will be low, but there will be a cost from having additional generating plant available. With a low margin, there will be reduced generating plant costs, but a higher risk of shortages. The Authority has determined that the optimum trade-off between generating plant costs and shortages is likely to be when the WCM lies between 630 MW and 780 MW<sup>15</sup>.

If WCM falls below this economic optimum range, there will be an increased likelihood that peak demand will not be fully satisfied. During these periods, voluntary DR and/or reduced operating reserves may be required,<sup>16</sup> or in the extreme, forced power outages. For example, if the actual WCM is 690 MW, an energy or reserves shortfall (as a result of capacity shortage) would be expected to occur in 22 hours per year on average.<sup>17</sup>

A concern could arise if the contribution of DG and/or DR during tight system periods were to be materially reduced because of the TPM/DGPP changes, to the extent that the WCM was to fall below the optimum range.

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<sup>14</sup> See <https://www.ea.govt.nz/operations/wholesale/security-of-supply/security-of-supply-policy-framework/security-standards-assumptions/>

<sup>15</sup> See [www.ea.govt.nz/our-work/consultations/sos/winter-energy-capacity-security-supply-standards/submissions/](http://www.ea.govt.nz/our-work/consultations/sos/winter-energy-capacity-security-supply-standards/submissions/)

<sup>16</sup> Increasing the likelihood of load shedding being required to cover a contingent event

<sup>17</sup> See [www.ea.govt.nz/dmsdocument/14134](http://www.ea.govt.nz/dmsdocument/14134)

It is important to recognise that in New Zealand, tight system periods are not always associated with high national demand (let alone regional coincident peak demand periods). Figure 4 shows nodal prices (an indicator of system stress) and national power demand at the grid level. Many of the trading periods with higher prices are unrelated to peak demand, and occur due to supply-related factors, such as the unavailability of large thermal units.

**Figure 4 - Nodal prices and national demand – 2015**

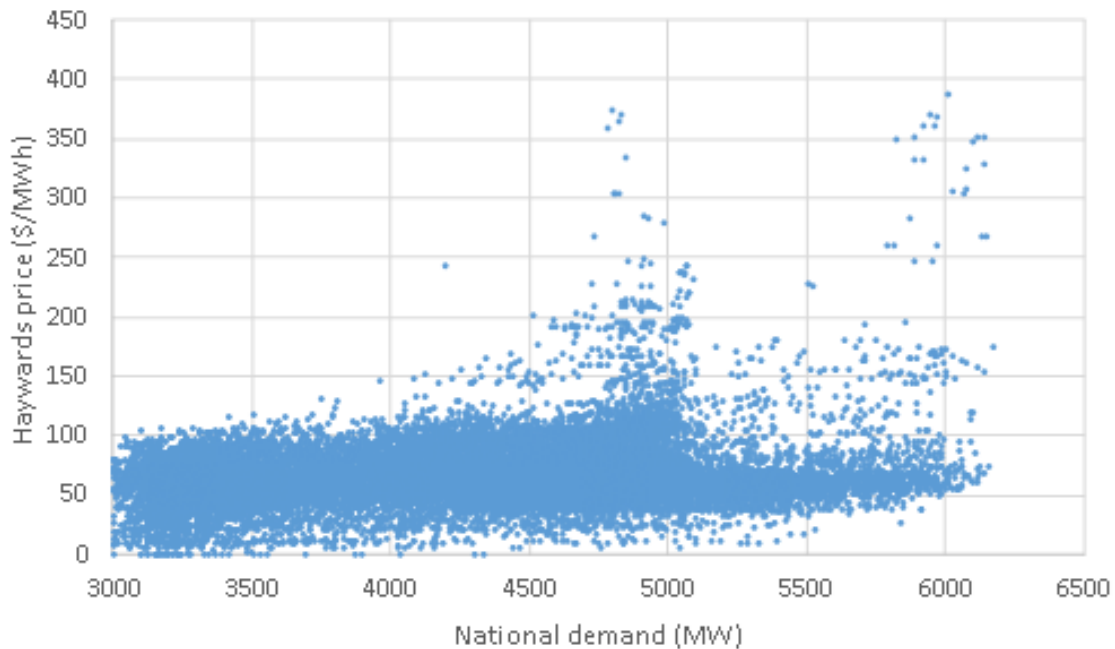
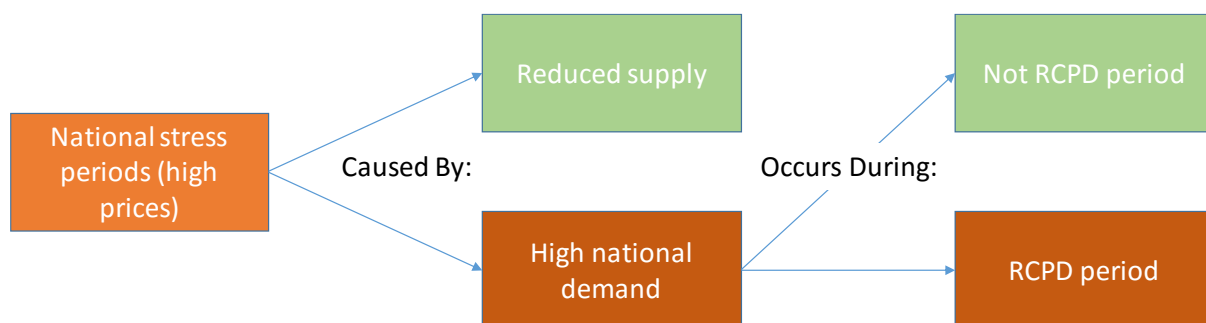


Figure 4 shows that nodal prices were generally higher when national demand was elevated. However, it also shows that tight system periods (indicated by the highest nodal prices) were not always associated with peak national demand periods. Furthermore, RCPD periods do not strictly coincide with times of peak national demand<sup>18</sup> – especially for the Lower South Island (LSI) and Upper South Island (USI) transmission regions (see Appendix B for more information). Figure 5 illustrates the relationship between these effects.

**Figure 5 - Cause of high nodal prices**



<sup>18</sup> National peak demand typically occurs due to a cold weather event in the upper North Island, which may not coincide with cold weather in other parts of the country. Regional peak demand can also occur during periods of high irrigation load, or other region specific events.



Figure 6 presents analysis undertaken by the Authority that shows DG output<sup>19</sup> at different levels of national demand.<sup>20</sup> Three things are apparent from the graph:

- DG output increases only slightly as national demand increases. The average generation during high demand periods is about 200 MW higher than during low demand periods. This suggests that there is about 200 MW of generation that currently responds to changes in demand.
- There is always at least 400 MW of DG in operation. This suggests that there is about 400 MW of embedded generation that always generates, irrespective of national demand
- There is a large amount of ‘noise’ at all demand levels. Generation varies by about 400 MW at all levels of national demand.

**Figure 6 - Embedded generation and total generation**

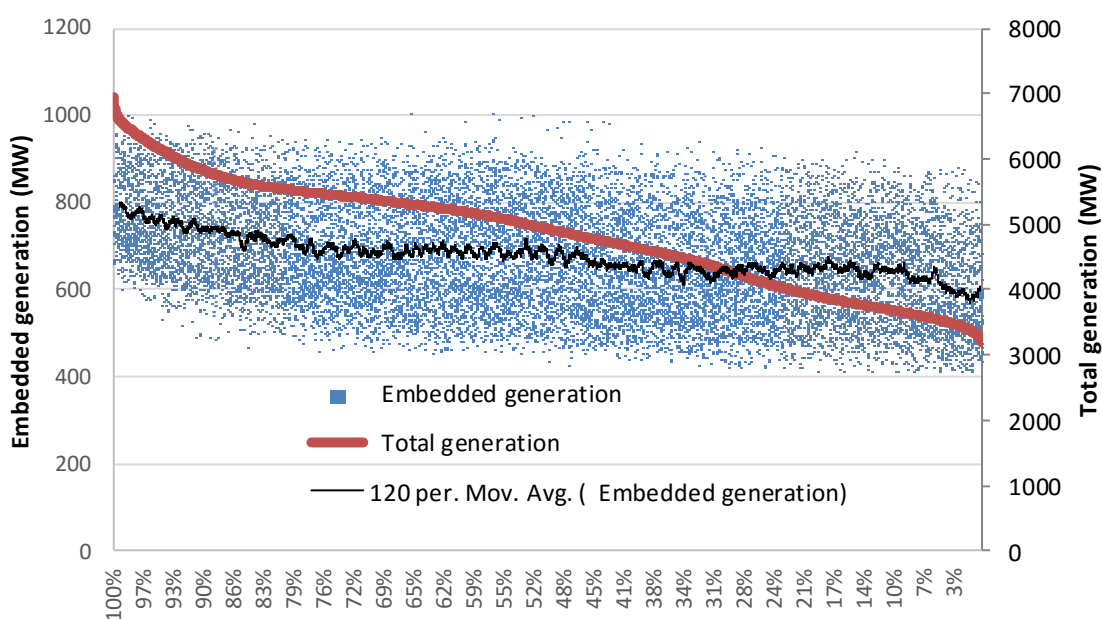


Figure 6 also shows that DG’s proportion of total generation generally *decreases* during high demand periods.

## 2.4 Steps in assessment process

The approach to assessing the incremental impact of the TPM/DGPP changes on the WCM is as follows:

1. Assess the available DG and DR capacity – categorised by type of DG plant or DR provider
2. Assess the extent to which each DG or DR type is expected to be operating during RCPD periods (i.e. the status quo)
3. Assess the extent to which RCPD periods coincide with times of system stress
4. Assess the extent to which each DR or DG type is likely to change operational behaviour from 2019, including allowances for the following:

<sup>19</sup> This graph only includes embedded generation for which half-hourly data is available. The maximum generation is just over 1,000 MW, compared to a total installed capacity of 1,500 MW (see section 2.5.1.)

<sup>20</sup> Strictly speaking, this is national generation, which is national demand plus losses.

- a. whether it is physically able to change behaviour (e.g. is DG 'inflexible' plant or not); and
  - b. how the incentives on decision makers may change under the TPM/DGPP changes.
5. Develop base case, and sensitivity scenarios for the volume of DG and DR that may not contribute reliably in tight system periods based on the information from steps 1-3, and deduct a corresponding capacity allowance from the projected WCM for 2019 in Transpower's latest ASoSA
  6. Compare the resulting adjusted WCM to the economic optimum range.

We note that in relation to steps 4 and 5, we have not undertaken a full probabilistic estimation of projected and economic capacity margins. Ideally, that approach would be preferred, as it would better reflect the relationships (or lack thereof) between major variables. However, there is limited information in some key areas (e.g. ripple control) and a full estimation approach would significantly broaden the scope of this analysis.

Finally, in addition to the above analysis on capacity margins, we also provide some commentary of the potential impact of modified DG and DR behaviour on wholesale electricity prices.

## 2.5 Base data on capacity of DG and DR resources

The estimated available capacity for DG and DR is discussed below.

### 2.5.1 Estimated physical capacity of distributed generation plant

We estimate the DG installed capacity to be approximately 1,500 MW. This includes generation plant connected to distribution networks, and so-called 'nationally embedded' generation. The latter plants are physically connected to the transmission network, but receive some form of payment to reflect the transmission charges that would be avoided if plant was physically embedded in the adjacent distribution network.

This nameplate capacity estimate has been compiled from a variety of sources (primarily the Authority's 'existing generation' data set, and the survey<sup>21</sup> of DG). As discussed in Appendix A, the assessed capacity contribution for some DG is de-rated below the nameplate capacity. For example, the ASoSA treats wind generation's capacity contribution as 25% of its nameplate capacity. Similarly, some hydro plants are subject to specific deratings, which in aggregate lower hydro DG's assessed capacity contribution by 98 MW compared to nameplate capacity.

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<sup>21</sup> This survey, which was undertaken as part of the Authority's 2015 DGPP work, sought information about the individual embedded generation plant within each EDB.

**Table 1 - Summary of the DG nameplate capacity**

Distributed generation		Estimated Installed Capacity			Main drivers of plant SRMC
		MW	Inflexible	Flexible	
Thermal	Diesel	117		117	Operating costs and fuel costs
	Gas	77	77		Operating costs and gas costs
Hydro	Storage	566		452	Water opportunity cost & operating costs
	Run of river		113		Operating costs
Wind		364	364		Operating costs
Cogen		146	146		Generation-related operating costs
Geothermal		145	145		Operating costs
PV		40	40		Operating costs
Bio	(landfill gas)	56	56		Operating costs
<b>Totals</b>		<b>1,510</b>	<b>941</b>	<b>570</b>	

The 1,500 MW total nameplate capacity presented in this table may appear to conflict with peak distributed generation of just over 1,000 MW shown in Figure 6. However, this table includes *all* distributed generation, not just that which has half-hourly generation data. Additionally, the peak value in Figure 6 is a coincident peak value, rather than a sum of individual peaks.

There is some uncertainty in this DG base data, as the various sources appear to differ in relation to coverage, and have some data inconsistencies. Examples of these inconsistencies include:

- Plant that is notionally embedded but not physically embedded may appear in some but not all sources
- Uncertainty about whether some plant is embedded or not (e.g. Wheao is shown as grid-connected in the Authority data but is shown as embedded in Transpower’s information)
- About 14 MW of capacity appears in the Authority’s ‘Existing generation’ data set, but is not in the survey
- About 11 MW of capacity appears in the survey, but is not in the Authority ‘Existing generation’ data set
- Nameplate ratings that appear to be inconsistent (e.g. Mill Creek wind farm has an ‘operating capacity’ of 71.3 MW in the Authority ‘Existing generation’ data but has an installed capacity of 59.8 MW; and Matahina is shown as 80 MW capacity in some data, but is shown in the ‘Existing generation’ data as 72 MW).

While we have accounted for discrepancies where they were identified, some uncertainty in the data remains. The issue of identifying plant that is notionally embedded is likely to be the largest area of uncertainty, because these contracts often involve larger plant (i.e. many tens of megawatts). It includes plant such as Mangahao<sup>22</sup> (42 MW), Waipori (83 MW), Matahina<sup>23</sup> (80 MW) and Aniwhenua (25 MW)<sup>24</sup>. The three latter embedding arrangements are achieved through

<sup>22</sup> See page 39 of Electra’s 2016 Asset Management Plan <http://electra.co.nz/our-company/disclosures/>

<sup>23</sup> See [https://www.transpower.co.nz/sites/default/files/uncontrolled\\_docs/Matahina-Aniwhenua-PDA-supporting-information.pdf](https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Matahina-Aniwhenua-PDA-supporting-information.pdf) and [https://www.transpower.co.nz/sites/default/files/uncontrolled\\_docs/Matahina-Aniwhenua-PDA-external-report.pdf](https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Matahina-Aniwhenua-PDA-external-report.pdf)

<sup>24</sup> These plants are included in the ‘storage’ hydro in Table 1

Transpower's prudent discount arrangements. The nature of the Mangahao contract is unclear but Electra's Asset Management Plan states explicitly that:

*"The Mangahao Power Station is the subject of a Generation Connection Agreement... with the purpose of sharing transmission benefits resulting from the demand reduction at the Grid Exit Point. Operational control of the station has not changed except that generation is focused where possible around regional co-incident peaks."*

This notionally embedded plant is relevant because they are understood to currently receive a financial benefit arising from operation during RCPD periods. Therefore, the removal of RCPD may affect plant operation.

## 2.5.2 Estimated capacity of demand response resource

Electricity users may reduce their demand in response to RCPD signals, and/or nodal prices. Table 2 sets out the estimated capacity of active DR that is estimated to react to RCPD signals under the status quo.

We emphasise that there is a degree of uncertainty in this estimate, as there is little visibility of load control, apart from load that is explicitly bid in the Price Responsive Schedule (PRS) in the spot market. Even the PRS data is challenging to assess because only the behaviour can be observed (i.e. responses, and concurrent prices and demand), not the intent behind the behaviour.

The use of ripple control on hot water cylinders is expected to be the dominant source of DR. The 700 MW of ripple controlled load is the estimated capacity believed to be available.

The estimate is based on the 2006 'Existing Capability Survey' undertaken by the then Electricity Commission, and has been cross-checked using a range of methods that all produce similar results:

- a 'bottom-up' estimate based on housing stock, ratio of electric to gas water heating (and ripple control penetration), and an assessment of the diversity factor arising from hot water usage patterns;
- an extrapolation from Orion data to New Zealand as a whole, based on ICP numbers; and
- inspection of the observed changes in demand at GXPs with high residential customer numbers during RCPD periods.

The estimate for DR by grid-connected major users is based on analysis of PRS and load data. Further information on the derivation of the estimate is set out in Appendix D.

The Other Business Users category of DR refers to situations where users reduce their power demand in RCPD periods, for example by temporarily turning off some chillers for a cool store.

We are not aware of any specific data on this category of DR. However, it appears unlikely to exceed the change in DR of grid-connected major users that respond to RCPD signals. This is because other business users would typically face higher transaction costs (due to their relatively smaller size and fixed nature of many costs of setting up DR). In addition, the situation where a business user has diesel-fired generation for 'DR' purposes has been estimated separately in Table 1. For the purposes of this assessment, we have assumed that the change in DR from other business users in response to RCPD signals is similar in magnitude to that of grid-connected major users.

*Table 2 - Summary of the assessed DR capability potentially affected by the TPM/DGPP changes*

<b>Demand response</b>		<b>Estimated Capacity (MW)</b>
Ripple control	Hot Water Cylinders	700 <sup>25, 26</sup>
Grid-connected Major Users	Industrial	50
Other Business Users	Various load types (e.g. cool stores)	50
<b>Totals</b>		<b>800</b>

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<sup>25</sup> Of which, roughly 25% are thought to have frequency sensitive relays.

<sup>26</sup> This is the estimated 'after diversity' capacity (the amount that is expected to be used at any one time during peak periods) and is subject to the scenario assumptions below.

### 3 Effect of TPM/DGPP changes on incentives for DG and DR

This section discusses the incentives to invest in, and operate DG and DR, and how they are likely to be affected by the TPM/DGPP changes. We also consider other non-transmission related price signals influencing the DG and DR behaviour, as these may be relevant when assessing overall impacts.

#### 3.1 Overview of incentives for DG and DR providers

The existing and possible new price signals affecting DG and DR are summarised in Table 3 below. The extent to which these signals may influence decision-makers is discussed in a subsequent section.

*Table 3 – Price signals influencing DG and DR during peak demand periods*

Peak demand signal	Timing	Strength of the signal or incentive <sup>27</sup>	Comment on incentives that arise
RCPD	Removed if the TPM changes proceed	\$117,000/MW per year (or about \$1,170/MWh during the 200 periods DG or DR would need to operate to hit the RCPD peaks) <sup>28</sup>	Provides a ‘blanket’ incentive for GXP demand reduction / DG operation, at times of RCPD, irrespective of local or system wide conditions
Area of benefit charge	Added if TPM the changes proceed	Varies dependent upon situation – expected to be materially lower than RCPD signals in 2019 due to no major pending transmission investments (but in theory this incentive could be of a similar order to the RCPD charge (see Appendix C) in some circumstances i.e. where near term investments are expected)	Provides signals for GXP demand management when and where required for the purposes of signalling transmission capacity requirements
Optional LRMC charge	Possibly to be added if the TPM changes proceed	(yet to be determined, and may vary depending on the cost of each particular investment)	
Transmission alternatives	Provided for under Commerce Commission Part 4 price-quality control framework	Would vary dependent upon circumstances	Allows Transpower to procure DG or DR service, where it would be more efficient than conventional transmission solutions.

<sup>27</sup> See Appendix C for more information about the estimation of the strength of incentives.

<sup>28</sup> This is estimated value for 2018, if TPM/DGPP changes did not apply. This is contingent on all parties, or at least the largest parties, at a GXP all responding to try and defer the investment (e.g. as seen in the Upper South Island load control group).

Peak demand signal	Timing	Strength of the signal or incentive <sup>27</sup>	Comment on incentives that arise
Nodal pricing energy spot market	Existing arrangements remain in place	On average over the top 200 RCPD peaks the average nodal price has been ~\$100/MWh <sup>29</sup>	Provides <sup>30</sup> marginal value of energy and reserve signals at each GXP, taking account of transmission constraints, varying over time.  Note: in any given trading period, capacity being used to provide reserves cannot also provide energy (or indeed benefit from any of the above transmission incentive mechanisms).
Reserves Prices (i.e. affecting the use of DR for reserves)		On average over the top 200 peaks, the NI SIR price is of the order of \$75-100/MWh	

### 3.2 Effect of TPM changes on price signals for operation of DG and DR

This sub-section describes the nature of the price-signal for DG and DR at times of peak demand from the current and potential new TPM arrangements. Sections 3.3 and 3.5 discuss how these price signals (and the price signals from the operation of the wholesale market discussed in section 3.4) flow through to incentives on parties to operate DG and DR at times of peak demand or system stress more generally.

At present a substantial portion of transmission charges are recovered based on grid customers' load during regional coincident peak demand periods (RCPD). This arrangement creates a strong price signal to manage grid exit point (GXP) demand in RCPD periods, via demand response or operation of distributed generation. This signal is expected to equate to around \$1,170/MWh in 2019, if no change occurred to the TPM.<sup>32</sup>

As discussed in Appendix B, there is a material but not perfect correlation between periods of regional peak demand, and national peak demand. Accordingly, the RCPD price signal also indirectly encourages the activation of DG and DR resources during some peak national demand periods but not others.

Under the TPM changes,<sup>33</sup> the RCPD-related price signal would cease to apply. Among other changes, a new area-of-benefit (AoB) charge is proposed, which is intended to target the cost of

<sup>29</sup> This is the average price across the top 200 highest *demand* periods. The average of the top 200 highest *price* periods is about \$220/MWh. This is because it's often reductions in supply causing high prices, not necessarily peak demand (e.g. Otahuhu B, TCC and Huntly Unit 4 were all unavailable during a high priced period in January 2015). However, the removal of RCPD transmission signal may see the nodal price for (at least some of) these periods increase, if a rise is needed to incentivise additional supply or DR.

<sup>30</sup> The historical nodal prices include the effect of DG operating decisions and DR reacting to the RCPD signal, so prices would be expected to be higher in the event of RCPD being removed, all other things being equal.

<sup>32</sup> This is based on the forecast interconnection rate of \$117/kW, and assumes parties operate for 200 trading periods (100 hours), to have a high level of confidence of reducing net demand during the 100 trading periods with regional highest demand. The Electricity Authority has previously used 150 periods for similar purposes. Either value is appropriate, depending on the assumptions used. Using a lower number of periods in this analysis would increase the price signal, but would not change the conclusions.

<sup>33</sup> This discussion focuses on the TPM proposals as they affect DG and DR. The DGPP proposals only apply to DG and are discussed in the subsequent sub-section.

future grid investments<sup>34</sup> more closely to those participants who benefit from them. We understand that the Authority expects the prospect of increased AoB charges (and the prospect of transmission alternative payments) in the future (if a grid upgrade were to occur) will provide incentives for transmission customers to manage their peak demand on the grid when and where it matters.<sup>35</sup> The TPM proposals from May 2016 also provide for Transpower to consider the introduction of a charge based on long run marginal cost (LRMC), to defer grid investment where it is efficient to do so.<sup>36</sup>

These signals would vary in magnitude depending upon specific circumstances. As discussed in Appendix B, we estimate that the forward looking price signal from the AoB could be similar in magnitude to the RCPD signal in areas where there is an impending transmission investment that can be deferred. Conversely, it will be much lower in other areas where no investment requirement is likely in the near term. We have not sought to estimate incentive effects at specific GXPs, as that is outside the scope of this report. However, as a broad generalisation, for 2019, we expect the incentive effects from prospective AoB charges to be materially lower than the direct incentive from the RCPD charge that would otherwise apply.

Notwithstanding the presence of the AoB and LRMC elements, a significant number of participants appear to have interpreted the TPM proposals released in May 2016 as permanently removing any price signal to manage peak grid demand.<sup>37</sup> It is not clear why this interpretation has emerged. Possible explanations include:

- Misunderstanding of the TPM proposals – while incentives to manage peak grid demand are addressed explicitly in the Authority’s documents, transmission pricing is complex and there is a considerable volume of material to absorb.
- Transition issues – to assess the prospective AoB signal, participants would need to understand the likelihood and timing of grid investment, the resulting AoB charge impact for them, and options to defer investment. The processes and information to support this are likely to require development, relative to current arrangements.
- Targeting – the proposed AoB charge is intended to provide signals when, and where, it matters the most. However, where a prospective investment provides benefits to multiple parties, it may be difficult for them to assess the effect of their individual actions. This will be less of an issue where benefits are concentrated among few parties, or if coordination among parties is not unduly difficult.
- Incentives on EDBs – transmission charges are treated as a pass-through for those EDBs subject to price-quality control. Some EDBs have said they are reluctant to reflect the prospect of higher AoB transmission charges into distribution charges for the current regulatory control period (covering 2015 to 2020). This is because material divergences between costs and prices in the current period will increase the likelihood of inadvertent breaches of their price control, and the scope for customers to criticise EDB pricing – especially from larger users.
- Status of LRMC charge - while the LRMC charge could provide an explicit charge in the current period (rather than a prospective charge), the May 2016 TPM proposals allow for Transpower to consider it, rather than requiring its adoption.

### 3.3 Effect of DGPP changes on incentives to operate DG

We understand that EDBs typically interpret the existing distributed generation pricing principles as requiring them to pay DG owners an amount equivalent to the avoided transmission charges that

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<sup>34</sup> As well as major existing grid upgrades.

<sup>35</sup> See Authority TPM proposals, paragraphs 7.28-7.179.

<sup>36</sup> See Authority TPM proposals, paragraphs 7.285-7.306.

<sup>37</sup> For example, see submissions on Authority TPM/DGPP proposals.



result from DG operation, unless the parties agree otherwise. Similarly, EDBs interpret the DGPPs as requiring to pay amounts equivalent to avoided costs of distribution, and being unable to charge more than incremental connection costs to DG owners.

We assume that the DGPPs will be changed as set out in paragraph 1.1.

### 3.4 Wholesale market incentives

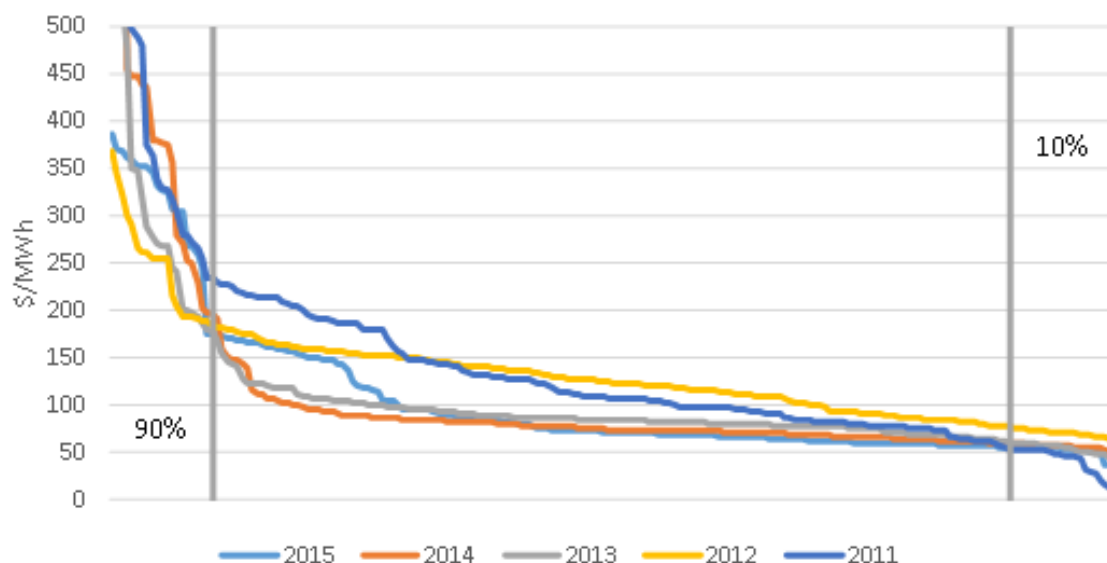
In addition to transmission-related incentives, many DG and DR resource providers are exposed (directly or indirectly) to price signals from the wholesale market. The mechanisms include:

- Direct exposure to nodal energy prices – which encourage additional supply/reduced energy demand during periods of higher prices
- Direct exposure to Instantaneous reserve (IR) prices – this is especially relevant to ripple control of hot water heaters, a sizeable proportion of which is offered as interruptible load into the IR market.
- Contracts – where resource providers are contracted to another party (such as a retailer) to operate in certain fashion, such as maximising generation when requested to do so. In these cases, the resource provider may not be directly exposed to nodal energy or IR prices, but the contractual counterparty will generally be exposed to these prices. Furthermore, the counterparty will have incentives to reflect nodal energy and/or IR signals into the contract arrangements, if the resource provider’s actions materially affect its spot market exposure.

As noted in Table 3, nodal energy and IR prices are typically elevated when the system is tight – which can be due to high demand, or supply contingencies. Furthermore, there is a substantial (but not 100%) correlation between system and regional peak demand peaks. (Although it should be noted that, in any given trading period, capacity being used to provide reserves cannot also participate in the energy market (or indeed benefit from any of the above transmission incentive mechanisms).

Figure 7 shows nodal prices at Haywards during the 200 trading periods with highest national demand, since 2011. It shows that prices have generally been in the range \$50-250/MWh during these periods.

**Figure 7 - Observed nodal prices during highest national demand periods**



The TPM/DGPP changes would not directly affect the wholesale market. However, to the extent that the changes lower the contribution of DG or DR during RCPD periods (all other factors being equal), this would be expected to place upward pressure on energy and reserve prices in such periods<sup>38</sup>. In effect, this would create some countervailing effect on incentives for such providers, although it is not possible to assess the relative magnitudes with certainty.

### 3.5 Hot water ripple control incentives

As noted earlier, ripple control of hot water heaters is thought to provide approximately 700 MW of effective DR resource. This resource can be utilised in number of different ways including:

- Switching load off to reduce transmission charges (the widespread current practice)
- Switching load off to reduce energy charges
- Switching load off to reduce distribution investment requirements and hence costs
- Switching load on, so that water heating demand can be offered into the reserves market as interruptible load (IL).

Clearly, the last option cannot be pursued at the same time as any of the other options, since it requires hot water cylinders to be consuming power and available for ‘interruption’.

#### 3.5.1 Reduced use of ripple control DR to enable higher provision of IL

Some EDBs regularly offer hot water load into the reserves market as IL, but periodically reduce their IL offers, and use ripple control to reduce energy demand. This behaviour is believed to be driven by the incentive to avoid transmission charges<sup>39</sup> (i.e. the trading period was very likely to be a RCPD period, and the RCPD price signal is generally much higher than the IL price signal).

We expect this behaviour to be much less common if the TPM changes apply, because the transmission charge signal will be lower on average, and the IL price signal is therefore more likely to dominate.<sup>40</sup> As a consequence, we expect hot water load in ‘RCPD’ periods to increase relative to the status quo (since water heaters must be switched on to be capable of providing IL).<sup>41</sup>

From market data, we estimate that there is around 170 MW of IL that could be affected. In addition, EDBs are exposed to compliance penalties if they under-deliver their cleared volume of IL. For this reason, the increase in energy demand is expected to exceed the face value of the IL quantity being cleared. It is difficult to know with certainty the multiplier that should be applied, but market data suggests that around +20% is reasonable. This would imply an increase in energy demand<sup>42</sup> from hot water cylinders in ‘RCPD’ periods of around 205 MW, relative to the status quo.

While the above effect would increase energy demand, it will also increase the availability of IL, all other factors being equal. This in turn is expected to free up some generation resource that would otherwise be required to provide spinning reserve. While the interactions are complex and specific to each situation, examination of past market data suggests that an approximate 1:1 substitution ratio between IL and spinning reserve is likely in peak demand periods. The overall net impact of these influences is likely to be a reduction in capacity contribution of around 50 MW (i.e. 205 MW of

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<sup>38</sup> See Section 5.

<sup>39</sup> See para 4.13, “2014 Winter Grid Emergencies” paper <https://www.ea.govt.nz/dmsdocument/18801>

<sup>40</sup> As set out in Table 3.

<sup>41</sup> It is also possible that ripple control will be used to turn off hot water heating during RCPD periods in response to nodal energy prices – however, it is not clear whether EDBs (who typically control the relays in the first instance) are likely to respond to energy prices at present, whereas they are observed to respond to IR prices. The following discussion assumes that in the absence of RCPD signals, EDBs mainly respond to IR price signals.

<sup>42</sup> This increase in demand is assumed to increase losses by 15 MW.

additional hot water load, plus 15 MW of additional losses, minus 170 MW of additional generation, freed up from spinning reserve). Incentives on EDBs

We have also considered whether broader changes in use of ripple control DR are likely to occur. We note that control of this resource varies across the country, but typically host EDBs exercise primary operational control, subject to decision rights of other parties. These include end-users, retailers, owners of ripple control receivers, and/or load aggregators.

The presence of multiple parties with differing rights creates some uncertainty over how this resource would respond to a change in nodal price incentives. In particular, if nodal energy price signals were higher during RCPD periods following adoption of the TPM/DGPP changes, it is unclear how effectively DR from ripple control would be able to respond, at least initially. For example, one EDB has indicated that it may need to consult with retailers operating on its network before making changes. It also noted that based on experience, retailers have mixed incentives to support such a change, because some have upstream generation interests.

The organisational incentives on EDBs are also relevant. In theory, these differ depending on whether EDBs are subject to the price-quality regulation under Part 4 of the Commerce Act. EDBs not subject to price-quality control must meet the 'consumer-controlled' exemption criteria under the Act. For these networks, it might be expected that ripple control will be heavily utilised to reduce transmission (and potentially energy) charges, given that these are ultimately recovered from consumers.

While we understand that this philosophy does apply in some EDBs, anecdotal evidence also suggests that load control initiatives are not strongly pursued in some EDBs exempt from price-control. It is not clear whether this is due to differing local circumstances (e.g. absence of benefits from load control<sup>43</sup>), or different corporate philosophies. In any case, it means there is uncertainty about the extent to which ripple control is utilised in RCPD periods at present, as well as under future alternative arrangements.

For EDBs subject to price-quality control, transmission charges are treated as a pass through cost, so there is no direct incentive to seek to reduce the contribution to RCPD via ripple control as there is no financial benefit to the EDB (though there is likely to be to their end customers). At present, we understand that some regulated EDBs do undertake significant peak demand management during RCPD periods – which may be due to their desire to minimise their customers' charges – whereas other regulated EDBs don't undertake peak demand management to the same extent. Again, it is not clear what is driving such differences in approach.

Even if EDBs perceived no transmission charge benefit from ripple control, it is not clear that this would lead to a sudden cessation in its operational use. Ripple control may still provide distribution level benefits in some cases – noting that with limited ripple signalling channels, EDBs may be unable to precisely target control to customers on parts of a network affected by distribution capacity constraints. Moreover, EDBs are unlikely to make significant operational cost savings by reducing ripple control use, because most costs are sunk. The more important decision point for EDBs is likely to be when reinvestment is required in signalling equipment, and these decisions are likely to arise progressively at different locations over time.

Similarly, for end-users that are currently subject to ripple control of their hot water cylinders, it is not clear that ceasing control would yield material amenity benefits. This is because such customers have generally sized their hot water cylinders and heating elements to reflect an expectation of ripple control. For this reason, even if the tariff benefit was reduced relative to previous levels, they

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<sup>43</sup> While this may be true for distribution capacity requirements, under the current RCPD regime, not controlling load for an EDB network would inevitably result in consumers on that network incurring higher transmission charges.

may prefer to continue with control. Of course, for customers considering an investment in a new hot water heating system, the price signals would be more relevant, and may make it unattractive to invest in new hot water systems with ripple control.<sup>44</sup>

More generally, EDBs are likely to consider several factors when setting distribution tariff structures. Clearly, a change in transmission prices would be one important factor. However, most EDBs are likely to seek to phase in any significant change for mass-market customers over several years, to avoid so-called 'rate shock'. This suggests that overnight removal of controlled/uncontrolled load tariff differentials would be unlikely, even if changes to transmission charges removed any peak management incentive (which is not expected to be the case, as discussed in section 3.2).

In light of these factors, aside from the IL-related effect discussed in section 3.5.1, we do not expect any major and swift changes to use of ripple control. A phased approach would also provide more time for EDBs to work with other parties to develop new services based on ripple control, where it is efficient to do so.

### 3.6 Overall effect on incentives

In summary, the TPM/DGPP changes would alter, rather than remove, the transmission-related price signals to manage net demand during grid peak periods. The change in the strength of these signals will be location specific, and depend on a range of factors, some of which cannot be quantified at this point (such as the level of any LRMC-based charges).

There may also be some transition issues as Transpower and participants become familiar with new arrangements, and evolve their processes and information. In addition, to the extent that there is a net reduction in transmission-related incentives to activate DG and DR in peak periods, some countervailing effect could arise from wholesale market prices in these periods.

More specifically, any tightening of the wholesale supply / demand balance due to reduced use of DG and DR should increase the wholesale market signals to provide DG and DR resources where it is efficient to do so – although the ability of hot water ripple control to respond to such signals is less clear cut, at least in the near term.

Overall, these factors mean there is some uncertainty about the degree of change in the incentives operating on DG and DR providers – and for this reason we have adopted a scenario-based approach.

### 3.7 Scenario descriptions

Table 4 describes the scenarios that have been developed to represent the range of possible outcomes for DG and DR behaviour, and sets out the reasoning for DG and DR behaviour in each scenario.

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<sup>44</sup> This may include the incremental cost of a larger hot water cylinder, larger heating elements and a ripple control receiver and relay.

**Table 4 - Scenario descriptions**

Case	DG behaviour and rationale	DR behaviour and rationale
<b>Status quo</b>	Flexible DG plants target regional peak demand periods – and periods where the forecast nodal price exceeds SRMC	Flexible DR resources target regional peak demand periods – and periods where the forecast nodal price exceeds the cost of response
<b>Base case</b>	<p>Nodal prices in RCPD periods are assumed to (at least) reach levels seen in the past (around \$100/MWh on average). Most DG has a short run marginal cost (SRMC) significantly below this level, and it is therefore profitable to operate based on nodal prices.</p> <p>The exception is diesel-fired DG plant - which typically has a higher SRMC.<sup>45</sup> The base case assumes diesel-fired DG plant does not make any capacity contribution in RCPD periods. This may be conservative as in principle this plant will operate if the nodal prices are high enough. However the price threshold is likely to be higher than the ‘headline’ SRMC suggests. Some of the diesel DG is made up of small stand-by diesel generators. This small plant probably faces higher costs in interacting with the market and is therefore less likely to contract to provide ‘demand response’ services if there is a higher degree of revenue uncertainty. There is over 100 MW of diesel-fired capacity in total.<sup>46</sup></p> <p>Other DG plant is assumed to operate as per the status quo, either because it is inflexible, or because owners will continue to</p>	<p>Grid-connected industrial users that have been observed to respond to RCPD signals (rather than nodal prices) are assumed to cease such DR, on the basis that peak signals from AoB/LRMC charges are lower and/or less predictable, and the subsequent nodal price increase from tighter supply / demand balance is insufficient to compensate. There is around 50 MW of capacity estimated to be in this category, as discussed in section 2.5.2.</p> <p>Likewise, some commercial and industrial DR based solely on the RCPD signal is assumed to cease. In the absence of specific data for this category, it is assumed to be the same as for grid-connected industrial load (i.e. 50 MW). For the reasons discussed in section 2.5.2, this may be an over-estimate.</p> <p>Ripple control of hot water is assumed to be largely unchanged – except for the net reduction in capacity contribution of 50 MW from increased use for IL, as discussed in section 3.5.1.</p>

<sup>45</sup> For diesel-fired plant, this is estimated to be at least \$270/MWh based on a fuel cost of \$25/GJ and \$25/MWh variable operating and maintenance cost. If there are significant communication or other costs (i.e. likely for small scale of plant which makes up the majority of the diesel capacity), these costs will increase. One EDB has reported that small scale diesel requires around \$600/MWh to be attractive to operate. However, some diesel-fired plant may also need to operate periodically for warranty or other purposes, in which case the avoidable cost of operation will be lower in some periods.

<sup>46</sup> The estimate based on market data is 117 MW as per Table 2. Strictly speaking, this should be de-rated slightly because it is not 100% reliable – however the derating would be minor and there is a degree of uncertainty about the actual capacity that is installed.

Case	DG behaviour and rationale	DR behaviour and rationale
	make plant available because nodal prices (on average) are likely to exceed the plant SRMC.	
<b>Sensitivity case 1</b>	As per Base case	<p>As per the base case – but a larger reduction in ripple control use is assumed. For the purposes of sensitivity testing, the case assumes a 50% reduction in ripple control contribution (i.e. the mid-point between the status quo and a zero contribution).</p> <p>This could arise from under-estimation of the IL-related effects discussed in section 3.5.1, and/or broader changes to operational practices by EDBs.</p>
<b>Sensitivity case 2</b>	<p>As per the base case – but sizeable proportion of the DG plant that has operational flexibility chooses to not reliably contribute during tight system periods. Although they forgo some short term earnings (because nodal prices exceed SRMC), they expect the strategy to yield value via:</p> <ul style="list-style-type: none"> <li>• Higher avoided cost of distribution payments</li> <li>• Higher payments from Transpower for transmission alternatives, and/or</li> <li>• Other revenues sources.</li> </ul> <p>For the purposes of sensitivity testing, the case assumes 50% reduction in capacity contribution from wind and hydro plant (i.e. the mid-point between the status quo and a zero contribution).</p> <p>This is equivalent to around 400 MW of capacity.<sup>47</sup></p> <p>Other DG plant is unlikely to be able to restrict generation at short notice, and is assumed to operate as per the status quo.</p>	As per base case.

<sup>47</sup> Deratings from the ASoSA analysis have also been applied to the name plate capacities.

Table 5 shows the total assumed net reduction in DG and DR in peak demand periods, under the three scenarios.

**Table 5 – Assessment of the reduced DG and DR capacity at peak demand**

Potential Reduced Peak Contribution (MW) <sup>48</sup>			
	DG	DR	Total
Base case	120	150	270
Sensitivity 1	120	470	590
Sensitivity 2	400	150	550

### 3.8 Relative likelihood of scenarios

The scenarios have been developed from information on the volume of DG and DR resources currently available during system peak periods, and our understanding of the incentives that operate on the decision-makers who control these resources.

We regard the base case as being the most representative of likely outcomes. This assessment is based on the following factors:

- Financial incentives have been robust predictors of DG behaviour to date. Under a change from RCPD to nodal price incentives, we expect most DG to continue to be rewarded from operation during system peak periods (except for diesel-fired generators due to their higher SRMC). The behavioural assumption is also supported by the observed behaviour of some notionally embedded plant. Prior to that plant becoming notionally embedded (i.e. when not targeting RCPD), significant peak contributions were made.<sup>49</sup>
- Financial incentives are also expected to be robust predictors of behaviour by grid-connected users, and other commercial and industrial customers with DR capability.
- Ripple control DR is the issue of greatest uncertainty. Multiple parties have decision-rights, and drivers are less clear cut. Nonetheless, aside from the IL substitution effect, an abrupt and widespread change to operating practices seems relatively unlikely, for the reasons set out in section 3.5.

We regard Sensitivity case 1 as being relatively unlikely, but we cannot rule it out based on current information. For ripple control, it assumes there will be a swift and relatively widespread change in EDB behaviour, despite the factors set out in section 3.5. Furthermore, it assumes that EDBs would generally not activate any available ripple control in the lead up to a system peak period, unless the system operator sought curtailment (i.e. using Schedule 8.3 of Technical Code B of the Code). Our understanding is that in the past, there have been occasions when EDBs have increased ripple control in response to a request from the system operator to increase security margins. We are not clear whether such requests are formal or of a voluntary nature.

We also consider sensitivity case 2 to be relatively unlikely, but we cannot rule it out because of uncertainties around some key issues. Our assessment of relative likelihood is based on:

<sup>48</sup> Estimates are rounded to two significant figures in table.

<sup>49</sup> See page 16 of the report; [https://www.transpower.co.nz/sites/default/files/uncontrolled\\_docs/Matahina-Aniwhenua-PDA-external-report.pdf](https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Matahina-Aniwhenua-PDA-external-report.pdf) and [https://www.transpower.co.nz/sites/default/files/uncontrolled\\_docs/Waipori-PDA-External-Report.pdf](https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Waipori-PDA-External-Report.pdf)



- To have a security impact, a significant proportion of DG capacity would need to be unavailable at times of system stress. As noted in section 2.3, these do not always coincide with peak demand periods, and can be difficult to predict in advance. Owners of this plant would be consciously forgoing a short-term net revenue opportunity in exchange for uncertain revenue gains from alternative sources at a later date. Such DG owners may also become net spot purchasers in these periods, if they have contract positions or retail load commitments based on their full DG capacity. This would increase the financial risks to DG owners from adopting this approach. DG owners would also need to consider the Commerce Act, especially the prohibition on contracts, arrangements, or understandings that would substantially lessen competition.
- For DG plant subject to offer requirements, owners might prefer to lift their offer prices rather than physically withdrawing plant, as that would carry less nodal price risk. However, in that instance, DG plant would be physically available and therefore not affect security margins. Furthermore, DG owners would need to be mindful of the trading conduct provisions in clauses 13.5A and 13.5B of the Code, and the potential for higher nodal prices to attract competitor response and/or new entry.

We note also that other possible outcomes could arise. These could result in a more modest degree of change to capacity margins than the base case (especially if nodal prices rise sufficiently to elicit operation of diesel DG).

Alternatively, the degree of change could be more marked, such as some combination of sensitivity cases 1 and 2. Having said that, we believe there are counteracting influences that make a combination of cases 1 and 2 very unlikely. Put simply, if demand response was much reduced (as in case 1), the opportunity costs and risks for DG owners of not operating in peak periods would be even higher, making it less likely that widespread withdrawal of DG would occur. Similarly, if there was widespread withdrawal of DG in peak demand periods (case 2), it appears less likely that EDBs would fail to respond if requested by the system operator to initiate ripple control of water heating load.



## 4 Capacity margins for 2019

This section sets out the effect of the DG and DR scenarios on projected winter capacity margins for 2019.

### 4.1 Winter Capacity Margin 2019 - Base case

The left hand column of Figure 8 shows Transpower’s projected North Island winter capacity margin for 2019, based on existing, committed and ‘high-probability’<sup>50</sup> new generation plant, and the case where the Huntly Rankine unit retirements do not proceed in 2019.<sup>51</sup>

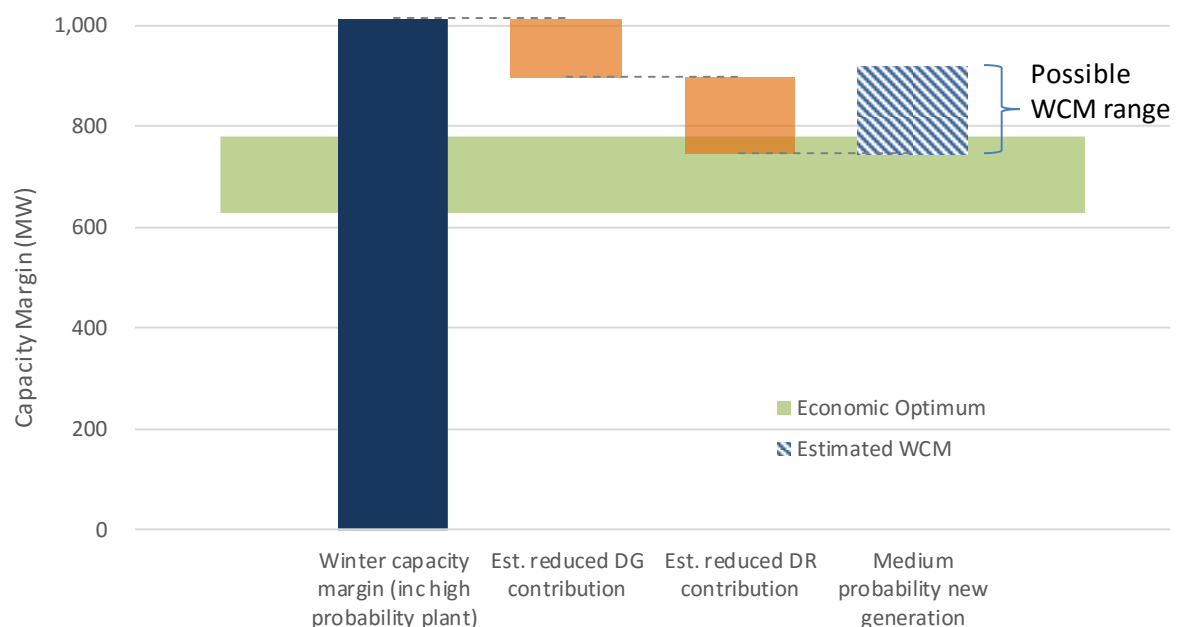
The assessed economic optimum level of the capacity margin is highlighted in green. This is the amount of capacity that is expected to minimise the sum of generation plant costs and shortage costs. If the WCM falls below the optimum level, the expected level of costs from shortages would be higher than the cost of additional generation resource, and vice versa.

The projected WCM in the status quo based on existing and ‘high probability’ plant (blue bar) is 1014 MW, as compared to an economic optimum range of 630-780 MW (green band).

Under the base case, some reduction in DG and DR operation at peak is expected, and this is shown by the middle orange bars respectively. The net impact reduces the projected WCM to around 750 MW, which is within the economic optimum range.

If new investment categorised as ‘medium probability’<sup>52</sup> is also included (blue cross hatch bar), the projected WCM is around 920 MW, which is above the upper end of the economic optimum range. Concept expects that most ‘high probability’, and some ‘medium probability’, generation will be completed. As such, the winter capacity margin is expected to be within the hatched region.

**Figure 8- Base case- Winter Capacity Margin impact**



<sup>50</sup> Transpower’s ASOSA discusses potential new generation plant that is expected to be available on the system by 2019. ‘High probability’ generation includes plant that has a 75% likelihood of proceeding according to responses to an industry survey.

<sup>51</sup> See Appendix E for further discussion on the WCM scenario that has been used.

<sup>52</sup> ‘Medium probability’ generation includes plant that has a 50% likelihood of proceeding.

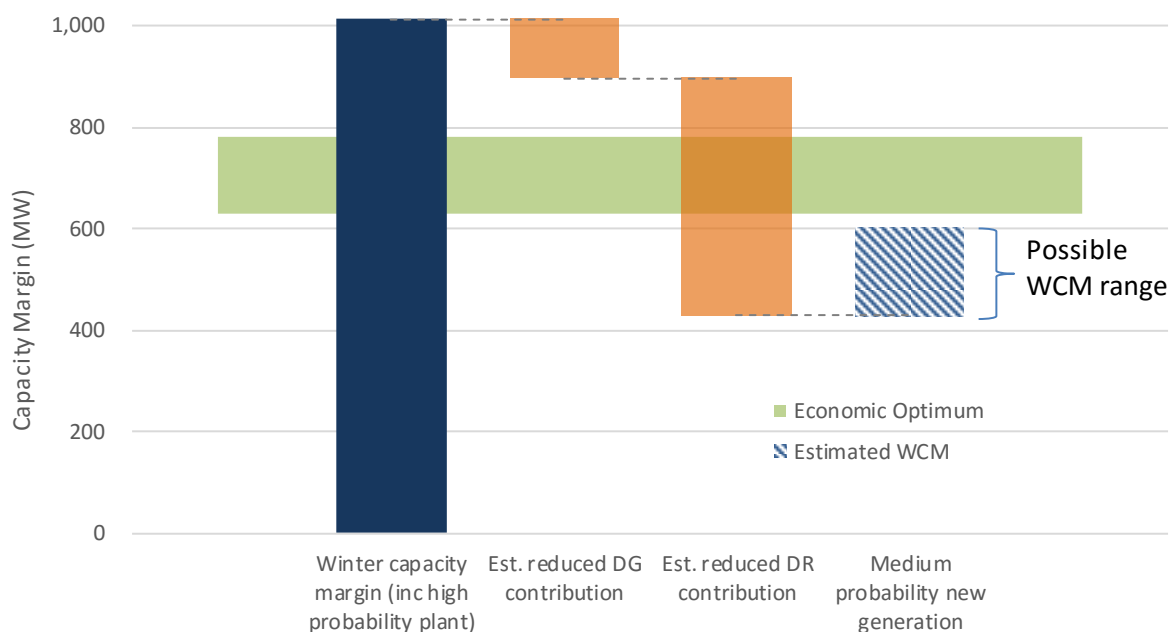
## 4.2 Winter Capacity Margin 2019 - Sensitivity case 1

Although we do not expect a material change in ripple control DR in the near term, we have considered a sensitivity case in which there is a 50% reduction in DR contribution from this source,<sup>53</sup> and all other assumptions are unchanged. While we regard this sensitivity case as being significantly less likely than the base case, we recognise that there are uncertainties about the amount of ripple control DR that is available, and the incentives operating on parties who control its use, and its interaction with the reserves market.

Furthermore, unlike DG owners, EDBs who exercise operational control of ripple relays do not appear to have a clear financial incentive to respond to nodal prices at present.<sup>54</sup> To the extent that ripple control DR can yield value for energy market purposes, a tightening of the incentive linkages between EDBs and other parties such as users/aggregators/retailers would be expected to develop. However, that may not have occurred by 2019, given the complex nature of the issues and number of parties involved.

In aggregate, these effects would reduce the projected winter capacity margin for 2019 by around 585 MW. As shown by Figure 9, the resulting 2019 winter capacity margin based on existing and 'high probability' plant would be around 430 MW, which is well below the assessed economic optimum range. However, if prospective new plant investment categorised as 'medium probability' by Transpower is included, the resulting winter capacity margin is around 600 MW, which is somewhat below the lower end of the economic optimum range.

**Figure 9 - Sensitivity case 1 - Winter Capacity Margin**



## 4.3 Winter Capacity Margin 2019 - Sensitivity case 2

Although we expect the capacity contribution from most DG to be unchanged, we have considered a sensitivity case where a sizeable amount of non-diesel DG restricts its generation levels in tight

<sup>53</sup> This may reflect a reduction in HWC load of greater than assumed in the base case and/or a scenario in which increased HWC load is not offered back into the IL market as expected in the base case.

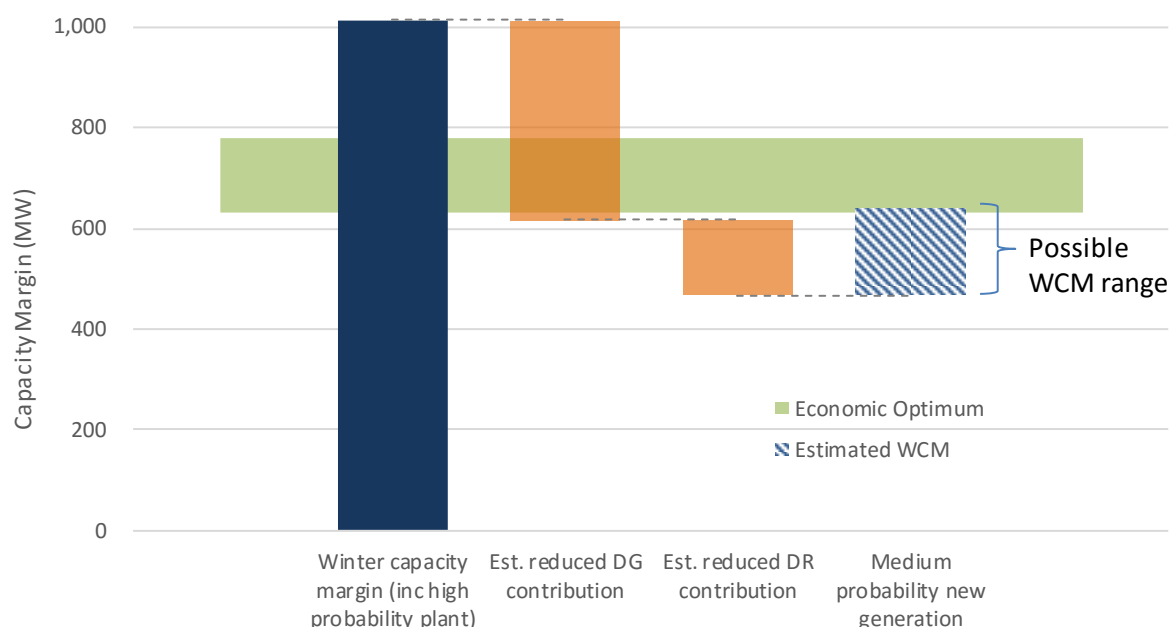
<sup>54</sup> The exception is ripple control which can participate in the reserves market. However, this is a subset of ripple control DR.

system periods (foregoing immediate spot revenues), in the belief this will yield future net benefits, such as higher payments for transmission support from Transpower.

In this case, we assume the firm capacity contribution from hydro and wind DG plant is reduced by 50% relative to the base case. No change is assumed for other DG (such as cogeneration, and landfill gas-fired plant), because these plants are unlikely to have sufficient flexibility to restrict their generation levels at short notice. This equates to a 400 MW reduction in the firm capacity contribution from DG. This roughly twice the observed difference between average DG output in RCPD periods, and the 100 hours of lowest DG contribution across a year.<sup>55</sup>

In aggregate, these changes would reduce the projected winter capacity margin for 2019 by around 550 MW. As shown by Figure 10, the resulting 2019 winter capacity margin based on existing plant would be around 470 MW. This is well below the economic optimum range. If prospective new plant investment categorised as ‘medium probability’ by Transpower is included, the resulting winter capacity margin would be around 640 MW, which is close to the lower end of the economic optimum range.

**Figure 10 - Sensitivity case 2 winter capacity margin impact**



#### 4.4 TPM operational review amendments

The preceding sections show the effect of the scenarios, relative to the projected WCM in Transpower’s ASoSA issued in early 2016. Before commenting further on these results, we note that the ‘starting’ WCM may not be strictly accurate.

In 2015, the Authority approved changes to the existing transmission charge regime as part of the TPM operational review. The main amendment of relevance in this context is the allocation of charges for the High Voltage Direct Current (HVDC) link, which is changing from a peak capacity measure for South Island generators (i.e. Historical Anytime Maximum Injection, or HAMI) to an average injection or energy measure (i.e. South Island Mean Injection, or SIMI). This change reduces the incentive on South Island generators to limit their maximum output, and took effect from

<sup>55</sup> This is based on DG for which half-hourly output data was available, and excludes some smaller scale plant. See Figure 6 for more information.

September 2015. For example, relative to the assumed peak contribution in the 2016 ASoSA of 666 MW, the Clutha hydro scheme has regularly generated at up to about 780 MW since September 2015, an extra 114 MW<sup>56</sup>.

To improve the North Island WCM, greater flexibility from South Island generation would need to be matched by availability of HVDC capacity. Our initial analysis indicates that while the HVDC does sometimes have spare capacity at times of peak demand, there are also times when transfer capacity is very limited. Therefore, not all of the South Island's increased capacity is expected to be transferable to the North Island during peak periods. A further complication is the extent to which the HVDC is reserve constrained rather than capacity constrained. As discussed in section 3.5.1, there may be increased availability of reserves which may mitigate some of the HVDC constraints.

Given the complexity, we do not have sufficient information to quantify the potential impact of increased South Island generation flexibility. However, we note that it would tend to lift the winter capacity margins in the base and sensitivity cases (but not to the full extent of increased South Island flexibility), all other factors being equal.

#### 4.5 Overall observations regarding winter capacity margin

As set out in the base case discussed in section 4.1, we expect the most likely outcome of the TPM/DGPP changes will be to reduce the 2019 WCM by around 270 MW. This results in a WCM of 750MW if all 'high probability' and no 'medium probability' generation plant is built, which is within the economic optimum range.

However, we note there are some important uncertainties about the incentives applying to certain parties – particularly EDBs in relation to ripple control of hot water and some DG owners. We have therefore considered two alternative 'downside' scenarios. Although we consider these to be less likely, they would result in a larger reduction in the WCM.

Finally, we note the assessment set out above does not take account of the increase in offered South Island peaking generation capacity following the transmission price changes approved in 2015.

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<sup>56</sup> Meridian's behaviour is more difficult to assess due to substantial differences across different years.

## 5 Indicative impacts on market prices

While the majority of this report focuses on the potential for security impacts to arise from the TPM/DGPP changes, another consideration is the potential impact on nodal prices.

Nodal price impacts are subject to even more uncertainty than quantity effects, because there is more scope for behavioural influences to affect outcomes. The following sections therefore present broad indications of nodal price effects.

### 5.1 No sustained effect on prices expected

Nodal prices at any particular point in time will be influenced by a range of factors including demand levels, generator availability and costs, and participant contract positions. Over time, average nodal prices need to be sufficient to attract and sustain supply, in order to meet demand. Similarly, average nodal prices are not expected to persistently exceed the cost of new supply, as that would attract entry which will in turn dampen nodal prices.

Accordingly, a tightening of the system margin<sup>57</sup> would be expected to put upward pressure on nodal prices, which will in turn attract new supply or demand response resources, and therefore self-correct. Likewise, an increase in the system margin would also be expected to self-correct over time.

We expect these fundamental dynamics to continue to apply into the future. For this reason, we do not expect any permanent effect on average nodal prices from the TPM/DGPP changes per se, relative to a situation where they do not apply.<sup>58</sup> However, to the extent changes result in a temporary disequilibrium, then some price change would be expected in the transition period. This is expected to be a desirable effect, as the nodal prices would better reflect the true cost of supply and willingness of demand to pay.

### 5.2 Potential transitional scenario

It is not possible to estimate potential transitional price effects with precision, due to the uncertainties about participant behaviour and other factors. Instead, we have adopted a scenario based approach, which uses observed supply offers and demand bids for national peak demand periods in 2015 as a starting point. We then consider the impact in each trading period if the capacity margin had been reduced by an amount broadly equivalent to the base case discussed in section 4.1.

If approximately 270 MW of additional demand (the base case estimate) is simply added to existing demand, this results in infeasible outcomes in many trading periods. This is not realistic because offered generation in each trading period is affected by forecast demand. Furthermore, there is spare thermal generation available in the trading periods when modelled infeasibilities occurred.

For this reason, an additional 200 MW of demand has been added to the 2015 market data during peak periods, and nodal prices have been capped at \$600/MWh. This approach is broadly equivalent to assuming that:

- Demand is higher by 270 MW in national peak periods
- 70 MW of additional resource is available at an SRMC of \$600/MWh – we understand that at this price smaller diesel-fired plant connected to EDBs has been economic to operate. In practice, the

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<sup>57</sup> That is, the difference between projected supply and demand.

<sup>58</sup> In other words, we have no reason to expect that the WCM will differ materially from historic levels. In making this comment, we note that observed WCMs have generally been somewhat above the level assessed as the economic optimum. It is not clear whether this reflects some measurement issue in determining the economic optimum, or other factors.

resource could be DG or DR – but in either case at \$600/MWh some additional resource would be expected to be available. We also note that the RCPD-based price signal has been around this level in the past (see Figure 15) and has been associated with strong capacity contributions from DG and DR.

The result of applying these assumptions and re-solving the 2015 market data is that the average nodal price during the 100 peak hours would increase from around \$100/MWh to approximately \$230/MWh. The time weighted average nodal price over the year would increase by approximately \$1.5/MWh. As mentioned above, the long term drivers of nodal prices will remain unchanged, and so we would not expect any long term change to average nodal prices. This modelled increase in nodal price would be a transitional effect, and subject to the caveats outlined below.

It is important to emphasise that the above is a scenario based on simplifying assumptions. If the assumed price response of the additional resource is higher, the corresponding nodal price effects are smaller, and vice versa.

In addition, the analysis only considers changes during peak periods. Some offsetting impact on prices can be expected at other times. For example, if hot water cylinders have higher demand in peak periods, some reduction in demand is expected in other periods because hot water cylinders largely shift rather than reduce demand.

### 5.3 Effect on price uncertainty

The preceding discussion focussed on potential price impacts. A related issue is the potential impact on forecast price uncertainty.

This is because generation under 30 MW does not need to offer (though generation can be required to offer by the System Operator). It appears that there is about 185 MW of embedded hydro that is larger than 3 MW (thus likely to have some storage) which does not provide offers. This hydro is not seen explicitly in forecast prices because it's aggregated into the demand.

If (say) 50% of this non-offering hydro DG changed its behaviour close to real time, along with 117 MW of the diesel generation, then DG might cause an unexpected demand movement of well over 100 MW that is not signalled through forecast nodal prices. i.e. the demand forecasts which are significantly based on historical behaviour, may start to materially under or over-predict *net* demand.

Similarly, any change in DR behaviour that is not captured through the demand forecast may compound the forecast price uncertainty.

This increased price uncertainty may potentially affect security if it has the effect of forecasting lower prices than are likely to arise (in some cases materially lower), and thus not signalling the need for additional generation or demand reduction ahead of real time.

This may be a temporary effect as DG and DR settle into new operating regimes and forecasting algorithms are updated, but the issue may warrant further consideration to determine the scale and likelihood of impact.

## Appendix A. Assumptions

This section outlines the key assumptions underpinning the analysis in this paper.

### *Transpower Winter Capacity Margin Analysis*

The Transpower Security of Supply Assessment, and specifically the WCM, is used as the baseline for comparison of the peak adequacy in this analysis. Therefore, we need to ensure that the analysis undertaken is consistent (as possible) with the Transpower winter capacity margin analysis<sup>59</sup> (WCM). The WCM is under-pinned by a variety of assumptions. The main assumptions relevant to the WCM analysis are:

- Use of ripple control is reflected in demand in the WCM analysis. Accordingly, any reduction in the use of ripple control arising from the TPM/DGPP changes would be expected to increase peak demand.
- Specific capacity contributions are de-rated below nameplate capacity for some DG. In particular, the firm capacity contribution for wind DG is assumed to be 25% of nameplate capacity,<sup>60</sup> and the firm capacity contribution from hydro DG plant is reduced by 98 MW.<sup>61</sup>

### *Ripple control of hot water cylinders (HWCs)*

A 2006 survey indicated that there was approximately 880 MW of available hot water load in New Zealand subject to ripple control.<sup>62</sup> However, some of this capacity was believed to be inaccessible due to failed ripple receivers. Since this time, investment in smart metering has resulted in some failed receivers being identified and repaired,<sup>63</sup> additionally, some smart metering has the functionality of ripple control. However, the uptake of gas for hot water heating has also meant a possible reduction in ripple control availability in some areas.

There is no definitive information about the current total available ripple control (or similar) load capacity for domestic hot water systems (and the small number of night store heaters). We have therefore estimated the available capacity as 704 MW (i.e. 880 MW less 20%).

Of this available controllable capacity, we have estimated the extent to which ripple control is actively used. The assumptions are set out in Table 4.

### *Hydro plant*

We've assumed that all storage-hydro is operating during RCPD peak. This may be a conservative assumption, but perhaps only slightly so because the RCPD price signal is very strong. Further, documentation<sup>64</sup> around some of the contractual embedding agreements highlights both the capability and value to DG owners of using the hydro storage capacity to significantly reduce RCPD.

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<sup>59</sup> 'Security of Supply Annual Assessment 2016' <https://www.systemoperator.co.nz/sites/default/files/bulk-upload/documents/SoS%20Annual%20Assessment%202016.pdf>

<sup>60</sup> See section 8.5 of *ibid*.

<sup>61</sup> See Table 5 and Table 6 of *ibid*.

<sup>62</sup> This is the 'after-diversity' load, not the sum of the installed water heating element capacities, see "Learnings from Market Investment in Ripple Control and Smart Meters" March 2015

<sup>63</sup> [http://www.powerco.co.nz/uploaded\\_files/Publications-and-Disclosures/Statutory-Documents/Asset-Disclosures/AMP2010.pdf](http://www.powerco.co.nz/uploaded_files/Publications-and-Disclosures/Statutory-Documents/Asset-Disclosures/AMP2010.pdf)

<sup>64</sup> See [https://www.transpower.co.nz/sites/default/files/uncontrolled\\_docs/Matahina-Aniwhenua-PDA-supporting-information.pdf](https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Matahina-Aniwhenua-PDA-supporting-information.pdf) and [https://www.transpower.co.nz/sites/default/files/uncontrolled\\_docs/Matahina-Aniwhenua-PDA-external-report.pdf](https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Matahina-Aniwhenua-PDA-external-report.pdf)

## Appendix B. How constrained is system capacity in RCPD periods?

RCPD periods are not always the national coincident peak demand (NCPD) periods, so any changes in operation of DR and DG during RCPD periods may not have a direct ‘one for one’ impact on national peak demand. That said, our analysis indicates the single highest peak national demand is coincident with the LNI and UNI RCPD periods. The situation is different in the South Island where the degree to which national peak demand and RCPD periods are coincident varies significantly from year to year. This is primarily because the South Island makes up a smaller portion of national demand than the North Island, and because it is more geographically (and thus meteorologically) removed from the main load centre of Auckland. This is shown in Figure 11.

**Figure 11 - Percentage of national peak periods that are RCPD100 periods**

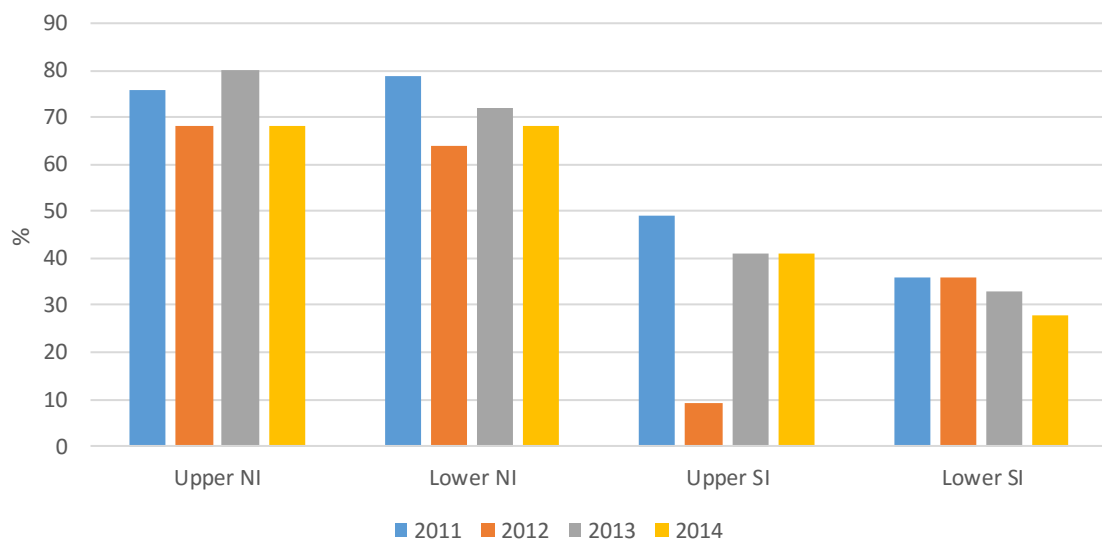
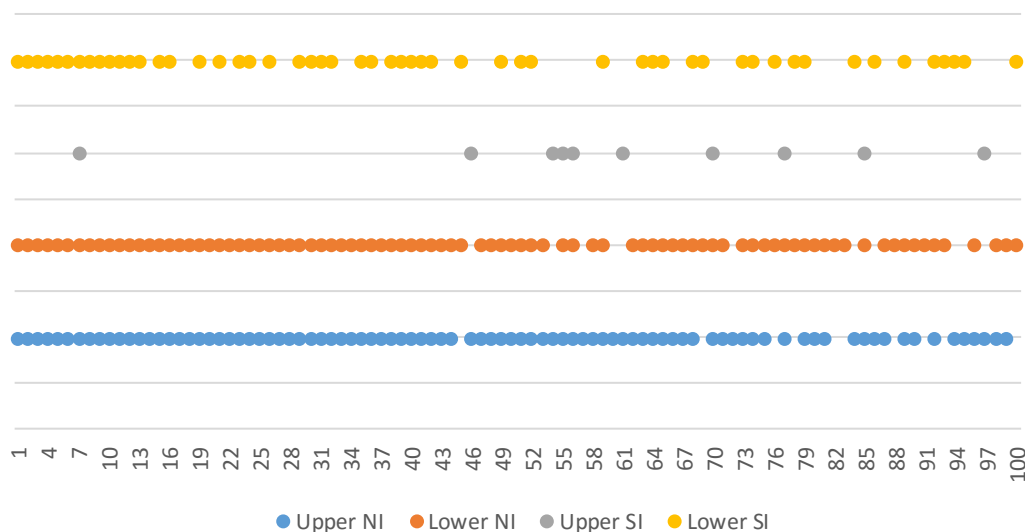


Figure 12 and Figure 13 show national peak periods, with the highest demand period represent by ‘1’ and the 100th by ‘100’. A coloured dot means that that period was an RCPD one for the region.

**Figure 12 - Correlation between national peak periods and RCPD periods - 2012**





**Figure 13 - Correlation between national peak periods and RCPD periods - 2013**

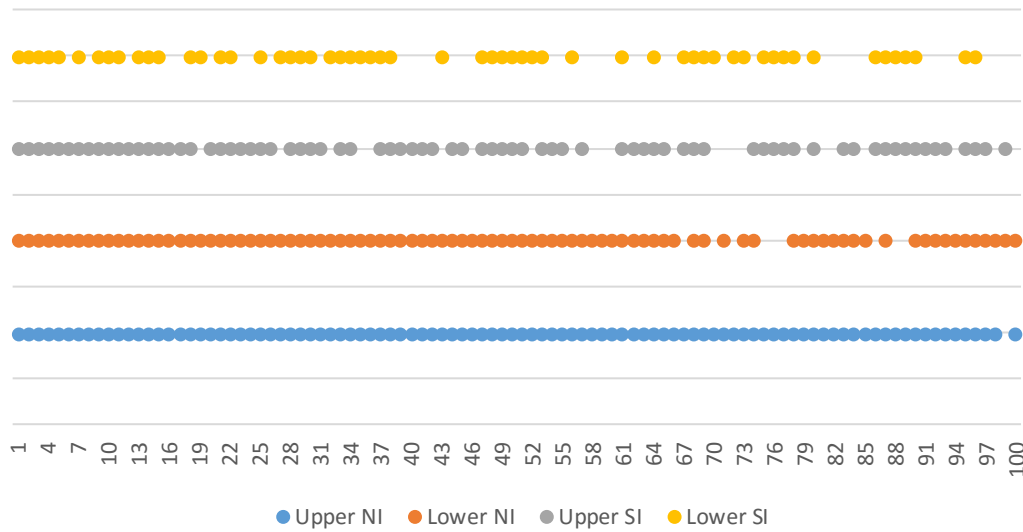
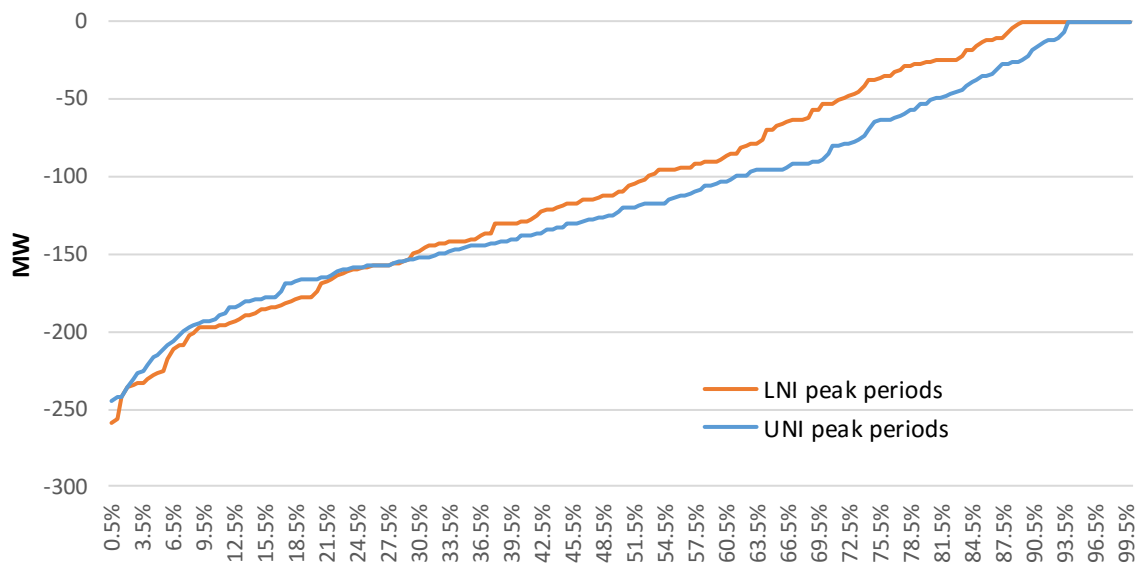


Figure 14 shows that during RCPD periods the HVDC is rarely constrained (by thermal capacity or North Island reserves), the vertical axis being spare capacity, the horizontal axis showing the top 100 RCPD periods). In only about 10% of RCPD periods was the HVDC constrained. This is important because it suggests that the greater South Island generation peaking capability arising from the 2017 TPM amendments (HVDC cost allocator changing from HAMI to SIMI) will be able to be received by the North Island in most instances of RCPD periods. In general, there is no correlation in the data below between the larger peaks being more constrained (i.e. generation patterns are more dominant than demand in terms of influencing whether the HVDC is constrained).

**Figure 14 - Extra reserve-limited transfer capability on HVDC 2015**



## Appendix C. Strength of incentives to manage peak grid demand

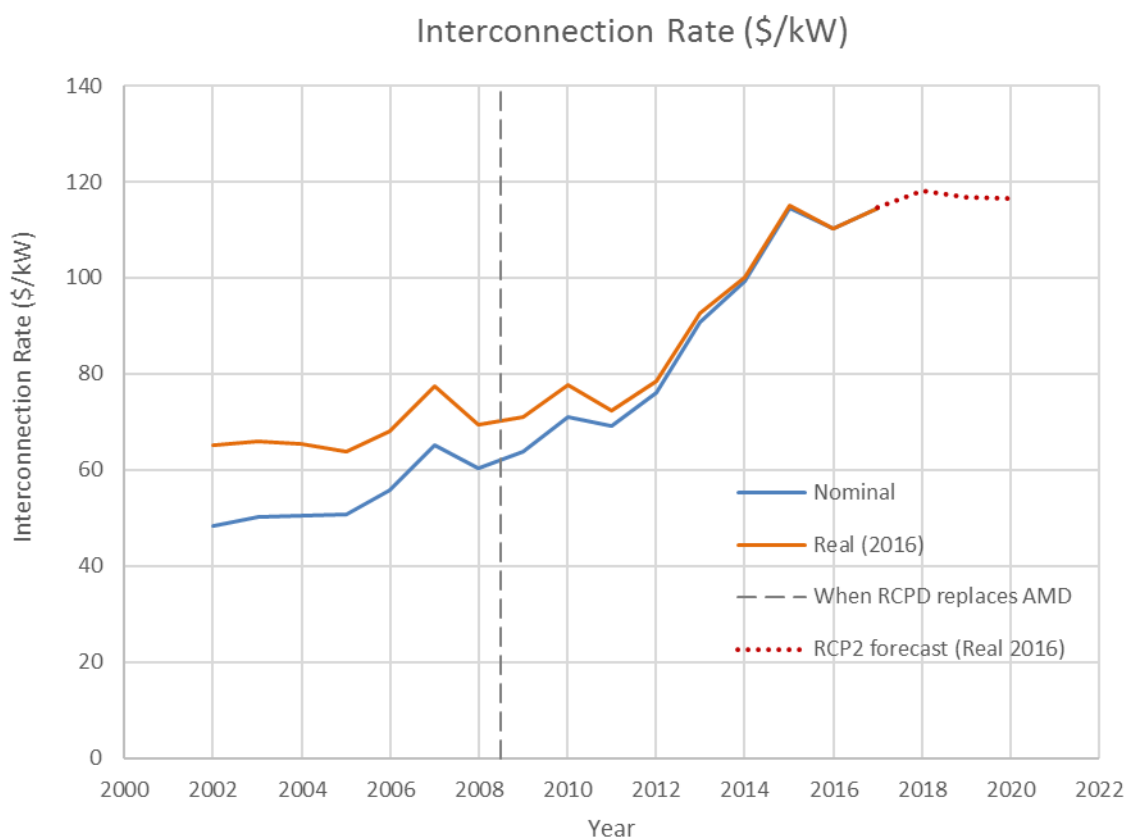
There are a variety of existing and possible price signals that influence the magnitude of GXP consumption at times of peak demand (and hence incentives to activate DG or DR resources). The range of price signals is outlined in Section 3 above. Here we look into a subset of those in detail, namely:

- The RCPD signal (existing, but possibly to be removed)
- Nodal prices (existing and remaining)
- Reserves prices (some DR providers may choose between reacting to energy prices, and using their controllable load as IL) (existing and remaining)
- Area of Benefit Charge (not existing, but potentially to be introduced).

### RCPD signal strength

The RCPD signal is a strong price signal, and is believed to be having a marked effect on regional coincident peak demand, though not necessarily efficiently. Figure 15 below shows how the interconnection charge rate has changed over time, and is forecast to change out to 2019. There has been a rising interconnection rate, as Transpower's revenue allowance has increased following recent investment. While this data is nominal (not adjusted for inflation), the increase is particularly noticeable between about 2010 and 2014.

Figure 15 - Changes in the interconnection rate over time



We expect the current interconnection rate to be strong enough to encourage changes in the operation of some existing plant, and also to influence some investment decisions.

For example, the RCPD signal is likely to be encouraging the use of existing reciprocating diesel generation even when there is sufficient transmission capacity and other lower cost generation. The SRMC of reciprocating diesel generation is of the order of \$270/MWh. Therefore, to run existing diesel generator sets (i.e. assuming they are already installed for stand-by operation) would cost of the order of \$27,500/MW per year to cover 200 trading periods. While the RCPD measure itself is calculated from the top 100 peaks, it is assumed that if a party is trying to reduce their RCPD measure then they'll need to respond to at least 200 peaks because the actual timing of the RCPD periods is only identifiable retrospectively.

Given the estimated 2018 interconnection rate of approximately \$117/kW, the financial incentive to run the diesel generator sets from the RCPD reduction alone is approximately \$90,000/MW (i.e. \$117,000/MW gross benefit less the \$27,500/MW diesel operating cost).

#### ***Nodal Prices during RCPD and National Peak Periods***

To compare the strength of the nodal price signal with the RCPD signal, average prices were calculated for the following periods using 2015 market data:

- the 100 trading periods coincident with RCPD
- the 100 trading periods of peak national demand
- the 100 trading periods of highest prices (regardless of the level of demand)

This data is shown in Table 6 below (note that the annual average nodal price is about \$70/MWh).

***Table 6 - Nodal prices***

\$/MWh	Top 100 national demand peaks	Top 100 RCPD peaks	Top 100 price periods (irrespective of demand)
BEN2201	109	98	217
HAY2201	118	105	253
ISL2201	119	107	261
OTA2201	127	113	273

#### ***SIR Prices (indicative of IL price signal)***

Similar to the nodal prices above for energy, the Sustained Instantaneous Reserves (SIR) prices are shown in Table 7 below. These are an indication of the value of DR for instantaneous reserves.

***Table 7 - Sustained instantaneous reserve prices***

\$/MWh	Top 100 national demand peaks	Top 100 RCPD peaks	Top 100 price periods (irrespective of demand)
UNI	98	75	211
LNI	98	110	211
USI	12	15	58
LSI	12	1	58

### Area of Benefit Charge

The price signal arising from the Area of Benefit charge (AoB) varies spatially and temporally. This is because the price signal depends on when and where new transmission investments are required. This means that the strength of the price signal will be highly variable. However, a broad indication of its potential magnitude can be derived by considering examples of recent investments.

For example, the Otahuhu Gas Insulated Switchgear (GIS) was modelled in the TPM change. This is an investment of about \$90m. It has an annual revenue recovery amount of about \$12m/year.

Looking at the load-duration curves (below), we can determine the number of trading periods that will be required to operate DR on average, to defer the transmission investment a number of years. Using this information, we can estimate the strength of the incentive (in \$/MWh terms) to operate DR to avoid the AoB charge as shown in the following table (i.e. the \$0.5m avoidable AoB charge divided by the number of periods DR must operate). Obviously, to counter demand growth, the DR must operate for a greater number of periods each year, so an average is required over multiple years. However, we can see in the table below that the incentive from the AoB charge is comparable in strength to the RCPD charge.

Initially, when an investment is just required, the AoB charge has a very strong price signal (stronger than RCPD), because the full \$0.5m/year can be avoided with only a few periods of DR. However, over time, the AoB signal reduces in strength (i.e. in \$/MWh terms) as more and more periods of DR operation are required (and a greater DR capacity) to avoid the same \$0.5m/year cost. This can be seen in Table 8 below.

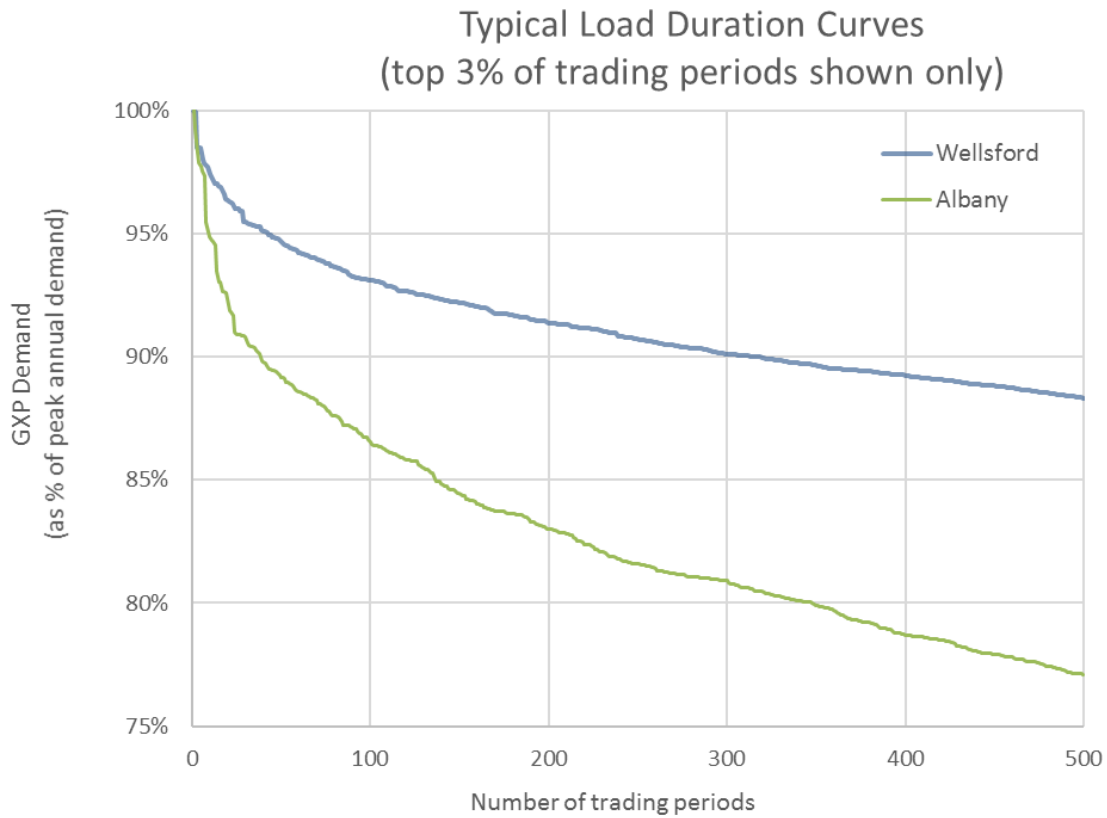
**Table 8 - Indicative strength of the AoB price signal**

Trading periods where DR is required	10	20	50
\$/MWh incentive	20,000	4,000	1,000

It is important to note that:

- The strength of the AoB charge is sensitive to the shape of the load-duration curve (i.e. the steepness of the curve near peak demand), and because of this, variation of the order of +/- 50% or more is likely in the signal strength across various load-duration curves
- The size of the investment is an additional factor affecting the strength of the incentive.

Figure 16 - Load duration curves used to estimate the AoB charge strength



## Appendix D. Industrial demand response

Information about large industrial customers was investigated to assess their response during periods with high nodal prices, and during RCPD periods. In addition, their load bids were compared to their actual responses during periods with high prices. Sometimes their indicated response (signalled via bids) and actual response did not appear to correspond<sup>65</sup>.

Industrial user loads were grouped into three broad categories:

- **Non responsive.** These loads don't appear to respond to the RCPD signal or nodal prices
- **Nodal price responsive.** The bids for these loads indicate that they respond to moderately high nodal prices. They may also respond to RCPD signals.
- **RCPD responsive.** These loads appear to respond to the RCPD signal, but do not have price responsive bids.

The purpose of the categorisation is to identify those tranches of industrial load that are likely to change behaviour as a result of the TPM changes. This equates to identifying tranches that:

1. Currently respond reliably during RCPD, and
2. Would be likely to stop responding, assuming nodal prices are similar to levels observed in the past during RCPD periods (around \$100/MWh on average) – if such users reduce their load at nodal prices below this level, then they are likely to continue to respond in future because nodal prices provide sufficient reward. If they respond at higher prices, their behaviour is more uncertain.

Table 9 summarises the categorisation of the industrial loads. The load tranches that potentially meet the above criteria are shaded.

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<sup>65</sup> This may be because of inaccuracies in real time price signals available to the load.

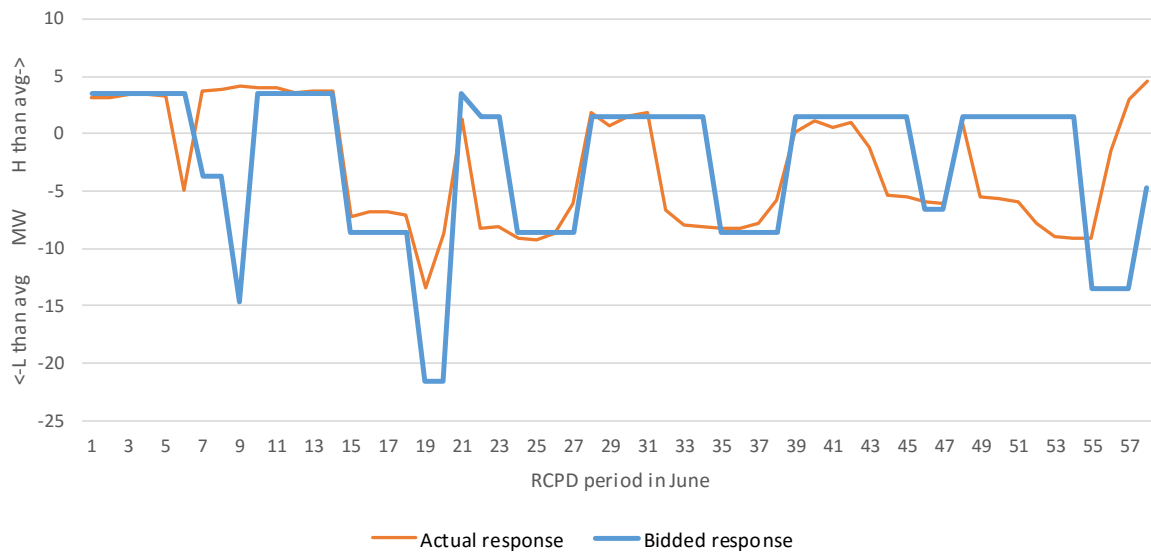
Table 9 - Industrial user demand

	Node	MW	Functional Response Price	Possible impact of RCPD change on behaviour
Non price responsive	KAW0112	11	V. high	Appears unlikely to alter behaviour
Non price responsive	ASB0661	5	V. high	Appears unlikely to alter behaviour
Non price responsive	EDG0331	40	V. high	Appears unlikely to alter behaviour
Non price responsive	KAW0111	11	V. high	Appears unlikely to alter behaviour
Non price responsive	MNG1101	23	V. high	Appears unlikely to alter behaviour
Non price responsive	TWI2201	575	V. high	Appears unlikely to alter behaviour
Nodal price responsive	KAW0113	36	120	Responds at low prices. RCPD change expected have minimal impact on behaviour
Nodal price responsive	KIN0111	42	1000	Doesn't respond to RCPD periods currently – no behavioural change expected
Nodal price responsive	KIN0112	13	1000	Doesn't respond to RCPD periods currently – no behavioural change expected
Nodal price responsive	KIN0113	14	1000	Doesn't respond to RCPD periods currently – no behavioural change expected
Nodal price responsive	WHI0111 tranche 1	40	1000	Appears to respond to RCPD over and above quantities in bids. i.e. bid <i>quantities</i> reduce during RCPD periods. All load is offered at <=\$1000. ~20% of load offered at \$100.
Nodal price responsive	WHI0111 tranche 2	15	100	
		<b>Average RCPD response (MW)</b>	<b>Peak RCPD response (MW)</b>	
RCPD responsive	TNG0111	3	10	Weak evidence of low amounts of RCPD response.
RCPD responsive	GLN0331	30	50	Appears to respond to moderately elevated nodal prices (between around \$200/MWh to \$300/MWh). However, bids do not reflect this.

Figure 17 shows the behaviour of load at TNG0111 during RCPD periods in June 2015. While there is lowering of demand in some RCPD periods, this is far from consistent (until like observed patterns by some other users). It is possible that load reduction is occurring due to some other factor, such as reaching the end of production runs. Overall, the information indicates that the load is not currently a reliable source of DR during RCPD periods.

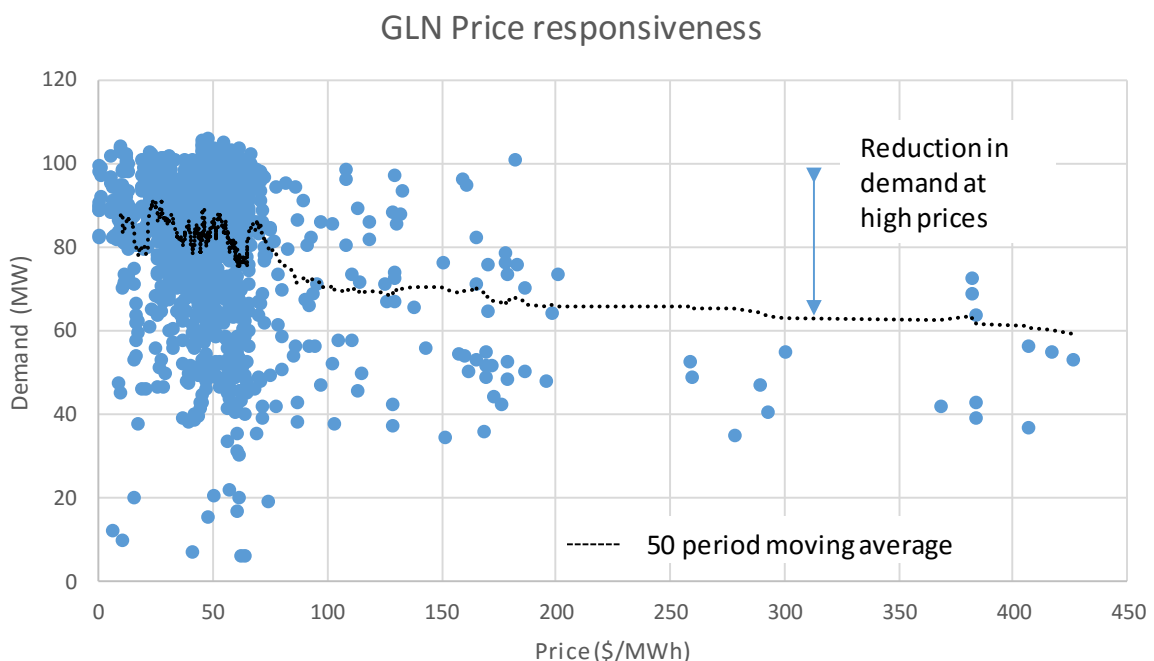
Accordingly, even though the load may respond less during RCPD periods under the TPM changes, no impact on capacity margin is expected because this load is already an unreliable source of DR at peak times.

**Figure 17 - TNG1101 demand response during RCPD periods in June 2015**



By contrast, GLN0331 appears to reliably respond during RCPD periods. A key issue therefore is whether it would be likely to respond in future to nodal prices. Figure 18 explores this issue by showing the actual load and prices (noting that bids are not a good guide, as all load is bid at \$10,000/MWh). Figure 18 shows that a portion of the load at this GXP does respond to nodal prices, with demand reducing when prices rise above roughly \$200/MWh.

**Figure 18 - Glenbrook demand and nodal price**

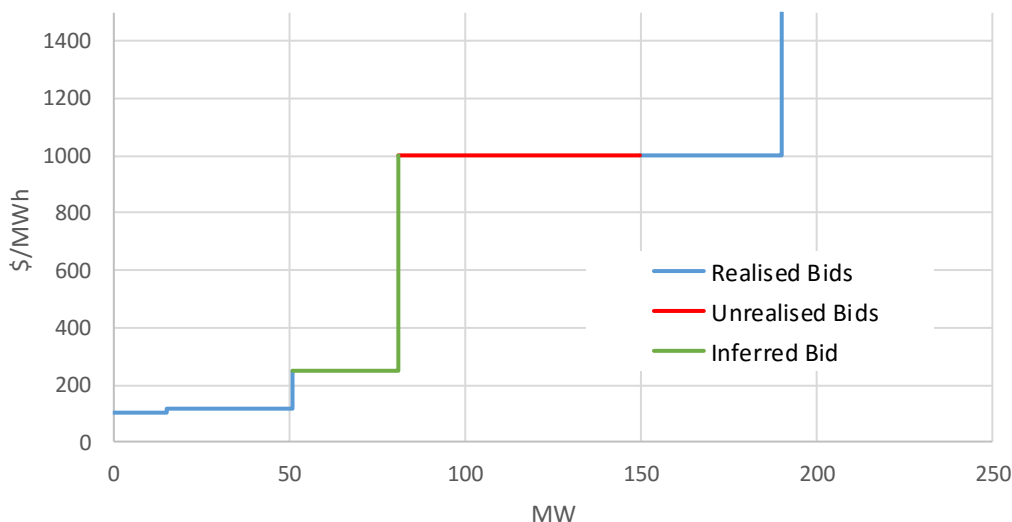


The bid information from Table 9 (and inferred behaviour from Figure 18) can be used to develop a nodal price response curve for major industrial load. This is shown in Figure 19. It is represented as a



'supply curve of DR',<sup>66</sup> because we are most interested in the amount of demand that responds to nodal prices between about \$100/MWh (the observed average nodal price in system peak periods) and about \$1,200/MWh (the approximate level of the RCPD signal).

**Figure 19 - Inferred nodal price response curve for major industrial user demand that reacts to RCPD**



The key observations from Figure 19 are:

- Around 10 MW of load is expected to respond at prices of around \$100/MWh – this tranche is not expected to be affected by the TPM changes, because nodal prices alone should be sufficient to induce demand response (assuming average nodal prices in RCPD periods are similar to historic levels of ~\$100/MWh, or more).
- Similarly, there is about 40 MW of load that has responded in RCPD periods, and that has also indicated that it will respond if nodal prices exceed approximately \$150/MWh. A small elevation in nodal price would result in this load switching off, and therefore no material change in behaviour is assumed.
- A 30 MW tranche that responds between \$200/MWh and \$300/MWh is assumed to respond during some tight system periods, but not reliably so. This tranche has been de-rated and is assumed to reduce the system margin contribution by 10MW in this analysis.
- There is a 69 MW tranche (shown in red) of demand, whose bids indicate an intention to curtail at \$1,000/MWh. However, this load has not responded at such prices or in RCPD periods in the past, and no change in response is assumed for the future.
- Finally, there is a 40 MW tranche of load that responds in RCPD periods, and indicates that nodal prices must exceed \$1,000/MWh before it will curtail. This tranche is assumed to no longer reliably respond in RCPD periods.

In total, the change in demand response from major industrial customers in RCPD periods is estimated at about 50 MW.

<sup>66</sup> Of course it could also be shown as a demand response curve, that slopes downward toward the right. However, it would have a large quantity tranche that has a high price for response, and is not relevant to this analysis.

## Appendix E. Annual security assessment

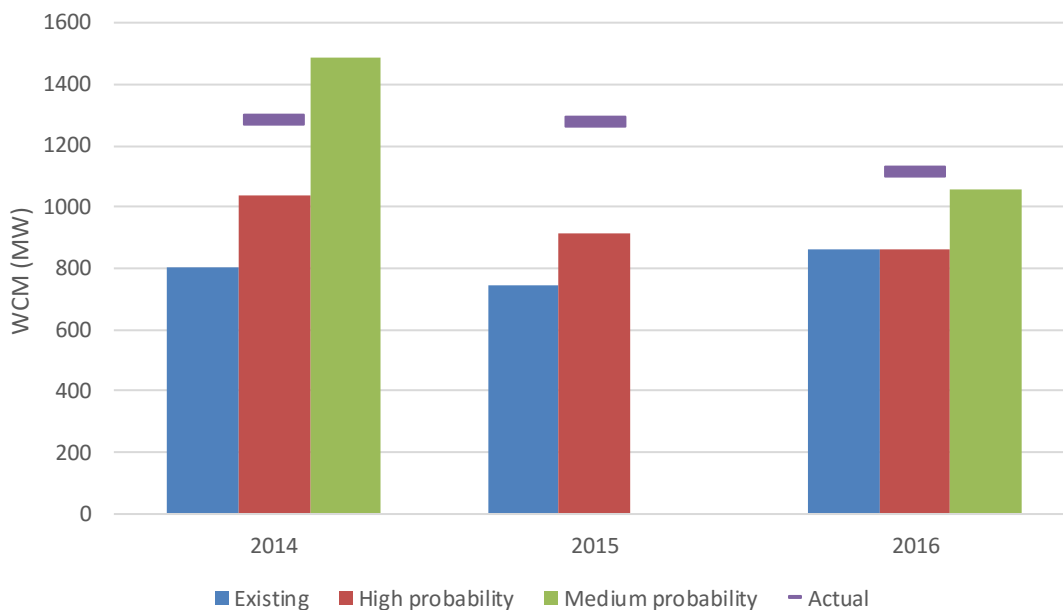
We have used the most recent Annual Security Assessment (ASA) for the calendar year 2019 for this modelling because the TPM changes will affect the system from 2019. The ASA assumes some growth in demand between 2016 and the 2019 year.

If the projected demand level for 2019 were simply compared to current generation capacity, this would not account for additional generation that is likely to be built by that date. For this reason, we have treated the ‘starting point’ generation for 2019 as being current generation, plus committed new build, plus generation categorised as ‘high probability’ for commissioning by 2019. We have also considered the possibility that some ‘medium probability’ generation will be built, and as such have presented the projected winter capacity margin as a band.<sup>67</sup>

We have tested whether this approach is reasonable based on history – i.e. whether generation categorised as ‘high probability’ or ‘medium probability’ for commissioning three years ahead was built. The ASA has been published since 2011, and so it is possible to undertake this comparison for ASAs with actual data for the years 2014, 2015 and 2016.<sup>68</sup>

Figure 20 shows this information. It compares the winter capacity margins predicted in the ASA three years beforehand to the actual WCM calculated at the start of that year.<sup>69</sup> It shows that the WCM consistently turns out to be higher than the ‘existing’ or ‘high probability’ scenarios, and that the ‘medium probability’ scenario may be a better prediction.<sup>70</sup>

**Figure 20 - Three year ahead projection of WCM**



<sup>67</sup> See Figure 1, Figure 2, and Figure 3.

<sup>68</sup> 2019 is three years in the future for the 2016 ASA.

<sup>69</sup> For example, the 2014 values for ‘existing’, ‘high probability’ and ‘medium probability’ are from the 2011 ASA, while the ‘actual’ value is from the 2014 ASA.

<sup>70</sup> Unfortunately, the data was not available for the ‘medium probability’ scenario in the 2012 ASA.