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Winter capacity margin – potential effect of possible changes to transmission pricing

Prepared for the Electricity Authority

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Glossary

ACOT	Avoided Costs of Transmission
ASA	Annual Security of Supply Assessment
Authority	The Electricity Authority
Code	Electricity Industry Participation Code 2010
CY	Calendar year
DG	Distributed Generation
DR	Demand Response
EDB	Electricity Distribution Business (a 'lines' or 'network' company)
EMI	Electricity Market Information website, produced by the Authority
FIR	Fast Instantaneous Reserves
GJ	GigaJoule (a unit of measurement of energy)
GXP	Grid eXit Point
HWC	Hot Water Cylinder (electrically heated domestic water storage cylinder)
HVDC	High Voltage Direct Current (the inter-island transmission link)
ICP	Installation control point (a unique identifier for connections to gas or electricity networks)
IL	Interruptible Load
IR	Instantaneous Reserves
kW	KiloWatt (a unit of measure of instantaneous power)
LNI	Lower North Island
LSI	Lower South Island
MW	MegaWatt (a unit of measurement of instantaneous power)
MWh	MegaWatt-hour (a unit of measurement of energy)
NI	North Island
PRS	Price Responsive Schedule
RCPD	Regional Coincident Peak Demand
Ripple control	A technology used to control the HWCs
RTP	Real Time Pricing
SI	South Island
SIR	Sustained Instantaneous Reserves
SRMC	Short Run Marginal Costs
TPM	Transmission Pricing Methodology
TPR	Transmission Planning Report
UNI	Upper North Island
USI	Upper South Island
WCM	Winter Capacity Margin (a measure used in the ASA)
WEM	Winter Energy Margin (a measure used in the ASA)
WUNI	Waikato and Upper North Island

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). The assessment focusses on how the changes may impact on the winter capacity margin (WCM) for 2021 and uses Transpower's most recent Annual Security of Supply Assessment (ASA) as the foundation. The WCM reflects the supply demand balance in the North Island, and we do not consider the effect on local situations.[1]

We estimate the installed capacity (and likely capacity contribution) of distributed generation (DG)[2] and available demand response (DR) under the status quo arrangements. We then assess how the operation of DG and DR could change, based on the incentives providers would face if TPM changes 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 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 most DG plant to be 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 recent nodal prices during most peak periods. The base case projects a reduction in capacity contribution for this plant of 128 MW. We have also assumed that some non-offered hydro DG with storage may not respond to spot prices because these provide a less predictable price signal than RCPD charges. We have assumed half of this resource (21 MW) will no longer respond during peak periods.

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 44 MW. We also assume a 44 MW reduction in DR from commercial and smaller industrial users.

In relation to ripple control of hot water heating, we project a net reduced DR contribution of 95 MW (around 15% of current DR contribution from ripple control).

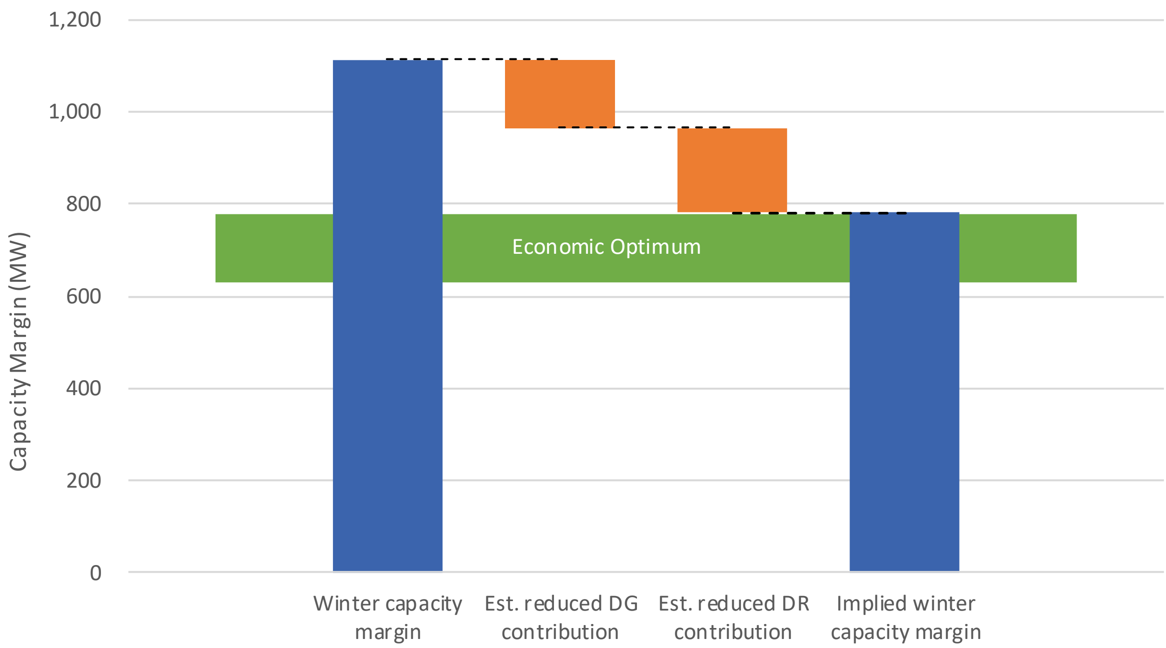
In aggregate, these effects would reduce the projected winter capacity margin for 2021[3] based on existing and committed plant by around 332 MW, to a new level of 782 MW, as shown by Figure 1. This is at the upper end of the estimated optimum economic range for the winter capacity margin.

[1] Except briefly in section 5.2 when commenting on Transpower's analysis.

[2] 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 may receive Avoided Costs of Transmission payments (ACOT) and therefore be affected by changed to transmission pricing.

[3] CY 2021 is considered because the earliest that the assumed TPM changes could have effect is the September 2020 to August 2021 capacity measurement period.

Figure 1 - Base case projection for 2019 winter capacity margin



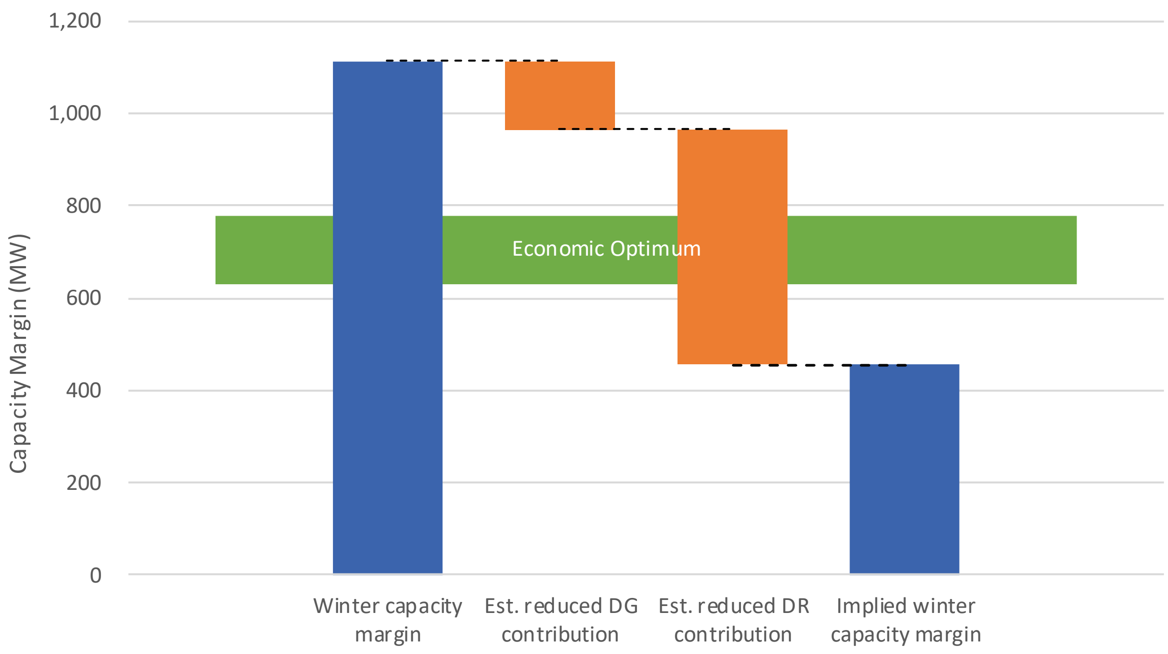
Sensitivity case 1

We have considered a sensitivity case in which there is additional reduction in the net DR contribution from ripple control and major users, 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. In particular, unlike DG owners, EDBs who exercise operational control of ripple relays do not have a direct financial incentive to respond to nodal energy prices at present.

In this sensitivity case, the projected winter capacity margin decreases by around 659 MW. As shown by Figure 2, the resulting 2021 winter capacity margin based on existing and committed plant would be around 455 MW, which is well below the assessed economic optimum range.

In practical terms, a sudden reduction of 659 MW to the capacity margin means that there is a higher chance of not being able to meet demand during a cold winter evening. This increased risk of shortage may not be desirable, even though it may not be significantly different from the status quo on a purely economic basis.

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



Sensitivity case 2

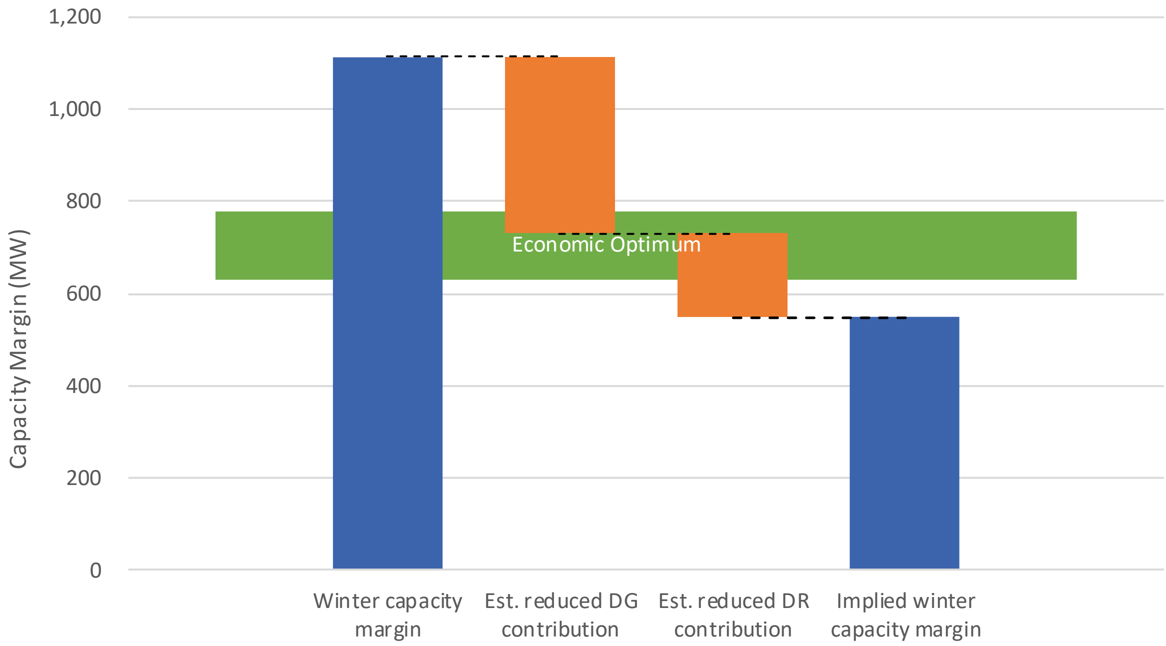
Although we expect the capacity contribution from most DG plant to be unchanged, we have considered a sensitivity case where a sizeable number of non-diesel DG plants restrict their generation levels during tight system periods (foregoing immediate spot revenues), in the belief this will yield future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

In this case, we assume half of available wind and hydro plant choose not to generate, resulting in an additional 234 MW reduction in the firm capacity contribution from DG.

In aggregate, these changes would reduce the projected winter capacity margin for 2021 by around 566 MW. As shown by Figure 3, the resulting winter capacity margin based on existing and high probability plant would be around 548 MW. This is below the assessed economic optimum range.

In economic terms, this means that the cost of unserved energy will outweigh the cost of building more generation capacity. However, the current situation of "over-supply" may also not be optimal since maintaining peaking capacity has an associated cost.

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 3.9. In summary, these are:

- Financial incentives have been robust predictors of DG behaviour to date. Under a change from relying on RCPD-based charges to nodal price incentives,[4] 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 changes.[5] 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

[4] 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 benefit-based charges they will face if an upgrade proceeds.

[5] Such as a misperception held by some parties that the TPM changes would remove all incentives to manage peak grid demand growth.

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), there would be increased incentives for use of ripple control to reduce peak 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) could materially impact upon the ability to maintain reliable supply in peak demand periods.

Under the status quo transmission pricing arrangements, Transpower recovers most of 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 in a year. Embedded generators and DR providers can be strongly incentivised to operate during RCPD periods, as this will reduce the interconnection charge for the host EDB.

We have assumed under the proposed TPM the interconnection and high voltage direct current (HVDC) charges in the current TPM would be replaced. Instead a combination of a benefit-based charge, a capacity-based residual charge and (potentially) a transitional peak demand-based charge would apply. The TPM changes would be broadly as described in the 2019 Issues Paper released by the Electricity Authority (Authority) in July 2019.[6] Our assessment assumes a commencement date for the new TPM of 1 April 2022 (as set out on the 2019 Issues Paper). For the reasons discussed in section 2.2, we do not expect the assessment results to be materially affected by a later commencement date.

1.2 Scope of main assessment

The report focuses on security issues at the aggregate system level. More specifically, the assessment considers:

- 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 changes.

In all cases, the assessment is relative to a status quo where the TPM changes do not come into operation.

1.2.1 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 reliable, comprehensive and 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 consistently in various surveys and public databases, and also due to limited information about contractual embedding agreements which may be relevant to operational incentives.

[6] https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/

- 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.

1.3 Review of 2018 Transpower report on peak pricing

Transpower released "The role of peak pricing for transmission"[7] in November 2018 that outlined its views on the need for a peak-based price signal in addition to nodal prices.

Transpower's report was in part a response to Concept's 2016 report on the effect of TPM changes on the WCM,[8] which this report updates. The methodology used in this 2020 report is not fundamentally different to that used for the 2016 report, and as such we also review Transpower's analysis and briefly address Transpower's feedback.

Transpower's report[9] also considered the impact of removing RCPD on transmission investment requirements in the upper North Island and upper South Island regions. While we do not have the capacity to perform the regional power flow analysis required to properly model voltage constraints, we have briefly reviewed their assumptions and commented on their conclusions.

[7] www.transpower.co.nz/sites/default/files/plain-page/attachments/Transpower_The_Role_of_Peak_Pricing_for_Transmission_2Nov2018.pdf
[8] Winter capacity margin – potential effect of possible changes to transmission pricing and distributed generation pricing principles – December 2016.
[9] ibid

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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 (ASA) was published in February 2019.[10]

The ASA 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. The standards are intended to represent the economically optimum level of supply – i.e. the range where the *combined cost of generation and involuntary power outages is minimised*.

In this report, we assess the potential effect of the TPM changes on the predicted system security margins in Transpower's latest ASA. 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 ASA covers the period 2019-2028. The Authority's 2019 Issues Paper posited the new TPM coming into effect on 1 April 2022. If that occurs, there will be no RCPD-based transmission price signal applying to peak demand during the winter of 2021, even though the existing TPM will still apply. Instead, RCPD charges for the 2021 transmission year will be based on participant behaviour in earlier periods.[11] However, even though the new TPM would not apply directly in 2021, participants would be cognisant of the design of the new TPM and adjust their behaviour.[12] This means 2021 would be the first year that we would expect behaviour to change as a result of adopting a new TPM. Accordingly, we have used the ASA data for 2021 as our starting point.

While we base our calculations on forecasts for 2021, we do not expect results to be particularly sensitive to the exact year of the implementation of the TPM changes. This is because the near-term[13] winter capacity margin has been relatively stable through time. For example, the near-term margin has ranged between 1050 MW and 1200 MW in the past 6 years and is projected to be around the middle of that range in 2021.[14] Hence, we expect the projected 2021 conditions to represent a reasonable 'starting point' from which to assess the effect of potential TPM changes.

We expect the risks of excessive supply shortage to be lower in subsequent years because the market will respond to changes in supply and demand. 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

[10] See https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/SoS%20Annual%20Assessment%202019%20report.pdf

[11] The capacity measurement period, upon which charges for the 2022 transmission year would be based, will run from 1 September 2020 to 31 August 2021 for the Upper South Island region. For pricing in other transmission regions, the measurement period excludes the November – April months in this period.

[12] i.e. participants would be aware that they may be charged for any future transmission investments that benefit them.

[13] This refers to the forecast winter capacity margin from each ASA for one to two years in the future. Many generation plants have construction times of about this duration, so generation plant that will be constructed in this time-frame is considered "committed". For winter capacity margins further in the future, forecast demand growth typically exceeds committed plant, causing an apparent drop in the margin even though history indicates that it is highly likely that further generation plant will be built in future to meet the projected increase in demand.

[14] Forecast winter capacity margins for one year ahead have been extracted from previous annual security assessments.

new resources into operation. Accordingly, nearer term security impacts are likely to be more material than longer term effects.

We note that if a material unexpected adverse shock were to occur (such as loss of a large power station), the projected conditions for 2021 in the ASA may no longer form a reasonable starting point for this assessment. However, at the time of writing we have no reason to expect any such event to occur.

2.3 Focus on winter capacity margin

The ASA considers security from the perspective of:

- The Winter Capacity Margin (WCM) – the ability to serve North Island 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 national demand during a prolonged drought or similar supply contingency.

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

- The RCPD signal only affects behaviour for about 100 hours a year,[15] meaning its effect on energy-related decisions (such as hydro storage and thermal fuel management) is relatively small.[16]
- 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 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 changes, given that nodal prices are expected to be elevated during such periods.

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

The WCM is calculated according to a formula set out in the Security Standards Assumptions Document (SSAD)[17] 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 higher margin the risk of shortages during peak periods will be lowered, but there will be a higher cost from having additional generating plant available. With a lower 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[18].

[15] The RCPD periods are not known with certainty until the end of the measurement year. As such, we have assumed that a participant would respond in about 200 trading periods to try to target the actual 100 peak trading periods.
[16] For example, 200 MW of extra demand for 100 hours only amounts to 20 GWh, or about 1% of typical winter hydro storage.
[17] See https://www.ea.govt.nz/operations/wholesale/security-of-supply/security-of-supply-policy-framework/security-standards-assumptions/
[18] See www.ea.govt.nz/our-work/consultations/sos/winter-energy-capacity-security-supply-standards/submissions/

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,[19] or in the extreme, forced power outages may occur. 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.[20]

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

2.4 Steps in assessment process

The approach to assessing the incremental impact of the TPM 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 2021, including allowances for the following:
    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 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 1-4, and deduct a corresponding capacity allowance from the projected WCM for 2021 in Transpower's latest ASA
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.

2.5 Current TPM price signal does not necessarily coincide with tight system conditions

Before applying the steps in the assessment process, it is useful to distinguish between national and regional impacts.

Under the current transmission pricing regime, parties are heavily incentivised to respond (increase generation or decrease load) during periods of high *regional* demand. However, it is important to recognise that in New Zealand, tight system periods are not always associated with high *national* demand, let alone high *regional* coincident peak demand periods. Figure 4 shows nodal prices (an indicator of system stress) and national power demand. 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 or wind generation.

[19] Increasing the likelihood of load shedding being required to cover a contingent event
[20] See www.ea.govt.nz/dmsdocument/14134

Figure 4 - Nodal prices and national demand – 2017-2019

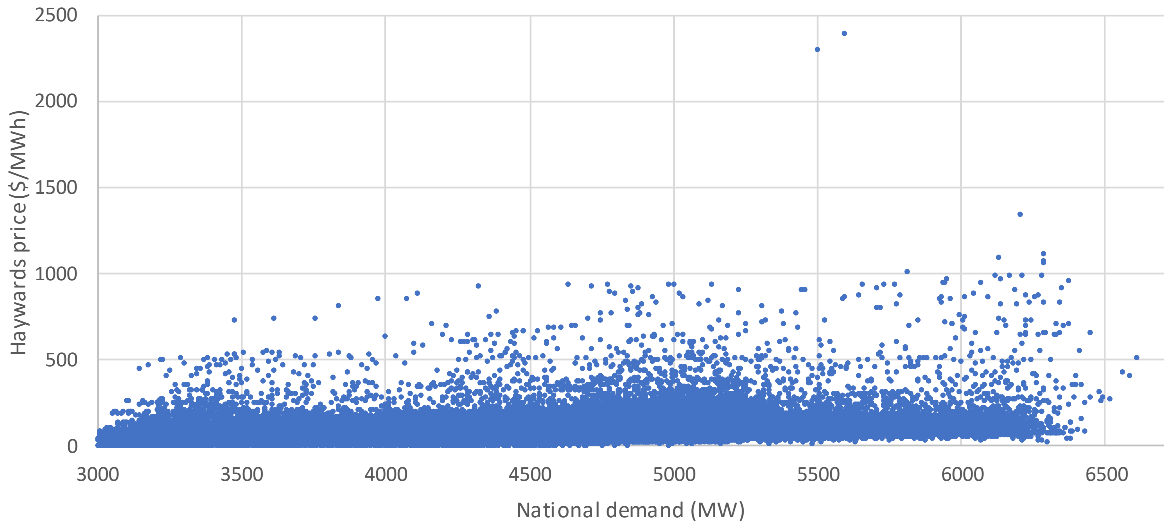


Figure 4 shows that nodal prices were generally higher when national demand was elevated. However, it also shows that tight system periods (indicated by the highest nodal prices) were not always associated with peak national demand periods. Furthermore, RCPD periods do not strictly coincide with times of peak national demand[21] – 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

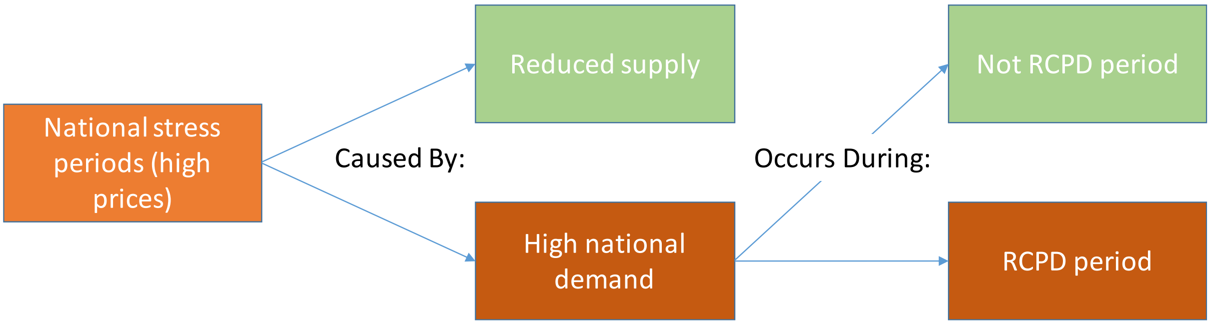
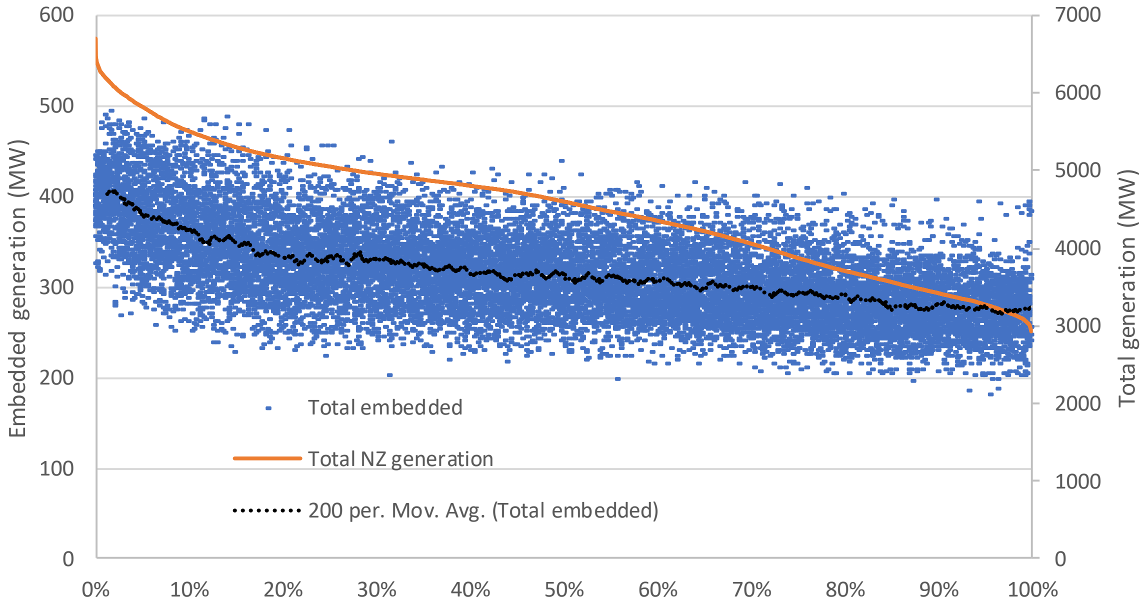


Figure 6 shows the total output from large, non-wind DG at different levels of national demand.[22] There is limited half-hourly data for smaller DG, so the analysis is confined to stations that are large enough to be separately metered. Three things are apparent from the graph:

- There is almost always at least 200 MW of DG.
- DG output increases slightly as national demand increases. The average DG generation during the 200 highest demand periods is about 80 MW higher than during all periods.
- There is a large amount of 'noise' at all demand levels. Generation varies by about +/- 120 MW at all levels of national demand.

[21] 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.
[22] Strictly speaking, this is national generation, which is national demand plus losses.

Figure 6 - Embedded generation and total generation (YE November 2019)



This suggests there is some increase in output from DG during national peak demand periods, perhaps due to the correlation with the RCPD signal. To test this, we repeated the above analysis, but instead of comparing DG output during the 200 highest national demand periods, we compared it to the 200 likely RCPD periods (i.e. highest *regional* demand periods) and the 200 periods with the highest price.[23]

Figure 7 - Large DG output during different "peak" periods

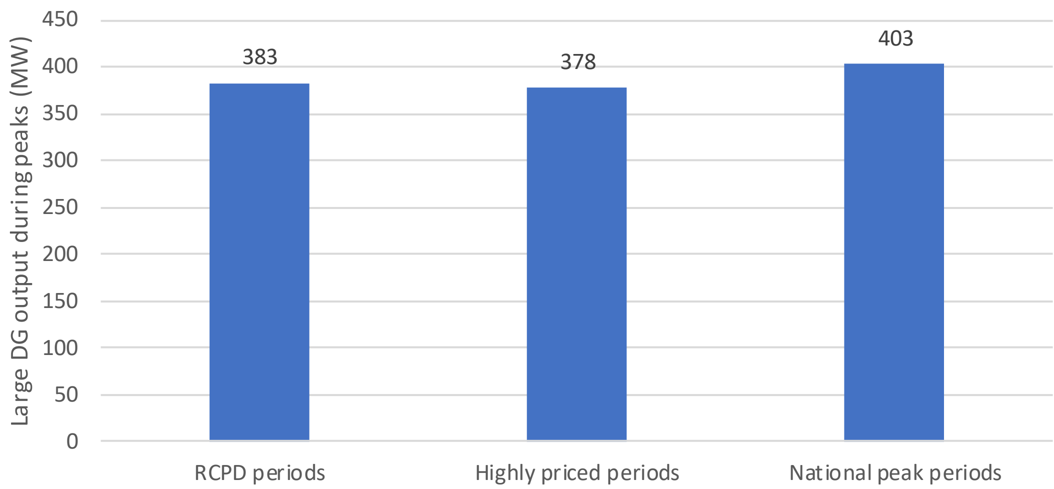


Figure 7 shows that DG responds more strongly to national peak demand than regional peak demand. It also shows that DG responds similarly to spot prices as it does to regional peak demand. Taken together, these results suggest that DG behaviour is not dominated by RCPD incentives, and therefore we don't expect a significant change from these plant in the absence of an RCPD signal.

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

[23] To ensure that generators were responding to high spot prices and not the RCPD signal, we used the 200 highest priced non-RCPD periods.

2.6 Estimated physical capacity of distributed generation plant

Changes to the TPM will affect distributed generation primarily by removing or reducing the size of ACOT payments. Any generation that may be in receipt of ACOT payments is therefore relevant for our analysis. This includes generation connected directly to EDB networks and "notionally embedded" generation.[24] For brevity, we refer to both as DG in this paper.

Although recent Code changes mean that some DG is no longer eligible for regulated ACOT payments,[25] pre-existing contractual arrangements may mean that some such plant is nonetheless still receiving ACOT related payments.

Because we have no detailed plant-level information on ACOT payments, we have instead focussed on whether plant *may* be in receipt of ACOT payments (i.e. it is connected to a distribution network or is notionally embedded).

Based on this criterion, we estimate the DG installed capacity to be approximately 1650 MW. This nameplate capacity estimate primarily comes from the Authority's Electricity Market Information (EMI) database. We have separated some hydro generation further using additional data sources (primarily the Authority's 'existing generation' data set) and industry knowledge because we expect the different types to respond differently to the TPM changes.

Table 1 - Summary of the DG nameplate capacity

Distributed generation		**Estimated Installed Capacity**			**Main drivers of plant SRMC**
		MW	**Inflexible**	**Flexible**	
Thermal	Diesel	128		128	Operating costs and fuel costs
	Gas	87		87	Operating costs and gas costs
Hydro	Offered storage	486		293	Water opportunity cost & operating costs
	Non-offered storage			42	Water opportunity cost & operating costs
	Run of river		151		Operating costs
Wind		362	362		Operating costs
Cogen		142	142		Generation-related operating costs
Geothermal		229	229		Operating costs
PV		112	112		Operating costs
Bio	*(landfill gas)*	73	73		Operating costs
Other		34	34		Unknown
	Totals	**1,651**	**1,103**	**549**	

As discussed in Appendix A, the assessed peak capacity contribution for some DG is de-rated below the nameplate capacity. For example, the ASA 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 66 MW compared to nameplate capacity. Where applicable, we have adopted the derating values used in the 2019 ASA when considering the effect of DG not operating in peak periods.

[24] Generation that isn't physically distributed generation, but which has previously been treated as such for the purposes of ACOT payments because there is an associated Prudent Discount Agreement or Notional Embedding Agreement.

[25] Changes made to Part 6 of the Code in late 2016.

2.7 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.

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

Demand response		Estimated Capacity (MW)
Ripple control	Hot Water Cylinders	644
Grid-connected Major Users	Industrial	44
Other Business Users	Various load types (e.g. cool stores)	44
	Totals	**732**

We emphasise that there is a degree of uncertainty in these estimates, 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. We estimate there is about 644 MW of ripple controlled water heating load available during peak periods. This figure is less than the total nameplate capacity of water heaters subject to ripple control, and takes account of load diversity (some heaters will be off because water is already hot).

This estimate is based on a 2018 Commerce Commission survey of EDBs 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;
- inspection of the observed changes in demand at GXPs with high residential customer numbers during RCPD periods; and
- the results of the 2006 'Existing Capability Survey' undertaken by the then Electricity Commission.

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 C.

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. In the absence of any firm information, we have assumed it is similar to that of grid-connected major users that respond to RCPD signals. We believe this is a conservative estimate[26] 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.

[26] i.e. the actual response will not be more than this.

3 Effect of TPM 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 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	Comment on incentives that arise
RCPD	Removed if the TPM changes proceed	\$98,000/MW per year (or about \$980/MWh during the 200 periods DG or DR would need to operate to hit the RCPD peaks)	Provides a 'blanket' incentive for GXP demand reduction / DG operation, at times of RCPD, irrespective of local or system wide conditions. RCPD signal does not always incentivize response during system stress periods.
Benefit-based charge	Added if TPM changes proceed	Varies dependent upon situation. The potential for a charge could be substantial incentive (of a similar order to the RCPD charge or higher) where near term investments are expected.	Provides signals for GXP demand management when and where required for the purposes of signalling transmission capacity requirements
Possible transitional charge	Possibly to be added if the TPM changes proceed	Yet to be determined	
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.

Peak demand signal	Timing	Strength of the signal or incentive	Comment on incentives that arise
Nodal pricing in energy spot market	Existing arrangements remain in place	Over the top 200 RCPD peaks[27] the average nodal price has been ~$165/MWh. The average of the top 200 highest price periods[28] is about $659/MWh. The large difference is because reductions in supply often cause high prices, not necessarily peak demand.[29] However, the removal of the RCPD transmission signal may lead to higher nodal prices in some peak periods, if a rise is needed to incentivise additional supply or DR.	Provides marginal value of energy and reserve signals at each GXP, taking account of transmission constraints, varying over time.[30] 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 $60/MWh.	

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

This sub-section describes our assumptions of the effect the TPM changes will have on price signals experienced by DG and DR at times of peak demand. These assumptions are intended to cover the likely (base case) and downside (sensitivity cases) that could occur.

Sections 3.3 and 3.5 discuss how these changes to 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 RCPD periods. This arrangement creates a strong price signal to manage GXP demand in RCPD periods, via demand response or operation of distributed generation. This signal is expected to equate to around $980/MWh in 2021, if no change occurred to the TPM.[31]

[27] For the 2020 pricing year. i.e. 2018-10-01 to 2019-09-30 for the upper South Island and 2019-04-01 to 2019-09-30 for other regions.
[28] For 2018-10-01 to 2019-09-30.
[29] For example, e3p and one McKee unit were the only major thermal units available during a high priced period in November 2019.
[30] 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.
[31] This is based on the forecast interconnection rate of $98/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 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.

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.

For the purposes of this report, we assume that under the proposed TPM, participants will face no incentive to limit their peak demand from transmission charges. Strictly speaking, this is not the case because the benefit-based charge can create incentives to limit peak demand. Furthermore, the Authority may include a peak-based charge in the TPM as a transitional element.

Nonetheless, we adopt the assumption noted above for this report so that we can assess the effect of relying on nodal energy prices and reserve prices during times of system stress to manage peak demand periods.

In section 6 we discuss how transitional peak-based transmission charges could affect our conclusions.

3.3 Effect of TPM changes on incentives to operate DG

Some DG qualifies for avoided cost of transmission (ACOT) payments from the EDB to which DG is connected. In broad terms, these ACOT payments reflect the transmission charges avoided by the EDB as a result of DG operation.

Under the current TPM, this mechanism significantly increases the incentive on qualifying DG to operate in regional peak demand periods. The proposed TPM is expected to substantially reduce ACOT payments because of the removal of the RCPD-based charge.

Identifying how each DG will be affected by a TPM change is not straightforward because of the range of mechanisms under which ACOT payments are made. These include:

1. The regulated ACOT terms in Schedule 6.4 of Part 6 of the Electricity Industry Participation Code (these apply to DG units specifically identified in lists published by the Authority); or
2. Bilaterally negotiated terms agreed between a DG owner and the host EDB; or
3. An internal transfer pricing arrangement where DG is owned by a host EDB or industrial consumer connected directly to the grid;[32] or
4. An agreement between a DG owner and EDB, which is associated with a Prudent Discount Agreement or Notional Embedding Agreement (in the case of notionally embedded generators) between Transpower and the relevant EDB.

In broad terms, the posited TPM change is expected to remove the incentives associated with avoidance of RCPD charges for DG in 1) and 3). Instead, we expect these DG to respond to spot prices.

In relation to DG in 2) and 4), the same broad observation applies, but the effect may be delayed or diluted by the terms of the relevant pre-existing contracts between DG owners and EDBs. A further complicating factor is that some DG which qualifies under 1) may have contractual entitlements under 2).

Given the various uncertainties, we adopt the conservative (i.e. worst case for reliability) assumption that ACOT payments related to RCPD charges will cease for *all embedded and notionally embedded DG* under the proposed TPM.

We also adopt the conservative assumption that DG owners receive no other ACOT-like payments to operate in peak periods once the RCPD charge is withdrawn. We note that ACOT-like payments

[32] Strictly speaking, if the legal entity which owns DG is the same as that paying transmission charges, no internal transfer pricing arrangement will apply. Instead, the entity will have a direct incentive to operate DG in a way that optimises its transmission charges.

could arise in the future if an EDB contracts with DG to reduce its exposure to future benefit-based charges, and/or if Transpower were to contract with DG to provide transmission alternative services as permitted under Part 4 of the Commerce Act.

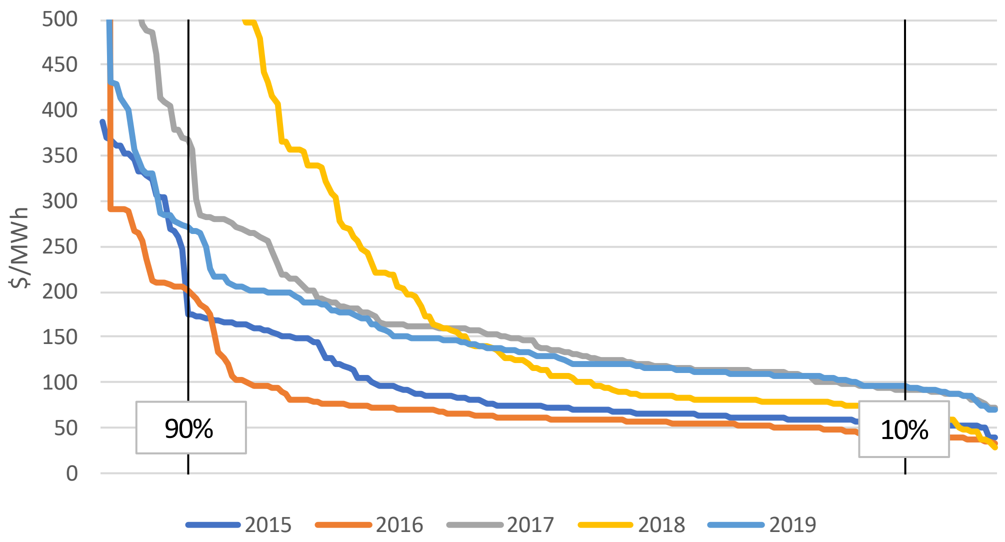
3.4 Wholesale market incentives

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 a 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. Figure 8 shows nodal prices at Haywards during the 200 trading periods with highest national demand each year since 2015. It shows that, with the exception of 2018, during which sustained high prices occurred, prices have generally been in the range $50-350/MWh during these periods.

Figure 8 - Observed nodal prices during highest national demand periods



The TPM changes would not directly affect the wholesale market. However, to the extent that the changes lower the system contribution of DG or DR during peak periods (all other factors being equal), this would be expected to place upward pressure on energy and reserve prices in such periods.[33] In effect, this would increase the wholesale market incentives for such providers to operate during times of system stress.

[33] See Section 6.

3.5 Hot water ripple control incentives

The effect of wholesale market signals on hot water ripple control providers is more complex to analyse. As noted earlier, ripple control of hot water heaters is thought to provide approximately 644 MW of effective DR resource. This resource can be utilised in a number of different ways including:

a) Switching load off to reduce transmission charges
b) Switching load off to reduce distribution investment requirements and hence costs
c) Leaving load on, but offering it into the reserves market as interruptible load (IL)
d) Switching load off to reduce energy charges.

Clearly, option c) 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'.

Removing the RCPD charge will alter the incentives for using hot water ripple control. The incentive to pursue option a) will cease under our assumption that there are no transmission charges associated with peak demand, but the other three main reasons will remain. The incentives for option d) will be increased if there is some uplift in energy prices in peak demand periods.

We have 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 in some cases. These include end-users, retailers, owners of ripple control receivers, and/or load aggregators.

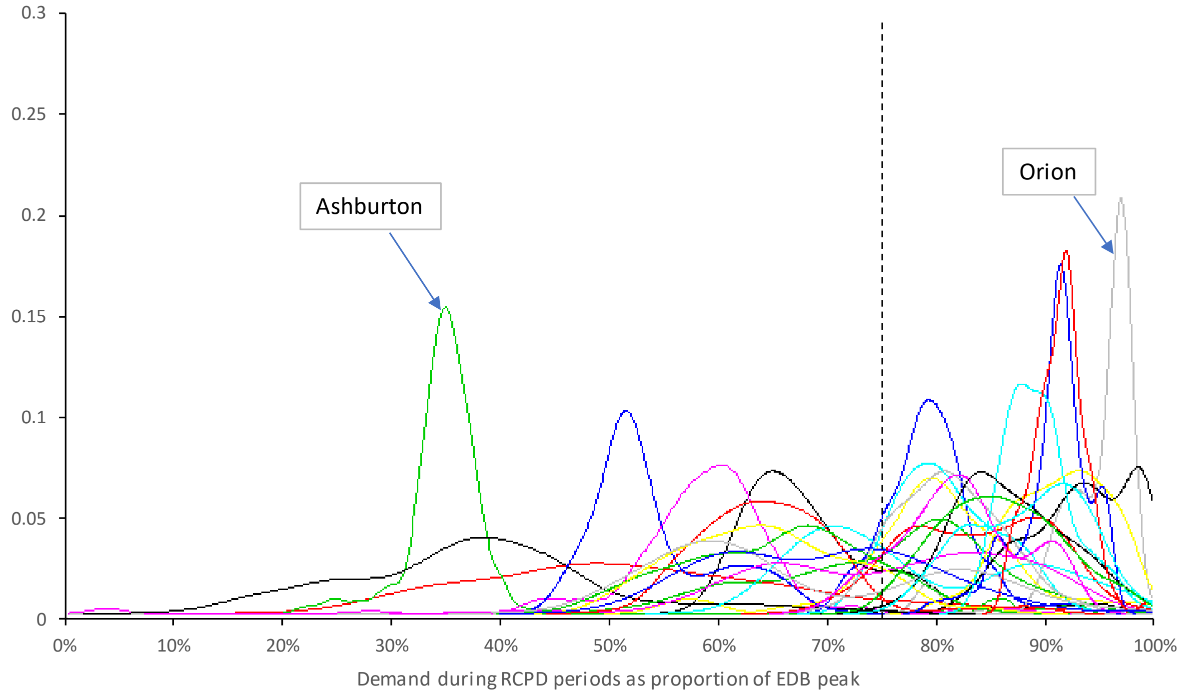
Given the multiple potential uses of ripple control, we consider a) to d) in more detail in the following sections.

3.5.1 Changes to incentives for hot water DR use – managing distribution network

EDBs can use ripple control to manage congestion on their own networks. To the extent that an EDB's load is correlated with RCPD periods, it is more likely that the EDB will continue to manage load to some extent during regional peak periods. We investigated the correlation between each EDB's own peak load with the load of their region. Figure 9 is a density plot[34] showing each EDB's relative load (i.e. their actual load relative to their anytime peak load) during RCPD periods. EDBs with load that is highly correlated with their region have a curve towards the right-hand side of the graph, and vice versa.

[34] A density plot is essentially a "smoothed" histogram.

Figure 9 - Relative EDB demand during 2019 RCPD periods



There is wide variation between networks. Some EDBs (e.g. Orion) are almost perfectly correlated with their regional demand, while others (e.g. Ashburton) are clearly not. These two curves can be interpreted as follows:

- during USI RCPD periods, demand for the Electricity Ashburton network was about 35% of anytime peak demand for Electricity Ashburton, and
- during USI RCPD periods, demand in the Orion network was between 90% and 100% of anytime peak demand for Orion.

To split EDBs into different groups, we have chosen a threshold of 75% (shown by the dotted line), meaning that EDBs with median RCPD demand greater than this are classified as "highly correlated", and vice versa. This threshold is somewhat arbitrary, and a higher or lower one could be used that would give slightly different results.[35]

Regions that are not highly correlated are assumed to have no incentive to manage their own load for distribution purposes during times of regional peak. About 95 MW of hot water ripple control falls into this category. Our base case assumes that these EDBs will not manage their water heating load during regional peak periods. This may be a conservative assumption as they may continue to manage load for reasons discussed in section 3.5.3.

On the other hand, we assume that regions that are highly correlated will continue to manage peak load during times of regional peak demand. However, this might not be the case if there is ample capacity on their network to handle local load. In our experience, EDBs will often have ample capacity in some parts of their network, while other parts will be near capacity limits. This is consistent with the nature of distribution investments which tend to be lumpy due to large efficiencies of scale. We are not aware how precisely EDBs can target different parts of their network with ripple control, or whether they have the desire to do so.

[35] Sensitivity case 2 assumes much less response from EDBs for local network management reasons. This effectively sets the threshold for "highly correlated" much higher.

Because of this, in our base case, we have assumed no change to EDBs with highly correlated peak load. While this may appear overly optimistic, sections 3.5.2 and 3.5.3 discuss additional reasons why we do not expect sudden changes in ripple control behaviour for the EDBs.

3.5.2 Changes to incentives for hot water DR use – offering into the reserve market

Many large EDBs in the North Island currently offer hot water load into the reserves market as interruptible load (IL) but periodically reduce their IL offers and use ripple control to reduce energy demand. This behaviour is believed to be intended to avoid transmission charges, which typically provide a much higher direct financial incentive[36] than the IL price signal.[37]

Most EDBs that participate in the IL market have demand which is "highly correlated" with the RCPD load for their region, so we assume in section 3.5.1 that they will continue to manage their load for distribution network purposes during peak periods if the RCPD charge is removed. However, if they have sufficient distribution network capacity that this is not the case, we expect their most likely behaviour would be to offer the associated demand into the reserves market as currently occurs in many non-RCPD periods.[38]

We estimate that about 170 MW of load could be offered as reserve during peak periods if it is not already being curtailed for distribution network management purposes. Based on past observations of changes to demand, and changes to fast instantaneous reserve (FIR) and sustained instantaneous reserve (SIR) offer quantities, we estimate that 170 MW of load would increase the amount of offered SIR during peak periods by about 140 MW. We estimate that it would increase the amount of FIR by about 60 MW.

Additional reserves are a form of capacity because they allow generation plant that would otherwise be required for spinning reserve to produce energy. The "co-optimization" interactions are complex, but we make the simplifying assumption that one MW of additional reserve frees up one MW of plant capacity to be used for generation instead of spinning reserve.

However, this interaction is limited by the following effects:

- Only a finite amount of spinning generation plant can be displaced. Clearly there can't be less than zero, but there may also be a limit above zero due to frequency stability concerns.
- Both FIR and SIR need to be satisfied, and while generation plant can (typically) provide both in equal amounts, that is not always the case for IL.

During peak periods about 150-200 MW of SIR is required to cover large thermal units. While there are other competing sources of IL, much of this would not be available at peak because the load will have already switched off to avoid high spot prices. We expect that there would often be sufficient spinning reserve that 140 MW of hot water ripple control SIR would be scheduled and displace spinning reserve in the SIR market.

However, this would not result in additional generation capacity being freed up unless it also reduced the requirement for spinning reserve in the FIR market. For most peak periods, more SIR is required than FIR because they are scheduled on different bases: SIR must cover the size of the contingent risk, while sufficient FIR is required to limit frequency drop within the first few seconds

[36] One factor that complicates this assessment is that EDBs subject to price-quality control have no direct financial incentive to minimise transmission charges since these are treated as a pass-through cost for their revenue cap. Conversely, revenues from provision of IL services appear to fall outside (at least in part) the regulated revenue cap. Despite this, such EDBs appear to actively manage their peak demand in RCPD periods (and reduce their IL offer volumes). This may in part be to minimise distribution costs.

[37] See para 4.13, "2014 Winter Grid Emergencies" paper https://www.ea.govt.nz/dmsdocument/18801

[38] Because EDBs receive a financial benefit from offering IL

after a contingent event.[39] During peak periods, system inertia is higher meaning that less FIR is required to limit frequency drop. During the top 200 peak periods in 2019, 55-60 MW more SIR was required than FIR on average. Although hot water IL provides less FIR on average, less FIR than SIR is required at times of peak, so these effects offset each other somewhat.

We note that the above discussion ignores the effect of transmission losses. Each MW of controllable load that is left on and offered into the reserve market will free up less than one MW of generation capacity because it will increase transmission losses.

In summary, we don't expect all potential EDBs to offer all their possible load as IL, because our base assumption is that most will be managing load to control their own distribution peak. However, if this assumption is not accurate, the impact of the extra load will be minimal if they offer a modest amount of IL into the reserves market instead.

This interaction will not hold if sufficient quantities of load is left on and offered into the reserves market such that it does not displace spinning reserve. We do not believe such an outcome is likely, and it is effectively captured in sensitivity case 1 – increased load from reduced operation of DR.

3.5.3 Changes to incentives for hot water DR use – energy prices

The presence of multiple parties with differing rights to interrupt water heater load creates some uncertainty over how this resource would respond to a change toward reliance on nodal price incentives. In particular, if nodal energy price signals were higher during regional peak periods following adoption of the TPM changes, it is unclear how effectively DR from ripple control would be able to respond, at least initially. For example, one EDB has previously indicated that it may need to consult with retailers operating on its network before making any changes to its practices. 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 the consumers in areas served by an EDB.

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. minimal need to manage distribution demand with load control),[40] 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 EDBs subject to price-control control do undertake significant peak demand management during RCPD periods. This 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.

[39] This is a simplification. Free reserves and covering extended contingency events complicate this.
[40] 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.

Given this uncertainty, we do not assume that EDBs will apply ripple control solely to avoid high energy prices. However, this is a conservative approach and it is possible that EDBs will control to avoid high prices, especially given the expected uplift in spot prices.

We also believe that most EDBs are likely to seek to phase in any significant change for mass-market customers over several years for a number of reasons. For example, a sudden cessation of load control (and presumed withdrawal of controlled tariff rates) may alter the incidence of charges among customer groups, leading to so-called 'rate shock'.

In addition, 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. This suggests that overnight and complete removal of controlled/uncontrolled load tariff differentials would be unlikely.

We consider these effects further evidence that our assumption that EDBs with highly correlated load will continue use hot water ripple control to manage their distribution network is reasonable.

3.6 EDBs with highly Overall predicted hot water ripple control outcome

Figure 10 shows how the total change in hot water ripple control is estimated taking account of the different effects noted above.

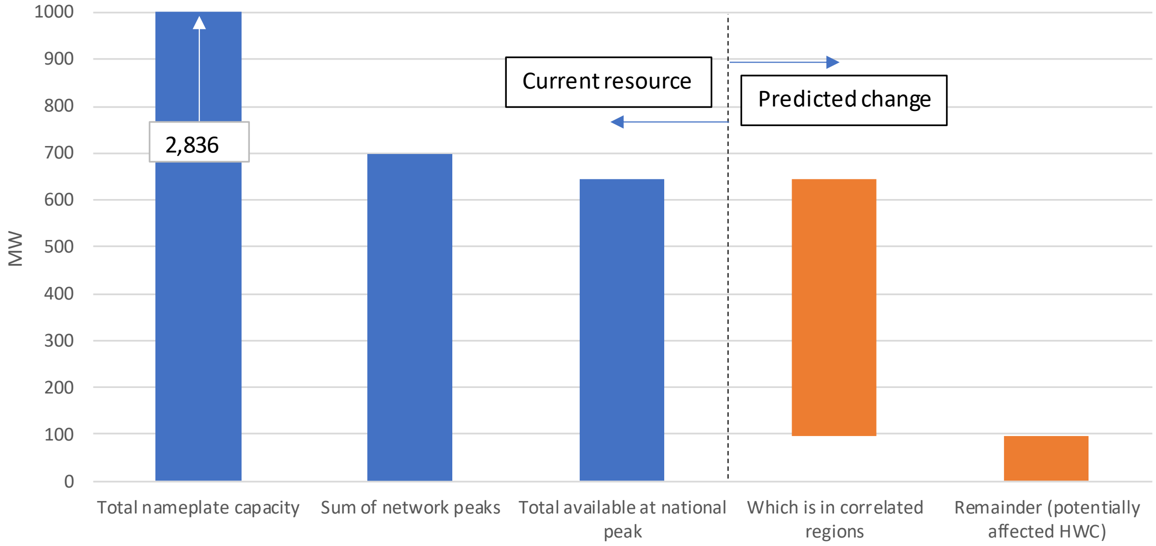
The total nameplate capacity of ripple-controlled water heaters is very large, but only a portion of cylinders are switched on at any one time ("sum of network peaks"). Furthermore, the total switched on during national peak periods is slightly lower still, because network peaks don't necessarily line up with national peak demand.

Of this total available resource, we estimate that 549 MW is in regions that have their distribution peak highly correlated with national peak, and so will continue to be controlled, primarily for distribution purposes. There is about 95 MW of resource in regions that are not "highly correlated".[41]

In our base case, we assume that all load in regions that are not "highly correlated" will no longer be controlled during peak periods.

[41] About 43 MW of this extra load is in the South Island. This extra load would result in lower northwards flow on the HVDC and lower overall losses leading to an increase in the estimated WCM. We have ignored this effect as it is relatively minor.

Figure 10 - HWC quantity assumptions



3.6.1 Use of ripple control when requested by System Operator

Even if EDBs do not elect to control hot water load during system peaks, the System Operator may request they do so if needed to maintain system security. Currently this happens as needed through the use of Customer Advice Notices in the lead-up to an anticipated supply shortfall. With the introduction of real time pricing (RTP), [42] this process will be more formalized, but will operate in a similar manner in practice. This means that during the most severe events, we expect there will be little change to whether hot water ripple control is utilized.

3.7 Introduction of real-time pricing in 2022 expected to increase incentives for DG and DR operation

The comments in the sections above regarding spot price incentives reflect the current Code and market arrangements. In late 2022, a significant change to the electricity spot market is scheduled to occur with the introduction of RTP.

We expect RTP to significantly strengthen the incentives on DG and DR to operate in peak demand periods, where it is efficient for these resources to do so. The key reasons for this view are:

- RTP is designed to provide clearer and more actionable price signals to DR providers and generators. At present, an indicative spot price signal is provided in real time and this can be substantially revised before settlement prices are finalised (at least two days later). In contrast, RTP will publish settlement-grade prices in real time.[43] This should make it easier for parties to react to changing system conditions, such as in peak demand periods. This should be particularly useful to smaller parties (such as smaller scale DR and DG owners) who are less likely to have the resources to fully analyse the current indicative prices for decision-making purposes.
- RTP will provide clearer price signals in periods when offered DR and supply is insufficient to meet forecast demand. At present, an administered price signal can apply if there is an island-wide or national shortage of offered resources to meet demand. The administered

[42] See www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/development/decision-to-implement-rtp/

[43] Half-hourly settlement prices will be a time-weighted average of dispatch prices published in real time for each node on the grid.

signal is intended to provide strong incentives for the provision of additional resources while avoiding price over-shooting. However, the mechanism is relatively blunt, is uncertain in its effect (it has never been triggered) and does not apply if shortages occur at a regional or sub-regional level. RTP's equivalent mechanism will address shortages affecting any geographical area from a single node to the whole grid. It also includes a pre-defined and graduated pricing scale for shortages which should provide more certainty for industry participants.

Overall, relative to the current position, we expect RTP to sharpen the spot price-based incentives on DR and DG to operate if it is efficient for them to do so in peak demand periods.

3.8 Scenario descriptions

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.

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.

Table 4 - Scenario descriptions

Case	DG behaviour and rationale	DR behaviour and rationale
Status quo	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
Base case	Nodal prices in RCPD periods are assumed to (at least) reach levels seen in the past (from 50 to 350 $/MWh for most periods). Most DG has a short run marginal cost (SRMC) significantly below this level, and it is therefore profitable to operate based on nodal prices. The exception is diesel-fired DG plant - which typically has a higher SRMC.[44] 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 about 128 MW of diesel-fired capacity in total.[45] We also assume that there will be some reduction from controllable, non-offering hydro plant. Although we assume that the nodal price will always exceed their SRMC, this type of plant may find it more difficult to respond to a nodal price than an RCPD signal. RCPD is	Grid-connected industrial users that have been observed to respond to RCPD signals or nodal prices in excess of 500 $/MWh are assumed to cease such DR, on the basis that any nodal price increase from tighter supply / demand balance may be insufficient to compensate for the removal of RCPD signals. There is around 44 MW of capacity estimated to be in this category, as discussed in section 2.7. Likewise, some commercial and industrial DR that operates based solely on the RCPD signal is assumed to cease responding. In the absence of specific data for this category, it is assumed to be the same volume as for grid-connected industrial load (i.e. 44 MW). For the reasons discussed in section 2.7, this may be an over-estimate. Ripple control of hot water is assumed to be reduced. There is a reduction of 95 MW from reduced response to RCPD as discussed in section 3.5. The total assumed reduction from DR is 183 MW

[44] 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.

[45] The estimate based on market data is 128 MW. 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. Similarly, some diesel generation could be de-rated further because it is in the South Island and so it would provide less than 1:1 extra capacity in the North Island due to losses on the HVDC and AC network.

Case	DG behaviour and rationale	DR behaviour and rationale
	based on demand, while prices are determined by various inputs, including demand, transmission availability, and supply offers. Accordingly, prices are significantly harder to forecast and so we assume that some small operators will not undertake the effort to do so. To account for this, we have de-rated this group's contribution by 50%, or 21 MW Other DG plant is assumed to operate as per the status quo, either because it is inflexible, or because owners are sufficiently incentivized to continue to make plant available because nodal prices (on average) are likely to exceed the plant SRMC. The total assumed reduction from DG is 148 MW	
Sensitivity case 1	As per Base case	As per the base case – but a larger reduction in ripple control and large user response is assumed. For the purposes of sensitivity testing, the case assumes all that, in addition to the base case reduction in DR, EDBs in "highly-correlated" regions have a 50% reduction in ripple control contribution. A reduction of this quantity could arise from under-estimation of the incentives for and operational practices by EDBs. We also assume that spot prices will not rise sufficiently to encourage demand response from large users. The combined effect is to tighten capacity margins by 327 MW relative to the base case.

Case	DG behaviour and rationale	DR behaviour and rationale
Sensitivity case 2	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: • Higher avoided cost of distribution payments • Higher payments from Transpower for transmission alternatives, and/or • Other revenues sources. 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). This is equivalent to an additional 234 MW of lost generation capacity in peak periods[46], and the total assumed reduction from DG is 382 MW. Other DG plant is unlikely to be able to restrict generation at short notice, and is assumed to operate as per the status quo.	As per base case.

[46] Deratings from the ASA analysis have also been applied to the name plate capacity wind plant.

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)[47]			
	DG	DR	Total
Base case	148	183	332
Sensitivity 1	148	510	659
Sensitivity 2	382	183	566

3.9 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.[48]
- 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, our analysis has not considered possible actions by the System Operator in the lead up to a forecast generation shortage.[49] 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:

- 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. The best indicator for these periods

[47] Estimates are rounded to two significant figures in table.
[48] See page 16 of the report; 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
[49] The optimal WCM margin does not include provisions for the System Operator calling for response.

is nodal prices, so 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 withdraw 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, or if EDBs operate ripple control to avoid high nodal price periods).

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 to the nodal price incentive for exercising ripple control of water heating load.

4 Capacity margins for 2021

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

4.1 Winter Capacity Margin 2021 - Base case

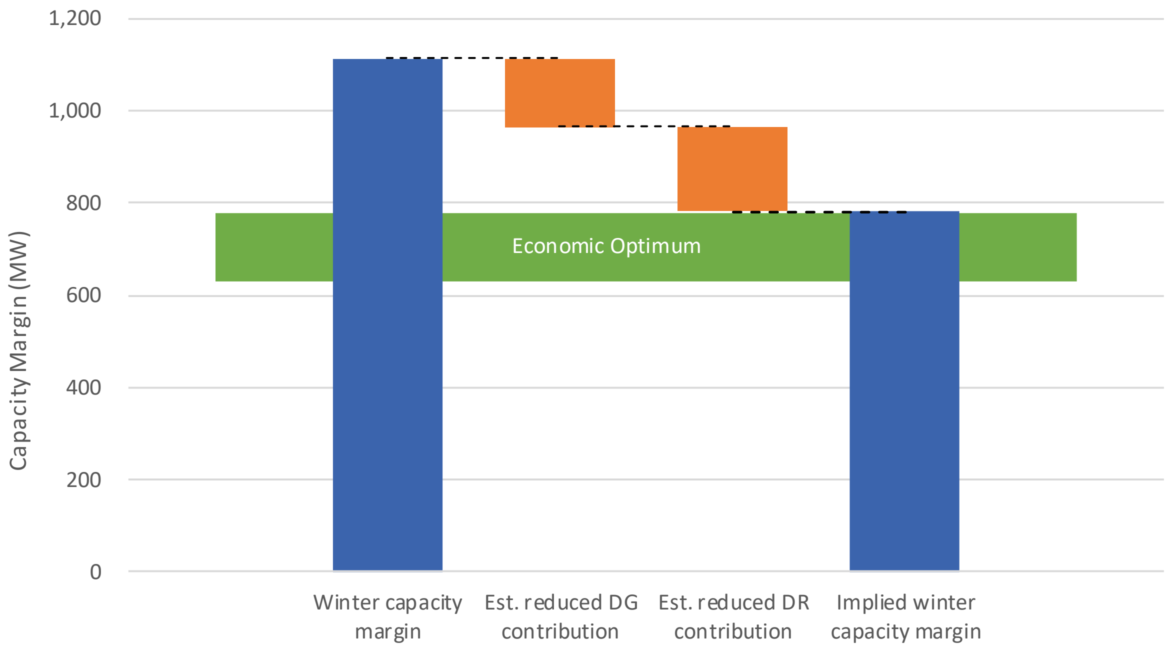
The left hand column of Figure 11 shows Transpower's projected North Island Winter Capacity Margin for 2021, based on existing and committed generation plant.

The assessed economic optimum range of the capacity margin is highlighted in green. This is the amount of capacity that is expected to minimise the total costs to society of generation 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 committed plant (blue bar) is 1,114 MW, as compared to an economic optimum range of 630-780 MW (green band). We note that the WCM does not include any additional non-committed new generation and any such generation would increase the estimated WCM for 2021.[50]

Under the base case, some reduction in DG and DR operation at peak is expected, and this is shown by the orange bars respectively. The net impact reduces the projected WCM to around 782 MW, which is at the upper end of the economic optimum range.

Figure 11- Base case- Winter Capacity Margin impact



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 additional reduction in DR contribution from this

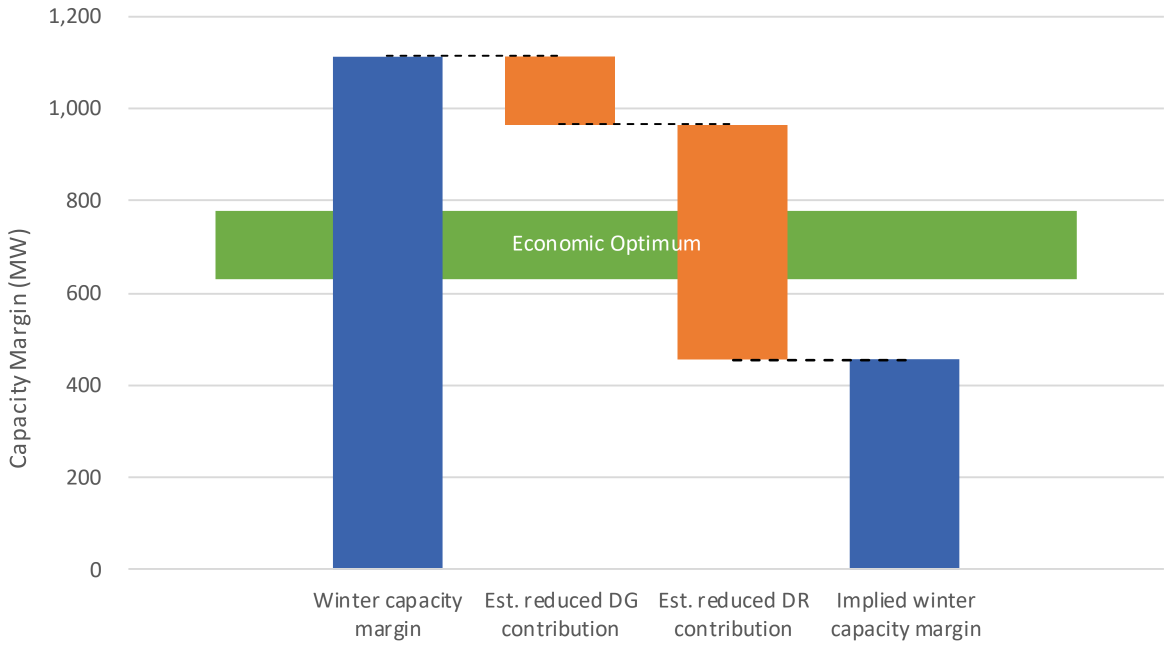
50 For example, we believe the 2021 WCM figure does not include Turitea or Waverley windfarms that were committed after the ASA was finalised, and which will provide about 200 MW of new wind generation. At a 25% derating, this would increase the WCM for 2021 by about 50 MW.

source, 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.[51] 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 2021, 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 659 MW. As shown by Figure 12, the resulting 2021 winter capacity margin based on existing and committed plant would be around 455 MW, which is well below the assessed economic optimum range.

Figure 12 - Sensitivity case 1 - Winter Capacity Margin



4.3 Winter Capacity Margin 2019 - Sensitivity case 2

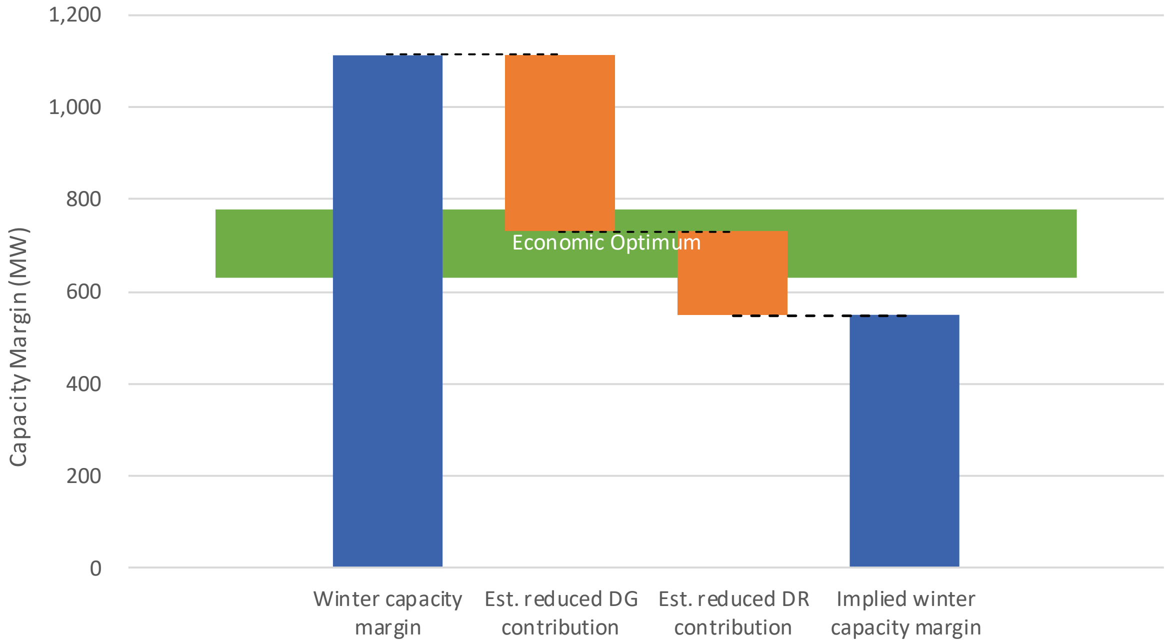
Although we expect the capacity contribution from most DG to be unchanged, we have considered a sensitivity case where a sizeable amount of non-diesel DG restricts its generation levels in tight system periods (foregoing immediate spot revenues), in the belief this will yield future net benefits, such 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 382 MW reduction in the firm capacity contribution from DG.

[51] The exception is ripple control which can participate in the reserves market However, this is a subset of ripple control DR.

In aggregate, these changes would reduce the projected winter capacity margin for 2019 by around 566 MW. As shown by Figure 13, the resulting 2021 winter capacity margin based on existing and committed plant would be around 548 MW. This is below the economic optimum range.

Figure 13 - Sensitivity case 2 winter capacity margin impact



5 Review of Transpower's "The role of peak pricing for transmission"

Transpower released "The role of peak pricing for transmission" in November 2018.[52] This paper outlined Transpower's views on the merits of a peak-based transmission price signal in addition to nodal prices.

Some of the analysis in Transpower's report comments on Concept's 2016 report on the effect of TPM changes on the WCM,[53] which this report updates. Where relevant, we address Transpower's feedback on the methodology adopted by Concept in 2016.

Transpower's paper also commented on the potential regional level impacts of removing the peak-based charge in a new TPM.

We comment on each of these topics below.

5.1 Response to Transpower's comment on Concept's analysis

Transpower's paper suggested that Concept's 2016 report was "optimistic" and stated that "it would not be prudent to rely on that analysis". We are confused by this assessment, given that the overall impacts on capacity margins in Concept's 2016 report appear to be similar to the values estimated by Transpower in 2018 (as set out in Attachment D to "The role of peak pricing for transmission").

We agree that Concept draws a different conclusion from Transpower, but suggest that this is due to a difference in assessment criteria, rather than any discrepancy in underlying expectations of market response to a change in TPM.

A key assumption in both pieces of analysis is how DG and DR will behave in the absence of an RCPD signal. Table 6 compares the assumptions from:

a) Scenario 3 in Transpower's Attachment D,
b) The base case scenario in Concept's 2016 report, and
c) The base case scenario in Concept's 2020 report.

Table 6 - Assumption regarding DR and DG changes under alternative TPM

	Transpower	Concept 2016	Concept 2020
DG	0[54]	117	148
Large user DR	0[55]	100	88
EDB DR	296	50	95
Total	296	267	332

Table 6 shows that the assumptions about the individual impacts on DR and DG appear to differ materially between Transpower and Concept. Transpower has assumed a larger decrease in EDBs'

[52] www.transpower.co.nz/sites/default/files/plain-page/attachments/Transpower_The_Role_of_Peak_Pricing_for_Transmission_2Nov2018.pdf
[53] Winter capacity margin – potential effect of possible changes to transmission pricing and distributed generation pricing principles – December 2016
[54] Transpower has used SPD to perform its analysis. SPD dispatches generators according to their offers, so there may be more dispatched response from offered distributed generation. However, the total amount of generation offered will not change.
[55] Transpower did not anticipate changes to this category of demand and state that nodes which have large, single-point load "can be expected to respond to high energy prices".

hot water load control, but appears to have assumed no change to major users' behaviour, nor to the operation of distributed generation.

It appears that Transpower's arrived at the 296 MW value by assuming that 70% of reported[56] hot water ripple control was operated during RCPD periods, and that all such response would cease. This is a different basis to Concept's approach, which assumes some hot water load control will continue during peak periods for other purposes such as distribution network management. Concept's analysis also considers interactions with the instantaneous reserve market.

Transpower's approach is more similar to Concept's sensitivity case 1 in our 2020 report that assumes a much greater reduction in hot water load control. In this sensitivity 1 case, we assume there will be 370 MW of extra hot water load during peak periods. This is more than Transpower's assumption of 296 MW, suggesting that Concept's sensitivity case models a sufficiently conservative situation.

Transpower appears to have assumed no change to DG operation. Transpower notes that this is a "conservative approach",[57] but that they "focussed on EDB's load control because EDBs have no commercial incentive to respond to energy prices." We mostly agree with the implication in this statement that non-EDB parties will respond to nodal prices.[58] However, we have elected to make the conservative assumption that diesel generation and some small hydro plant will not operate because the "commercial incentive" from nodal prices alone may not be sufficient.

Transpower does not appear to have explicitly considered changes in behaviour of larger users.

Although there are differences in assumed DR and DG response between Transpower and Concept, the combined impacts for DR and DG appear quite similar. Concept's 2016 report assumed about 30 MW less impact on WCM than Transpower's analysis, while Concept's 2020 report assumes about 36 MW more impact than Transpower's analysis.

Overall, it appears Concept and Transpower expect similar *aggregate* impacts on capacity margins from removal of peak-based transmission charges, but for different underlying reasons.

Despite the apparent similarity of aggregate impacts, Transpower states that Concept's 2016 report had:

i. an unduly optimistic base case; and
ii. overly optimistic worst case scenarios.

We are somewhat confused by this assessment, especially as our 2016 sensitivity case 1 assumed higher EDB demand response than Transpower's assessment.[59]

It is possible that the source of difference is the interpretation of the economically optimal winter capacity margin (WCM). It is useful to reiterate what this margin represents. It is the level at which there is no net incremental benefit from making supply investments to further reduce unserved demand. By definition, unless building new generation plant is free, the optimal WCM will always involve some expected level of forced load shedding that is above zero (albeit small).

Concept's 2016 report concluded that it was likely the removal of RCPD would reduce the WCM to within the economically optimal range. Transpower's Attachment D did not use an economic

[56] Self reported by EDBs in response to a 2016 survey. "Many (but not all)" EDBs reported the quantity of hot water ripple control on their network.
[57] Transpower uses the term "conservative" to mean the opposite of Concept. By "conservative", Transpower means that the assumption will lead to greater security margins. When Concept uses this term we mean that the assumption will lead to smaller security margins, or in other words, our conservative modelling is more likely to over-estimate the chance of capacity shortage.
[58] Although we disagree with the simplification that EDBs will not respond to nodal prices. See Section 3.5.3.
[59] Concept assumed 367 MW in 2016 compared with Transpower's 296 MW.

capacity standard as its reference point. Rather it stated that during the highest ever observed historical demand, there would have been unserved energy based on the assumptions adopted in Attachment D. Thus, Concept's analysis adopted an economic standard as its reference point, whereas Transpower's analysis assessed effects relative to an implicit reference point of avoiding all involuntary load shedding.

5.2 Regional security risks

Transpower's report also sought to quantify the extra costs that might arise from additional transmission infrastructure needed to meet higher regional demand peaks. Transpower presented two regional case studies in Attachment C of its paper:

1. Upper South Island
2. Upper North Island

Concept did not consider any regional effects in our 2016 report, as we were not in a position to perform the power flow analysis required. Neither can we comprehensively review Transpower's analysis for the same reason in this report. Instead, we offer some high level comments on the key assumptions in Transpower's analysis using other sources, including our own estimates and other publications produced by Transpower.

5.2.1 Additional costs arising from accelerated transmission investment

For both regional case studies, Transpower assumes that an increase in demand will bring forward the required date for transmission upgrades. Transpower's additional costs are calculated from the estimated cost of the upgrade, and the change to when the upgrade is required. If an upgrade is required sooner, then on a cashflow adjusted basis, the upgrade is more expensive given the time value of money.

This approach to assessing regional effects is reasonable in principle. However, we note the conclusions are sensitive to the input assumptions, and the analysis does not consider some factors relevant to forming a view on overall effects. We comment further on each matter below.

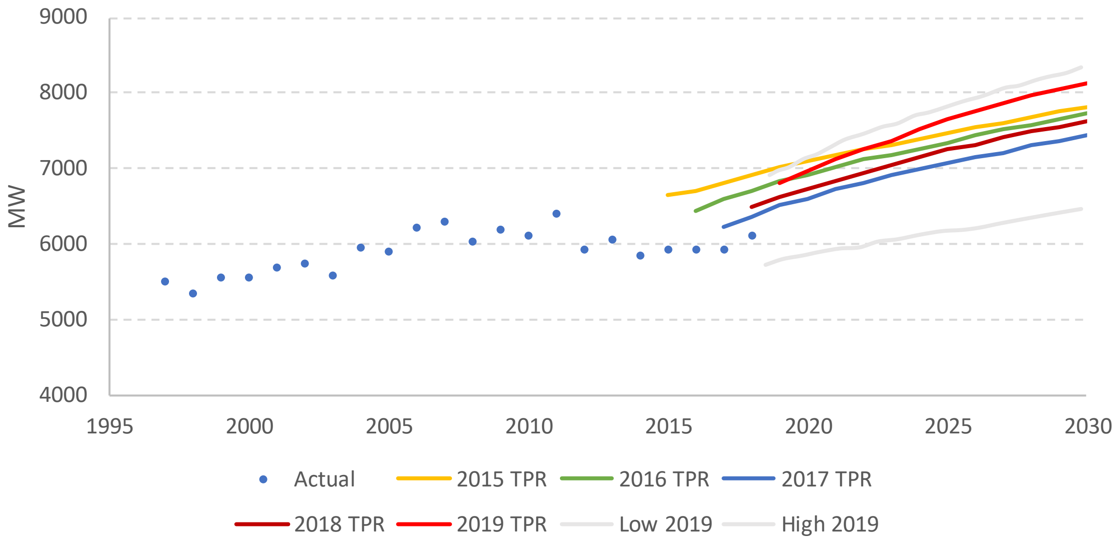
5.2.2 Demand growth assumptions

The key assumptions which drive Transpower's estimates of project timing are the magnitude of demand growth and the quantity of increased demand from removing RCPD.

Figure 14 shows forecast national demand growth from Transpower's 2018 Transmission Planning Report (TPR 2018). This forecast is for national demand, rather than Upper North or South Island demand[60], but our commentary relates to general characteristics of forecasts and is not dependent on the exact forecast in question.

[60] Neither are present in the TPR 2018. A forecast is shown for each grid exit point, but the total forecast for a region is not simply the sum of the individual grid exit points because the regional peak may not necessarily coincide for each exit point.

Figure 14 - Transpower's forecast of peak demand[61]



Transpower's demand forecasts are for "prudent peaks". As such, they are not the expected demand each year, and are difficult to compare from year to year. However, there is clearly significant revision undertaken with each new forecast. The expected growth over time has increased in the 2019 forecast, while the expected "starting point" jumped up in 2018 and 2019.[62]

Transpower states that they have substantially revised their demand forecasting approach in the TPR 2019 to take account of emerging technologies and the possible electrification of some parts of the economy. These changes led to "considerable uncertainty regarding future demand growth" in the medium[63] to long term. This uncertainty reflects the difficulty in forecasting peak demand and should be kept in mind when reviewing the impact of small changes to demand forecasts for many years in the future.

Forecast demand is very important for the conclusions in Transpower's Attachment C. If peak demand were not to increase (as has been observed nationally for the previous 14 years) or were to be delayed by a few years (perhaps more likely), there might be no need for additional investment, or it might be deferred.

5.2.3 RCPD response assumptions

The other key assumption in Transpower's timing analysis is the quantity of increased demand if RCPD were removed. We have distilled estimates of DR and DG impacts for the Upper South Island and Upper North Island from our national estimates. Table 7 shows our estimated quantity of DR and DG split by resource type:

Table 7 - Estimated regional DG and DR change

	EDB DR	large user DR	Hydro DG[64]	Diesel DG	**Total (Concept base case)**	**Transpower Attachment C (7% increase)**
Upper South Island	18	0	5	69	**93**	**78**

[61] Reproduced from TPR 2019 source due to poor quality of original image.
[62] As these are prudent peak forecasts, we would normally expect the forecast for a particular year to drop slightly with each new forecast.
[63] We understand that medium term includes RCP4 (2025-2029).
[64] DG quantities are based on the "UNI" and "USI" regions as defined on EMI. This may not correspond exactly to the regions considered for transmission investment.

Upper North Island	24	48	1	22	**95**	**181**
Upper North Island (Sensitivity 1 DR assumptions)	132	68	1	22	**223**	**181**

Concept's base case estimate of overall regional DG and DR for the Upper South Island is comparable to Transpower's.

For the Upper North Island, Concept's sensitivity case 1 is more similar to Transpower's. This is because most of the demand for EDBs in the Upper North Island is highly correlated with regional demand, meaning that in our base case we have assumed it will respond for distribution network purposes.

Although there are similarities, Concept's and Transpower's numbers are calculated using very different methods. Concept has included possible response from large users and distributed generators. Transpower does not explicitly consider these sources of DG and DR.

Overall, we believe Transpower's assumptions are not unreasonable, but note the high degree of uncertainty present for forecasts of both peak demand and demand response.

5.2.4 Updated information from Transpower

Transpower's forecasting was based on the TPR 2017.[65] Concept has reviewed more recent Transpower publications, including the TPR 2018 and TPR 2019, to determine if more up-to-date information is available that might affect the estimates in Attachment C.

Upper South Island

Canterbury demand[66] projections in 2018 TPR were 4-6% higher than the 2017 TPR. Canterbury demand projections in the TPR 2019 were then revised back to be similar to the 2017 TPR. Thus, the recent revisions to underlying projected demand (inter-year changes of 4%-6%) appear similar in magnitude to Transpower's estimates of the effect of the TPM on peak demand (3%-7%). This reinforces the point in section 5.2.2 that the uncertainty in Transpower's estimated costs is understated given the background 'noise' from underlying demand uncertainty.

Putting that issue to one side and focussing on the latest TPR, the transmission upgrade required for the Upper South Island case study described in Attachment C is based on a 2013 report.[67] Transpower states in the TPR 2019: "We are currently reviewing the need date for the Orari and Rangitata switching stations build phase due to changes in forecast demand". This suggests that the need date may change with more recent forecasts – but it is unclear how this would affect the cost estimates in Attachment C.

Upper North Island

Auckland demand in the TPR 2019 is about 1.7% higher for 2020, and 4.5% higher for 2025 than the TPR 2017, suggesting that the demand assumptions in Attachment C may increase if they were updated using Transpower's latest forecasts.

[65] "The scaling was performed on the winter island peak prudent forecast of peak demand for TPR 2017."
[66] This was calculated by summing the prudent peak forecast for grid exit points in Canterbury. The Canterbury data was used because it is easier to compare this across TPRs than for the Upper South Island region as a whole. In any case, Canterbury accounts for most of the demand in the Upper South Island region. The sum of prudent peak demand does not provide an accurate measure of regional coincident peak demand, but has only been used to estimate changes between different TPRs and should be valid for that purpose.
[67] Orari Switching Station – Solution Study Report (March 2013) by AECOM.

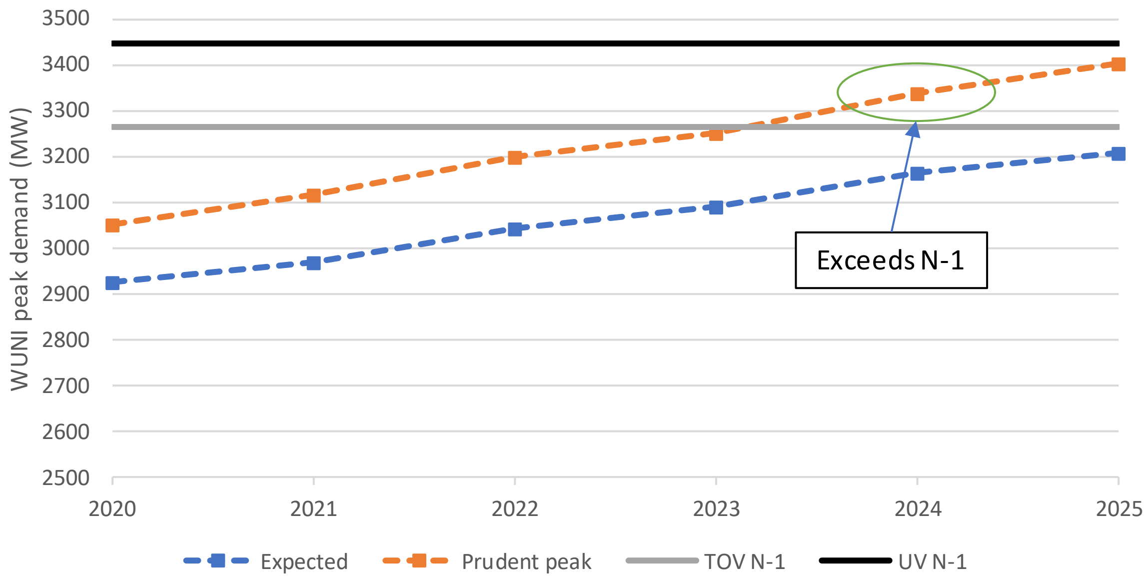
The Waikato and Upper North Island (WUNI) project is a transmission investment to support voltage in those regions to address demand growth and the possible exit of thermal generation in the region.

The timeline for the project is currently set by the possible exit of the remaining two Huntly Rankine units, which may occur in 2022. If these units exit, then the first stage will need to be in place for winter 2023. However, even if these units remain, projected demand growth in the region may lead to voltage issues during winter 2024.

The retirement of the Huntly units would result in a loss of about 500 MW of generation in the region and would represent a significant change. If the units retire as proposed, there will be need for transmission investment irrespective of whether the TPM changes occur.

As such, we consider the impacts of the TPM changes in the period before possible retirement. We also consider later years in a scenario in which the Huntly units remain.

Figure 15[68] - Transpower's WUNI peak forecasts[69] (no further Huntly retirement scenario)



Under Transpower's peak demand growth forecasts, the prudent peak will exceed the over-voltage N-1 limit in 2024.[70]

[68] "TOV" stands for transient over-voltage. "UV" for under voltage.
[69] Demand forecasts do not consider how very high spot prices may supress demand at peak if there is insufficient transmission capacity.
[70] Although it may look like the limit is exceeded during 2023, the data is not continuous. The graph should be assessed at each point, representing a winter peak.

Figure 16 - Transpower's WUNI peak forecasts (no further Huntly retirement and Transpower's extra HWC load assumptions)

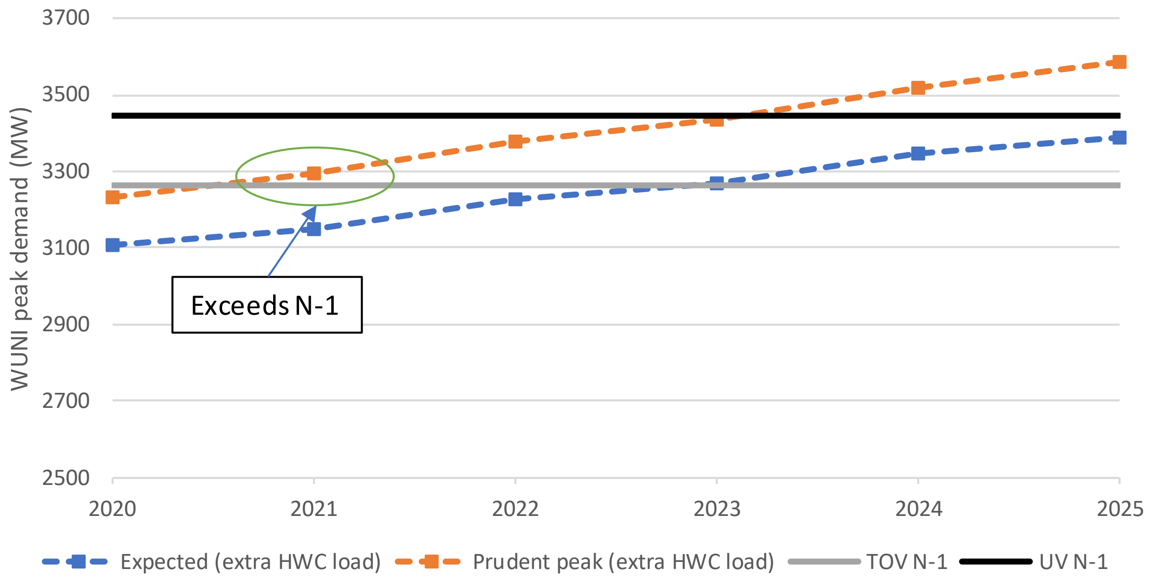
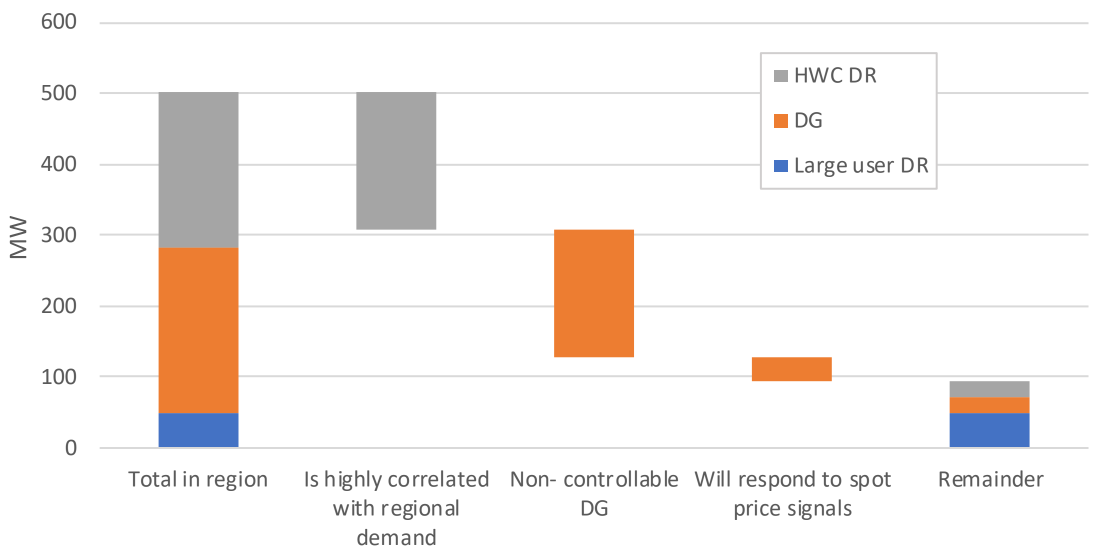


Figure 16 replicates Figure 15, but adds extra demand of 181 MW to reflect Transpower's forecasts to account for the changes to the TPM. The revised prudent peak will exceed the over-voltage N-1 limit in 2021. The under-voltage N-1 limit will also be exceeded in 2024.

Concept's base case assumes a smaller increase in demand of 95 MW. The derivation of the 95 MW is summarised in Figure 17.

Figure 17 - Sources of DR and DG in WUNI region



Although there is potentially about 500 MW of DR and DG in the region, the majority of this is hot water ripple control in EDBs that are highly correlated with regional demand, and DG that is unlikely to change its operation in response to withdrawing the RCPD signal.[71] Note that the ability to offer IL into the reserve market and free up additional generation is not considered for regional situations, because IL is dispatched on an island basis.

[71] For example, geothermal, PV and cogeneration.

The potentially affected DR and DG consists of 48 MW of large user DR, 23 MW of hot water ripple control and 22 MW of diesel DG.

With Concept's assumptions the adjusted prudent peak forecast demand exceeds the "Transient Over-Voltage N-1" risk by 28 MW in 2022.

Transpower's estimated demand increase is significantly higher at 181 MW. Under this assumption, the need for transmission investment would be brought forward to 2021 (i.e. next winter).

Table 8 summarizes the different possible scenarios.

Table 8 - Year when transmission investment required

	If Huntly retires	If Huntly stays
No change to TPM	2023	2024
Concept estimate (82 MW increase)	2022	2022
Transpower estimate (181 MW increase)	2021	2021

If Transpower's assumptions are correct, then it's likely that a physical solution would be difficult to implement under such a tight time schedule. Although Concept does not believe that Transpower's assumptions are likely, we acknowledge there is uncertainty around ripple control management.[72]

Accordingly, we believe there is some merit in a transitional measure for the WUNI region.

5.2.5 Other regional situations

We recognize that Transpower's regional analysis only considered two major regional situations and not all possible regional situations. Transpower publishes a more comprehensive list of such situations.[73] Assessing these situations is beyond the scope of this report.

5.3 Benefits and costs

Transpower's Attachment C outlines some possible costs due to transmission investment that could be brought forward due to increased peak demand under a different TPM. However, this is only a small part of the complete economic assessment that should inform whether a change is economically desirable or not:

To correctly assess the effect of the proposed change, Transpower's analysis would need to consider the potential benefits that such grid investment could confer. It would also need to consider any *suppressing* effects that the proposed TPM would have on demand, which could defer investment.

For example, we observe that much of the South Island is *summer* peaking, and this drives much of the projected work in the TPR 2018. RCPD may not be a particularly good charge to efficiently defer this type of investment because:

- The RCPD charge is based on only two large regions in the South Island. Most potential investment projects in the Upper South Island in the TPR[74] are to address localized congestion situations. Local demand may not be well correlated to regional coincident peak demand.
- Lines ratings are often lower in summer,[75] and RCPD does not take account of this.

[72] Our Sensitivity 1 scenario adopts more conservative assumptions about ripple control, and has similar assumptions about demand increases to Transpower's.
[73] https://www.transpower.co.nz/keeping-you-connected/industry/transmission-alternatives
[74] By number.
[75] For example, 30/37 MVA summer/winter ratings on Coleridge-Hororata circuits. Winter capacity is more than 20% higher than summer.

A proper assessment of the impact of removing the RCPD charge would not just consider one element of the total benefit-cost picture (i.e. only investments brought forward, and only costs and not benefits).

6 Transitional measures

We believe the largest risk to system security is during the transitional period soon after the assumed withdrawal of the RCPD signal. The removal of the RCPD signal would be a sizeable step change. While we believe participants would adjust to that change, we don't know with certainty how swiftly this adjustment would occur. The uncertainty is greatest for water heating ripple control, given the multiple actors and incentives that apply.

Additionally, since the RCPD charge for each year is set by behaviour in the previous one, the RCPD *signal* ceases in the year prior to the RCPD *charge* ending. The incentives change in the final year of the existing TPM, so we believe this is the year with the largest potential for something unexpected to occur.

Having said that, our national base case results indicate that changing from the RCPD signal to the new TPM should not reduce security below economically acceptable levels. We project that contributions from DR and DG will reduce slightly, but that the winter capacity margin will remain above the economic optimum. Taken at face value, this result suggests that there is no need for a transitional measure, such as a transitional peak charge, to mitigate possible risks.

Nevertheless, there are sound reasons to consider the merits of a transitional peak charge, or some other form of risk mitigation, during a transition phase:

1. While we do not consider it as likely as our base case, we acknowledge the potential for higher than expected reduction in DR and/or DG. Our sensitivity cases 1 and 2 both result in a lower than optimal WCM, meaning there would be more unserved energy than is economically optimal.
2. The economically optimal WCM range is used as the reference point to assess national level effects. Although we have no reason to believe that the optimal range is incorrect, the foundational analysis was undertaken some years ago and has not been updated to our knowledge.
3. Transpower's regional scenarios have identified a significant increase in the risk of localized shortage in the upper North Island region. Our review of Transpower's analysis supports this finding. We are also aware that Transpower's regional assessment was limited in scope. For that reason we cannot rule out the possibility of similar issues existing in other regions.
4. Finally, there is the possibility of something happening that we have not considered. While we believe we have a reasonable understanding of how the market will react, it is impossible to predict all the possible effects of a TPM change with certainty.

6.1 A transitional peak based charge

One potential transitional measure is a temporary peak-based charge coinciding with a TPM change. Any such charge would affect the incentives on and behaviour of DG and DR. If a temporary peak-based charge closely resembles the RCPD charge in size and design, then we would expect little change to the status quo incentives and hence security risks in the transition. However, such a charge could also potentially defer or reduce the anticipated benefits from a new TPM.

On the other hand, a transitional charge that is more targeted could assist in realising anticipated TPM benefits. However, such a charge could also be uncertain in its effects if it differed greatly from the RCPD charge, with some risk of unexpected outcomes (i.e. different to both the status quo and the no-peak charge scenario considered in this report).

6.2 Alternative transitional measures

There are other possible options to mitigate security risks associated with a transition. For example, Transpower has highlighted an existing risk in the WUNI region which would be compounded by withdrawal of the RCPD charge. To mitigate this particular risk, Transpower could contract with parties in the region using its DR procurement process.

The same process could potentially be extended to any other regions where a particular risk is identified.

A similar approach could be used with DG providers in affected region.

6.3 Effectively an insurance product

The main benefit of any transitional measure is to provide insurance that nothing unexpected happens with the removal of RCPD.

Based on present information, Concept does not consider it likely that there will be costly, unanticipated effects from removing the RCPD charge. However, if the insurance is cheap “enough”, then the rational decision can be to purchase it, even if it will probably not be needed.

We do not have sufficient information to calculate the relevant costs and benefits and form a view on whether such insurance is efficient.

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[76]. 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 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,[77] and the firm capacity contribution from hydro DG plant is reduced by 66 MW.[78]

Ripple control of hot water cylinders (HWCs)

A 2018 Commerce Commission survey indicated that there was approximately 830 MW of "Load control capacity from ripple control" in New Zealand.

This is the most recent source for data on hot water ripple control. However, we suspect that EDBs have interpreted "Load control capacity from ripple control" in subtly different ways (and one party has not provided a value at all) so the reported data is not entirely consistent between EDBs, and should not be taken at face value.

There are many ways of quantifying ripple control capacity. One interpretation is the sum of the individual heating elements for all hot water cylinders connected to a ripple control device. For example, if there were 1000 2 kW hot water cylinders of ripple control, this would be reported as 2 MW. Another interpretation is the coincident peak available across the EDBs network. Of the hypothetical 1000 cylinders, only a portion will be consuming power at any one time, resulting in a substantially lower peak value. We estimate that only about 20% of hot water cylinders will be consuming power at any one time, meaning that the second method produces values about 20% that of the first. [79]

The Commerce Commission survey also provided data for "Estimated number of ICPs with ripple control". This question is less open to interpretation, and so we believe this data is more reliable.

Combining the two data series, it's possible to work out the purported ripple control capacity per ICP, and this varies greatly between EDBs. The highest "capacity per ICP" is just over 2.5 kW, while the lowest is slightly under 0.18kW. While we would expect some variation between EDBs, this is more than a ten-fold difference, which is unlikely if the numbers were reported on a consistent basis. It appears likely that the EDBs with 1.5-2.5 kW per ICP are not reporting a coincident peak, but a sum of individual hot water cylinders, which is not appropriate for our purposes.

[76] 'Security of Supply Annual Assessment 2019'
[77] See section 4.3.4 of ibid.
[78] See Table 6 and Table 7 of ibid.
[79] 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

Accordingly, we do not use the total MW quantity reported in the survey "as is". However, there is still valuable data in the survey. The number of ICPs is very useful for determining where DR response might occur. Additionally, we have estimated a typical peak contribution per ICP from those EDBs that appear to have reported on a coincident peak basis. This allows us to estimate the available ripple control during each network's coincident peak.

However, we need to know the ripple control during national peak periods, so this value is de-rated slightly based on the correlation between each EDB's peak demand and national peak demand.

We estimate that the corrected national coincident peak total from the Commerce Commission data is about 644MW.

We have also estimated the available ripple control load using a "top down" and "bottom up" basis. The bottom up approach considers the number of occupied dwellings, the percentage with an electric hot water cylinder and the penetration of ripple control. The top down approach starts with peak national demand, and considers the percentage that can be attributed to residential and the percentage of that which is hot water load.

These two checks produce similar results (681 and 676 MW respectively). Accordingly, we have assumed that the available hot water ripple control load is about 644 MW.

Of this available controllable capacity, we have estimated the extent to which ripple control will continue to be actively used. The assumptions are set out in section 3.3.

Table 9 - Summary of EDB HWC

EDB	Quantity of DR available (MW)	Currently offers IL	Correlated with regional load	Expected outcome
Alpine Energy	10			May no longer control
Aurora Energy	35		Yes	Continue to manage for own purposes
Buller Electricity	1			May no longer control
Centralines	1		Yes	Continue to manage for own purposes
Counties Power	23	Yes	Yes	Continue to manage for own purposes/ offered as IL instead
Eastland Network	9		Yes	Continue to manage for own purposes
Electra	18			May no longer control
Electricity Ashburton	3			May no longer control
Electricity Invercargill	7			May no longer control
Horizon Energy	4			May no longer control
Mainpower	14		Yes	Continue to manage for own purposes
Marlborough Lines	8		Yes	Continue to manage for own purposes

Nelson Electricity	2			May no longer control
Network Tasman	13		Yes	Continue to manage for own purposes
Network Waitaki	4			May no longer control
Northpower	14	Yes	Yes	Continue to manage for own purposes/ offered as IL instead
Orion	147		Yes	Continue to manage for own purposes
OtagoNet	3			May no longer control
Powerco	109	Yes	Yes	Continue to manage for own purposes/ offered as IL instead
Scanpower	3		Yes	Continue to manage for own purposes
The Lines Company	8			May no longer control
The Power Company	11			May no longer control
Top Energy	10			May no longer control
Unison	13		Yes	Continue to manage for own purposes
Vector	131	Yes	Yes	Continue to manage for own purposes/ offered as IL instead
Waipa Networks	16		Yes	Continue to manage for own purposes
WEL Networks	11	Yes		May no longer control
Wellington Electricity	12	Yes	Yes	Continue to manage for own purposes/ offered as IL instead
Westpower	2			May no longer control

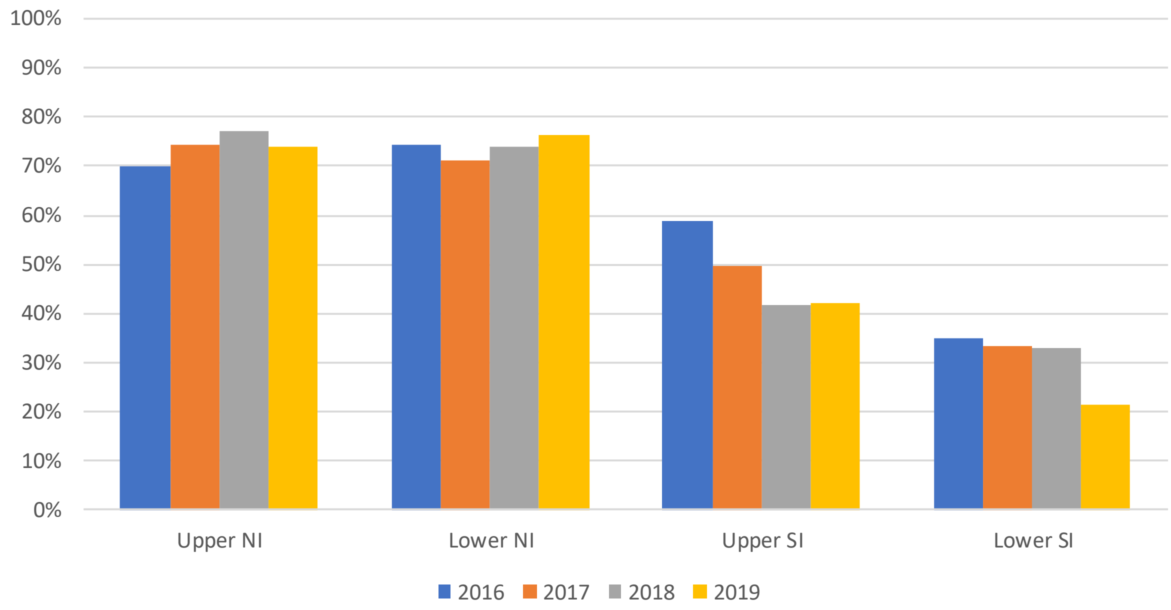
In total, we estimate that there is 95 MW of DR that will face significantly reduced incentives to operate during regional peak periods.

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. Figure 18 shows that even in the North Island, less than 80% of national peak periods were also regional coincident peak periods. The results are even lower in the South Island.

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.

Figure 18 - Percentage of national peak periods that are RCPD100 periods



Appendix C. 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.[80]

Our analysis is based on observed grid load. We have been unable to distinguish between a reduction in load or increased output from any on-site generation. This will not affect total results, but may lead to a misallocation between DG and DR response.

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 and behaviour 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 or respond significantly to high prices.

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. May stop responding if the RCPD signal no longer exists and nodal prices are not sufficiently high to trigger their price-driven response.

Table 10 summarises the categorisation of the industrial loads. The load tranches that potentially meet the above criteria are shaded.

Table 10 - Industrial user demand

	Node	Typical net load (MW)	Responds to nodal price of ($/MWh)	Typical RCPD response quantity (MW)
Non price responsive	**KAW0112**	**11**	**N/A**	**0**
Non price responsive	**ASB0661**	**50**	**N/A**	**0**
Non price responsive	**EDG0331**	**40**	**N/A**	**0**
Non price responsive	**KAW0111**	**10**[81]	**N/A**	**0**
Non price responsive	**MNG1101**	**6**	**N/A**	**0**
Non price responsive	**TNG0111**	**25**	**N/A**	**0**
Non price responsive	**TWI2201**	**620**	**N/A**	**0**

[80] This may be because of inaccuracies in real time price signals available to the load.

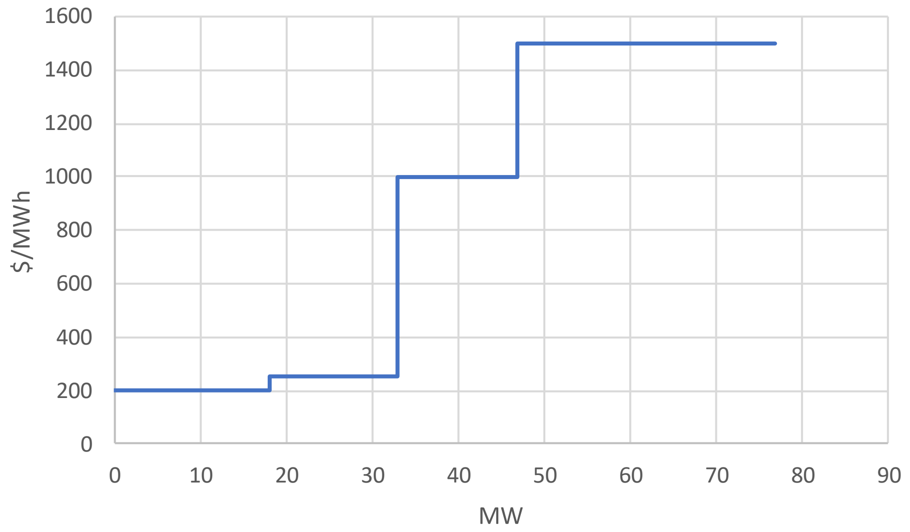
[81] KAW0111, KIN0112, KIN0113 all have significant onsite generation

Nodal price responsive	**KAW0113**	**30**	**200**	**18**
Nodal price responsive	**KIN0111**	**25**	**1000**	**8**
Nodal price responsive	**KIN0112**	**14**	**1000**	**1**
Nodal price responsive	**KIN0113**	**29**	**1000**	**0**
Nodal price responsive	**WHI0111 tranche 1**	**40**	**1000**	**5**
Nodal price responsive	**WHI0111 tranche 2**	**15**	**250**	**15**
RCPD responsive	**GLN0331**	**80**	**N/A**	**30 (50 in sensitivity case)**

The bid information from Table 10 can be used to develop a nodal price response curve for major industrial load that responds to spot price or RCPD signals.

This 'supply curve of industrial DR' is shown in Figure 19.[82] We are mostly interested in the amount of demand that responds to nodal prices between about $165/MWh (the observed average nodal price in system peak periods) and about $980/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:

- About 33 MW of load is expected to respond at prices of between $200-250/MWh – we do not expect this tranche to be affected by the TPM changes, because a small uplift in peak nodal prices would be sufficient to induce demand response. However, a more conservative

[82] 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.

approach would be to assume no uplift in prices, in which case this tranche may no longer respond during peak periods.

- There is a 14 MW tranche of demand, whose bids indicate an intention to curtail at $1,000/MWh, and which has responded to RCPD in the past. A more significant uplift in nodal prices would be required to curtail this demand, and we assume that it would still operate during peak periods.
- Finally, there is a 30 MW tranche of load that responds in RCPD periods, but which does not bid its load below $5,000 MWh. This may reflect the inflexibility of such load – it is able to schedule production to avoid likely RCPD periods, but it cannot quickly respond to a nodal price. This tranche is also 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 44 MW.

Our analysis places more weight on observed response to RCPD periods than bidding behaviour. This is because we believe actual behaviour to be a better indicator of future behaviour than indicated behaviour (especially with no financial penalty for inaccuracies).

There is a large quantity of demand (in excess of 100 MW during most periods) that is bid at about $1,000 $/MWh but which does not appear to respond to RCPD. Taken at face value, this implies that if under the new TPM prices were more likely to exceed $1,000/MWh during times of system stress periods, there might be an *increase* in demand response from major industrial users.

We note that the assumed response from major industrial users is lower than Concept’s 2016 report. Recent nodal prices have been significantly higher than those in 2015 and it is likely that this has changed the way that price sensitive demand operates.