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

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## 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.

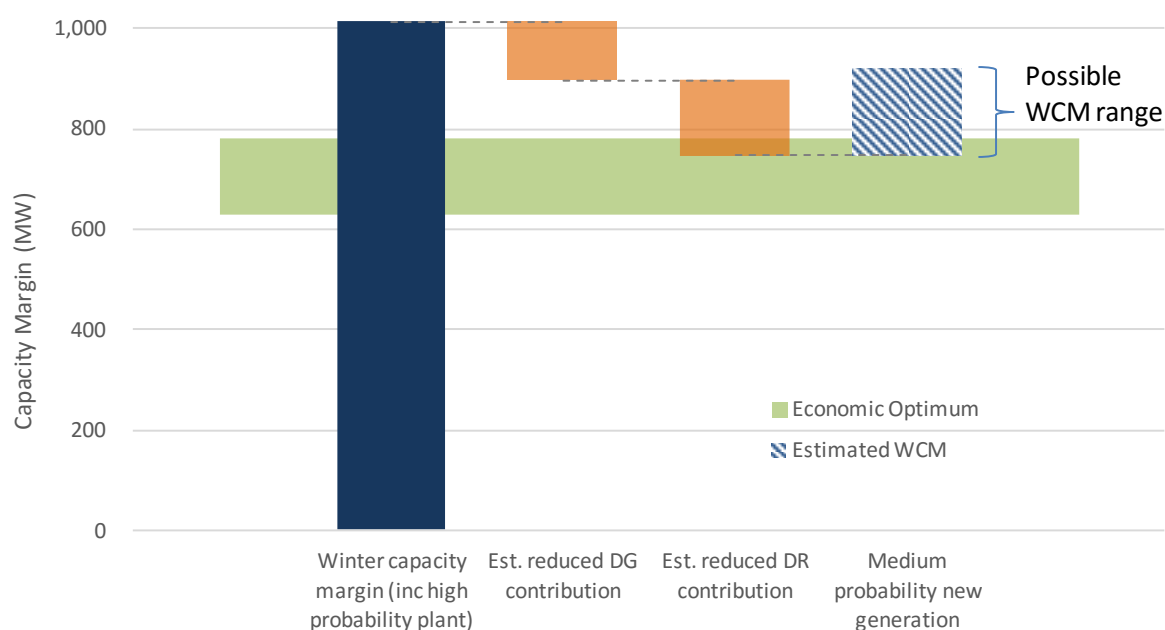
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<sup>1</sup> We use the term 'DG' here, but more correctly, we are looking at physically embedded and notionally embedded generation. We are including the latter because notionally embedded generation is likely to receive Avoided Costs of Transmission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

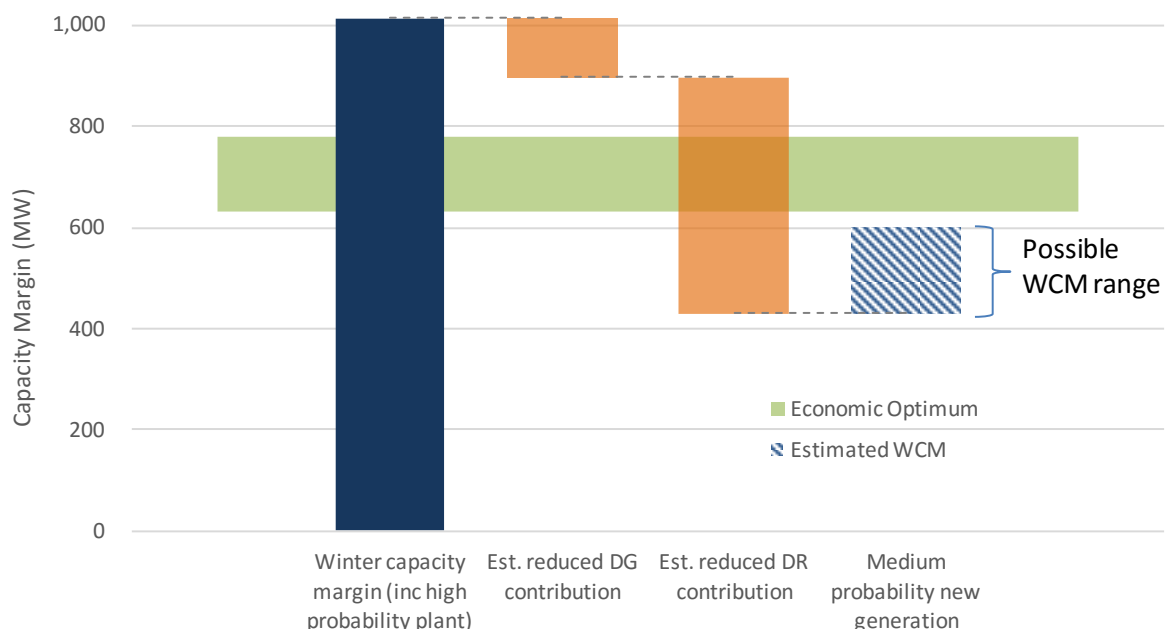
<sup>2</sup> CY 2019 is considered because the earliest that the assumed TPM changes could have effect is the September 2018 to August 2019 capacity measurement period. The DGPP changes are assumed to take effect earlier, but these do not affect DR and we expect them to have a relatively modest effect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

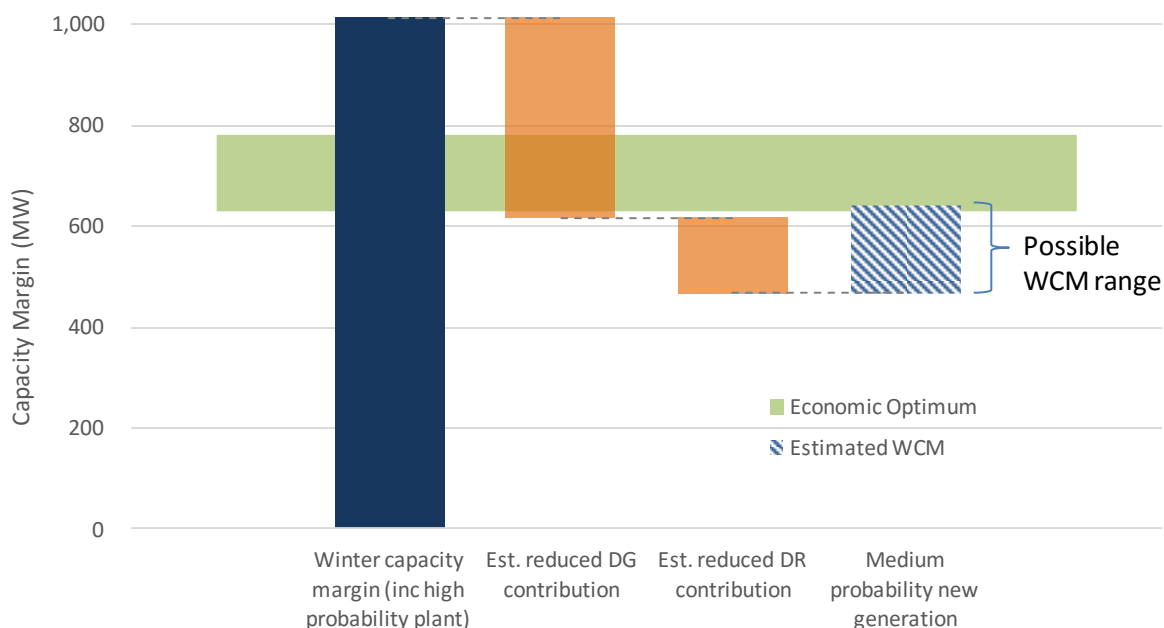
In this case, we assume a 400 MW reduction in the firm capacity contribution from DG. This is roughly twice the observed difference between average DG output in RCPD periods, and the 100 hours of lowest DG contribution across a year.<sup>5</sup>

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:

<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.

<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.

<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**

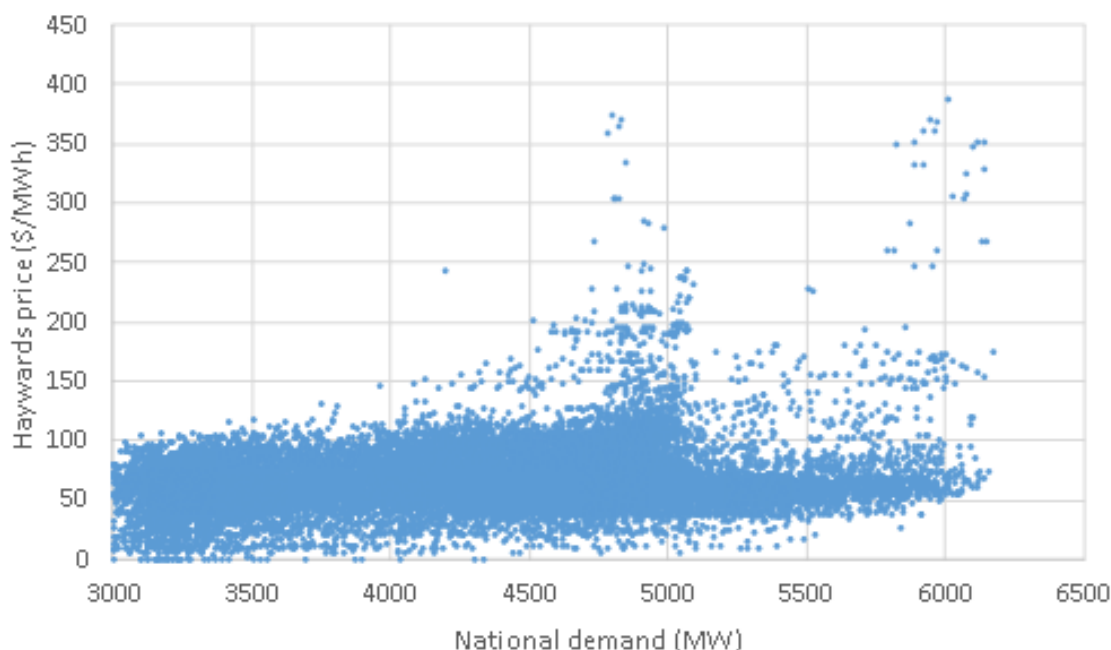
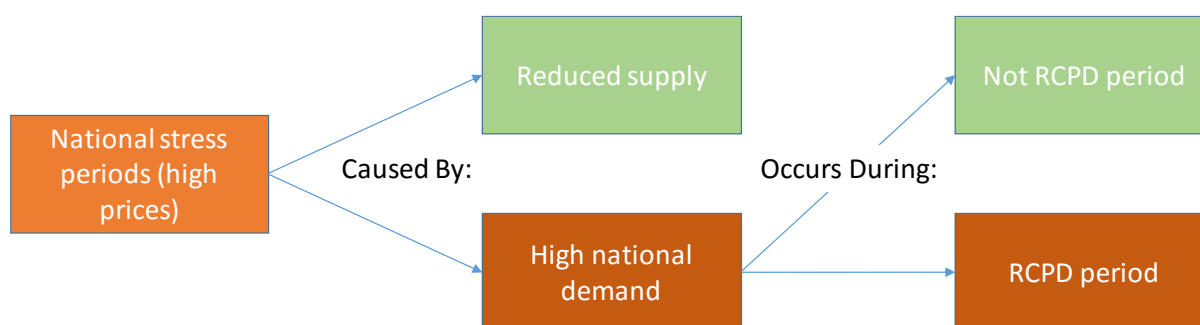


Figure 4 shows that nodal prices were generally higher when national demand was elevated. However, it also shows that tight system periods (indicated by the highest nodal prices) were not always associated with peak national demand periods. Furthermore, RCPD periods do not strictly coincide with times 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**

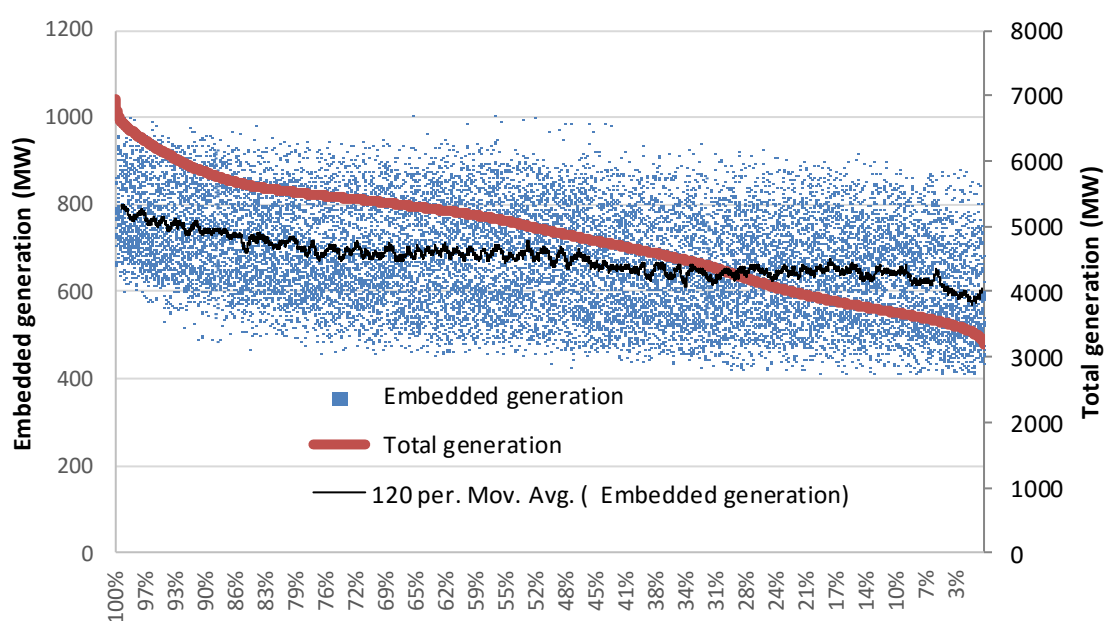


Figure 6 also shows that DG's proportion of total generation generally *decreases* during high demand periods.

## 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 ‘notionally 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
Totals		1,510	941	570	

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*

Demand response		Estimated Capacity (MW)
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>

<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

<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

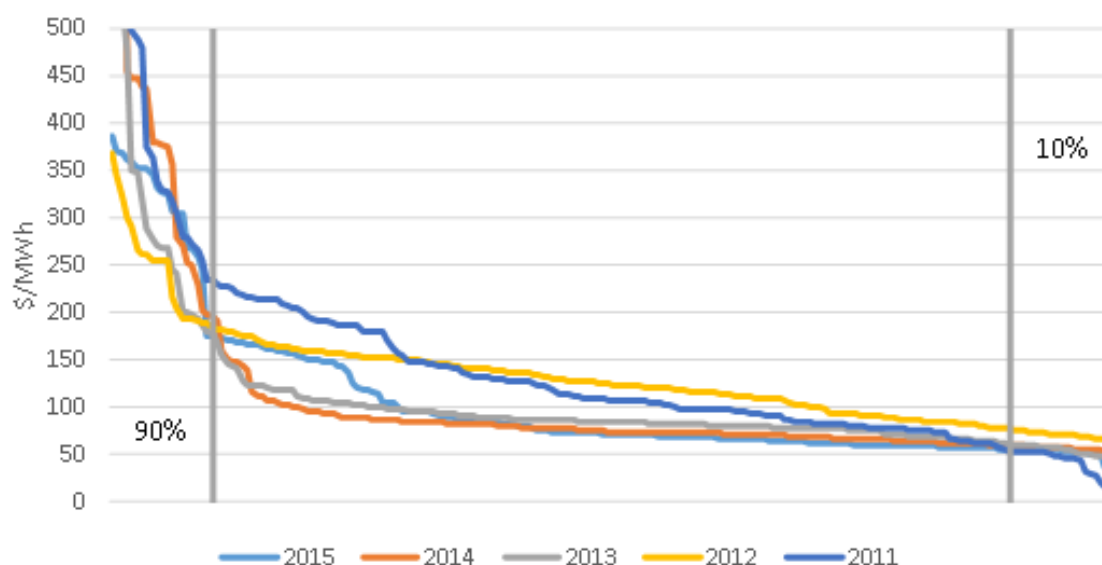
In addition to transmission-related incentives, many DG and DR resource providers are exposed (directly or indirectly) to price signals from the wholesale market. The mechanisms include:

- 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

<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>

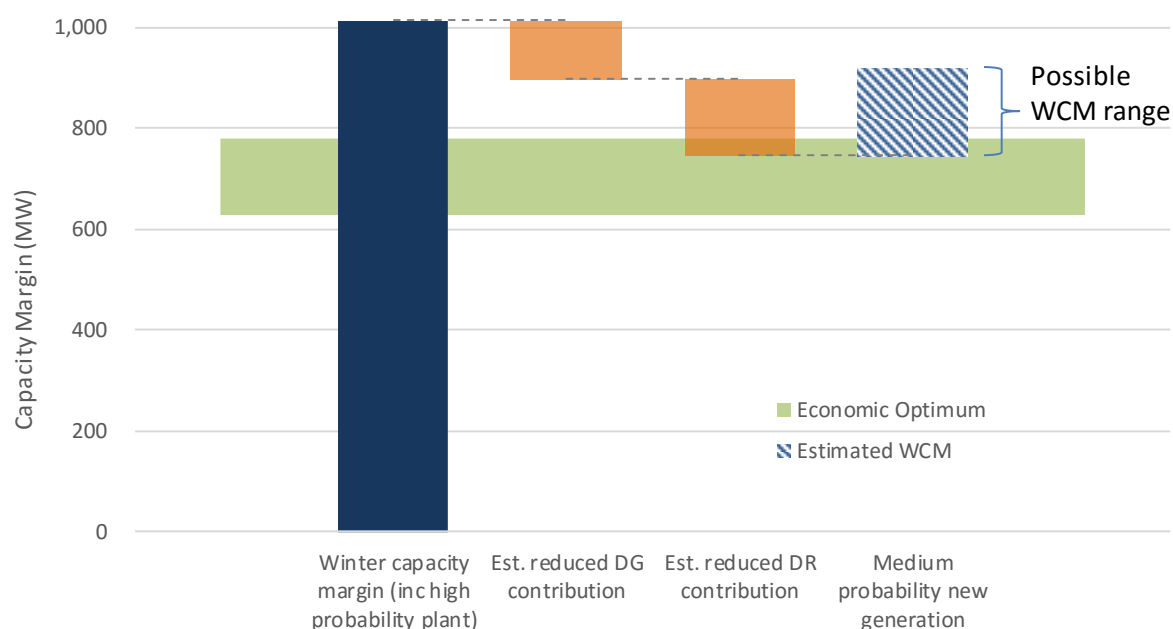
The assessed economic optimum level of the capacity margin is highlighted in green. This is the amount of capacity that is expected to minimise the sum of generation plant costs and shortage costs. If the WCM falls below the optimum level, the expected level of costs from shortages would be higher than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



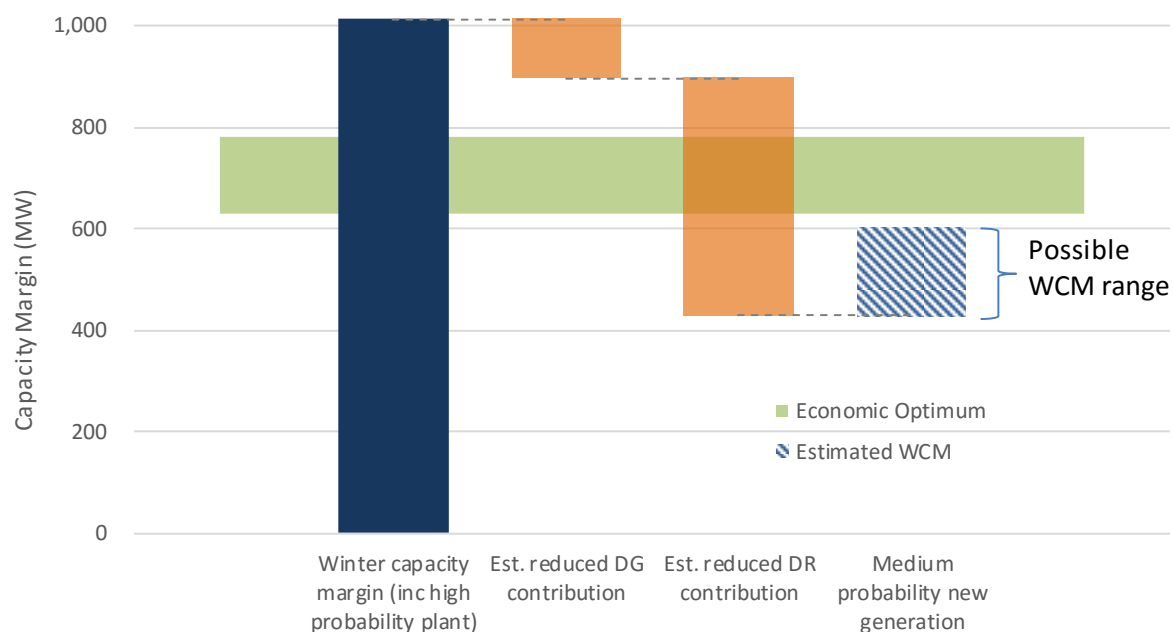
## 4.2 Winter Capacity Margin 2019 - Sensitivity case 1

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.

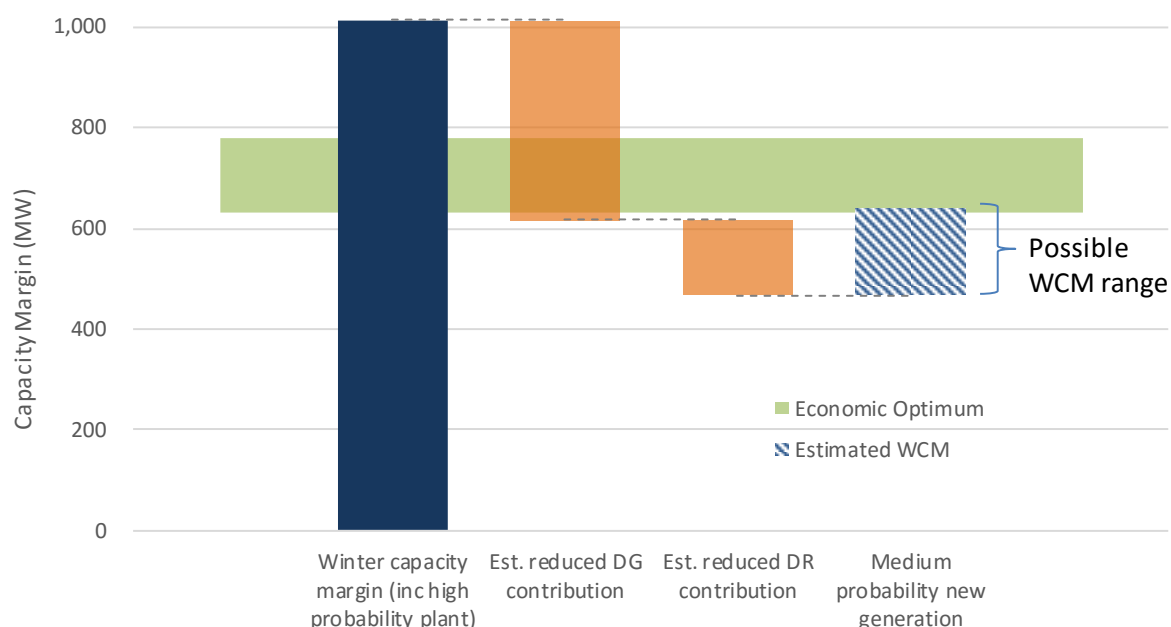
<sup>54</sup> The exception is ripple control which can participate in the reserves market. However, this is a subset of ripple control DR.

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

<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.

<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**

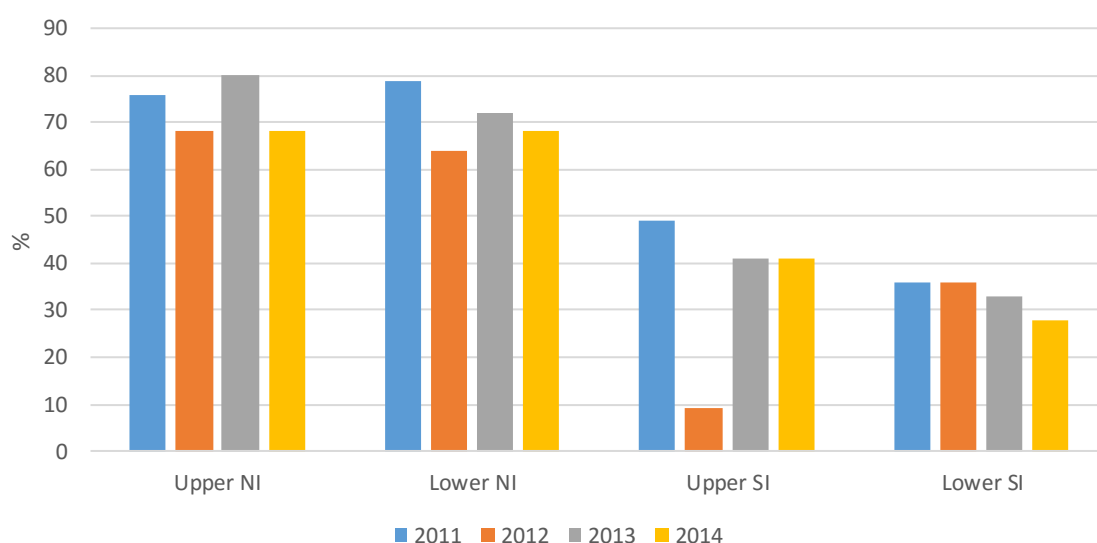
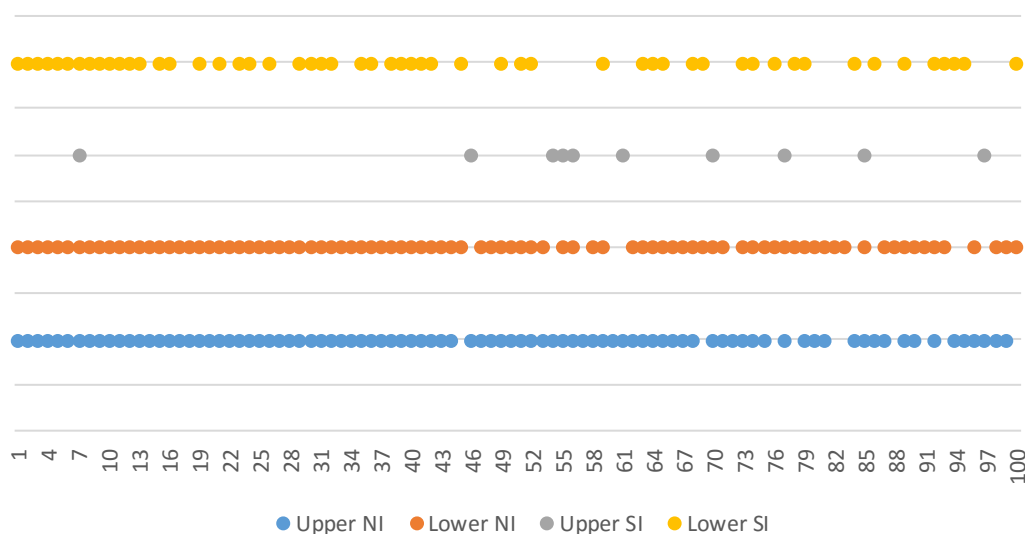


Figure 12 and Figure 13 show national peak periods, with the highest demand period represented by '1' and the 100th by '100'. A coloured dot means that that period was an RCPD one for the region.

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



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

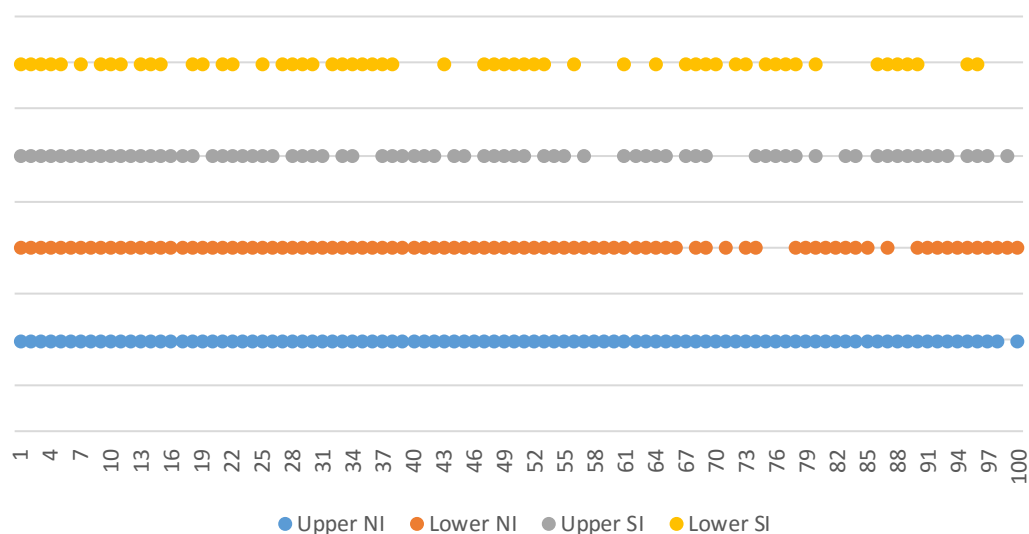
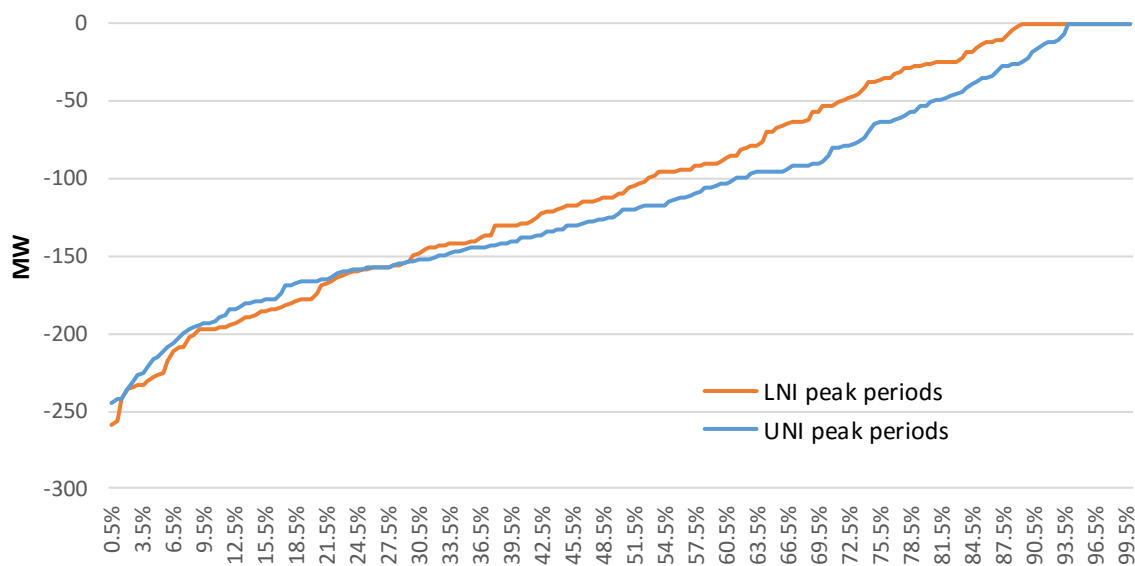


Figure 14 shows that during RCPD periods the HVDC is rarely constrained (by thermal capacity or North Island reserves), the vertical axis being spare capacity, the horizontal axis showing the top 100 RCPD periods). In only about 10% of RCPD periods was the HVDC constrained. This is important because 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

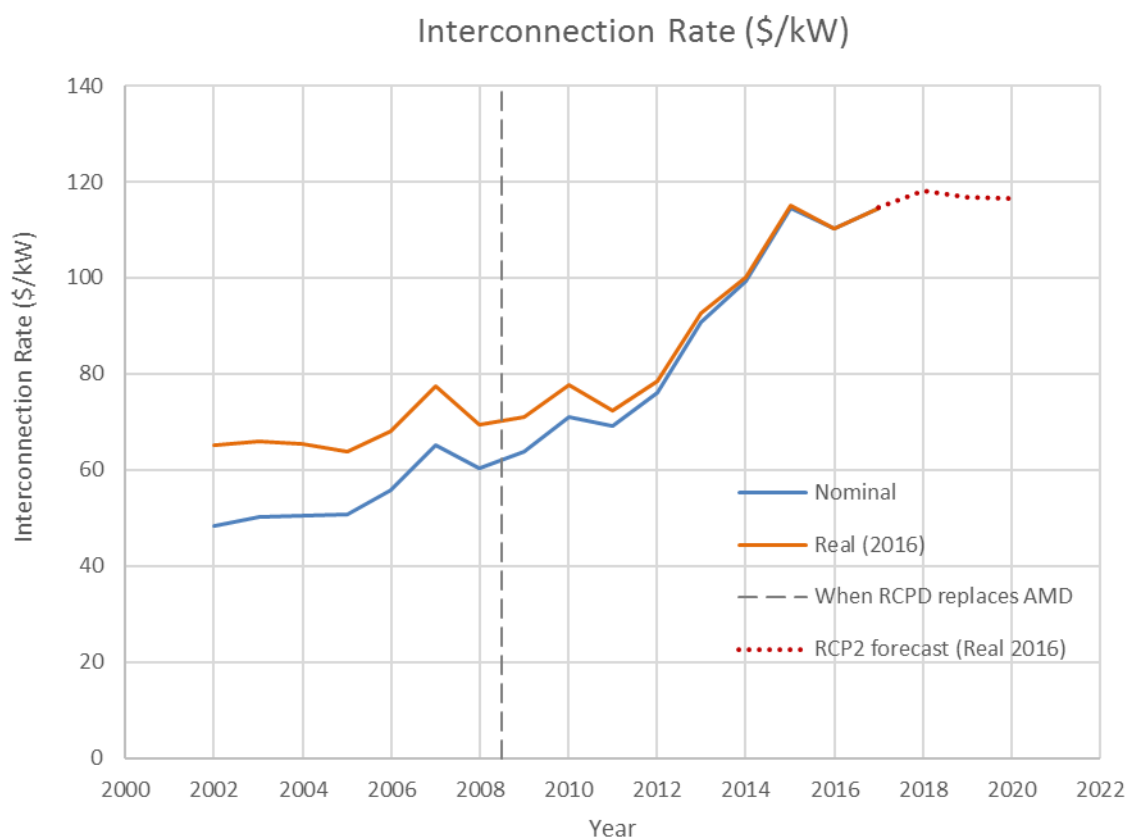
There are a variety of existing and possible price signals that influence the magnitude of GXP consumption at times of peak demand (and hence incentives to activate DG or DR resources). The range of price signals is outlined in Section 3 above. Here we look into a subset of those in detail, namely:

- 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.

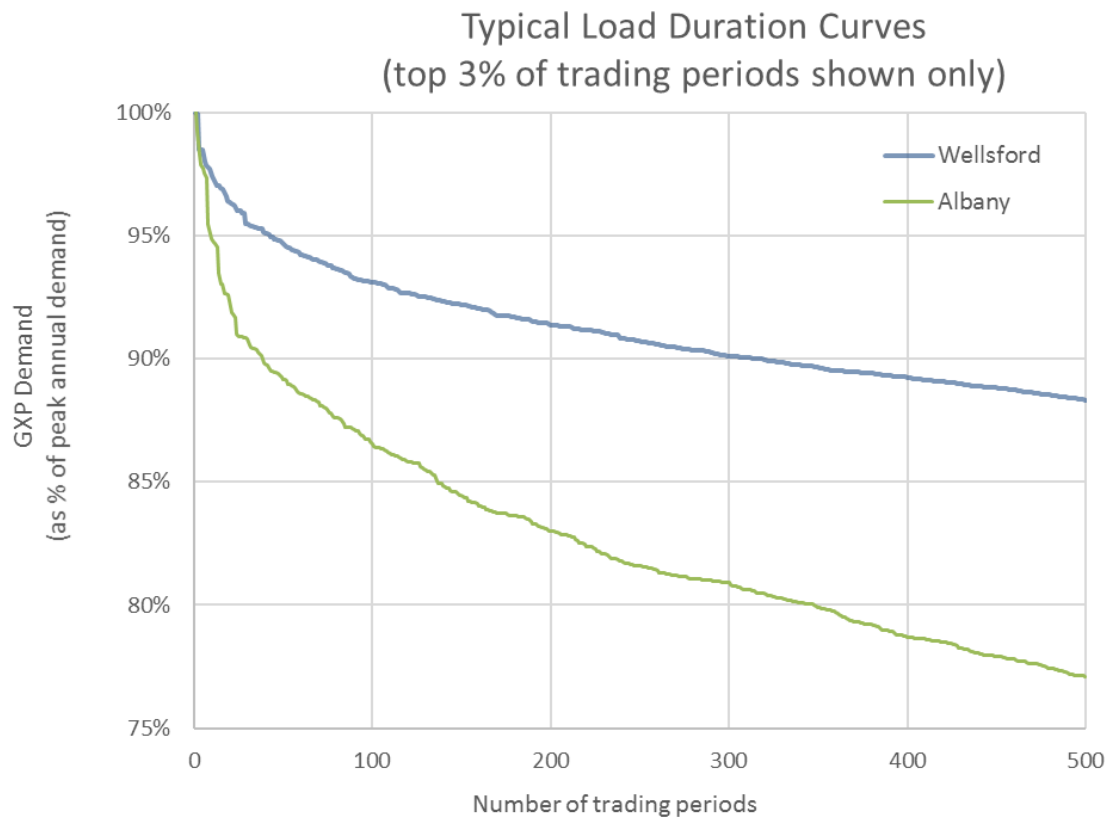
**Table 8 - Indicative strength of the AoB price signal**

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.

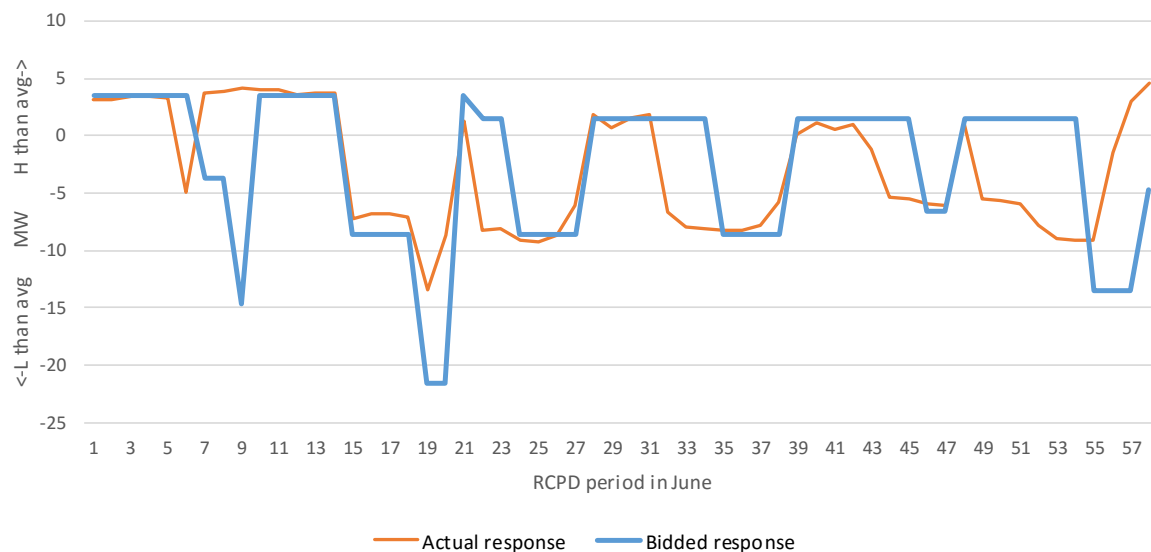
Table 9 - Industrial user demand

	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.

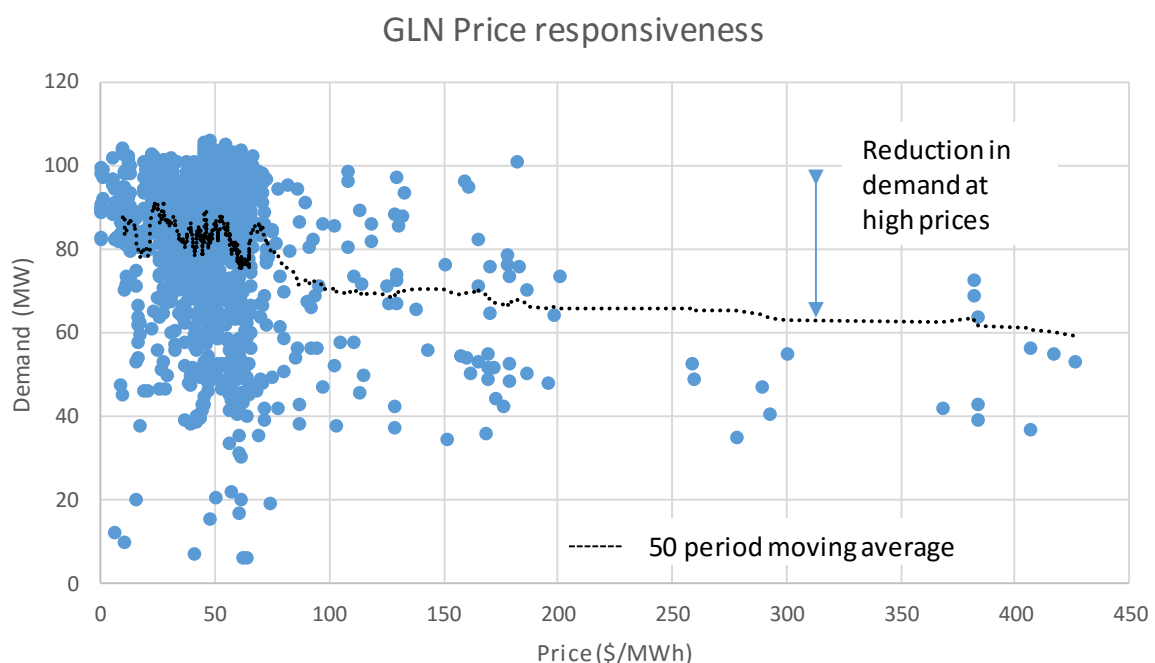
Accordingly, even though the load may respond less during RCPD periods under the TPM changes, no impact on capacity margin is expected because this load is already an unreliable source of DR at peak times.

**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.

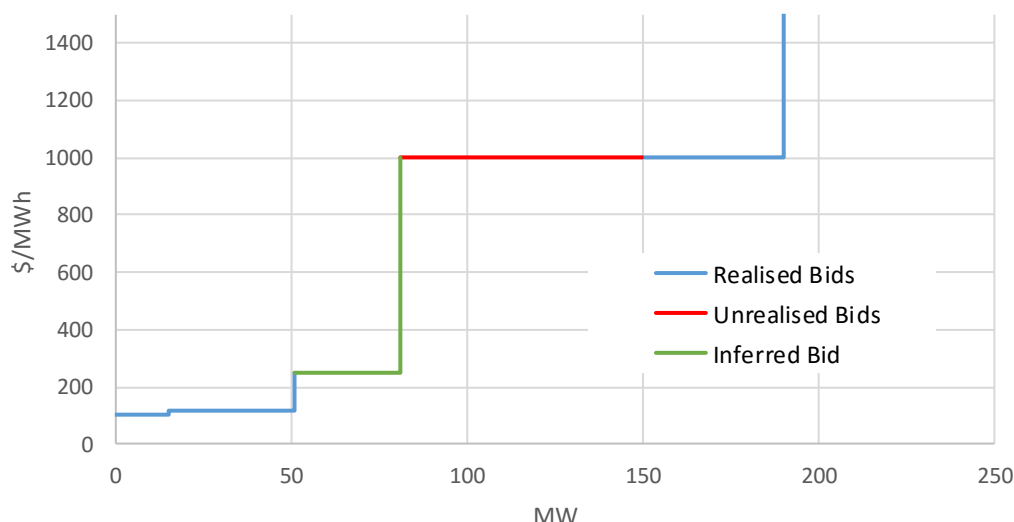
**Figure 18 - Glenbrook demand and nodal price**



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

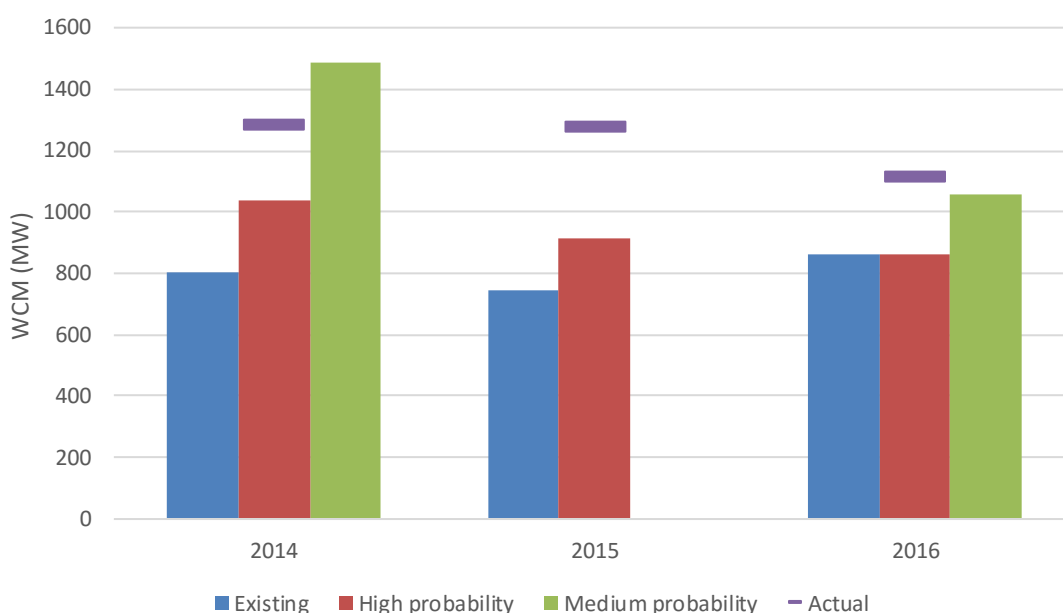
We have used the most recent Annual Security Assessment (ASA) for the calendar year 2019 for this modelling because the TPM changes will affect the system from 2019. The ASA assumes some growth in demand between 2016 and the 2019 year.

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.