TPM 2019 Cost benefit analysis

Initial review

NZIER report to MEUG

1 October 2019

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Key points

Scope of this analysis

MEUG has asked NZIER for advice on whether the cost benefit analysis (CBA) for the 'Transmission pricing review 2019' (TPM 2019). Is robust. In view of the complexity of the CBA the scope of this advice has been narrowed to a stocktake of current aspects of the CBA to consider.

Benefit of more electricity use at peak is overstated

Most of the net benefit in the Electricity Authority (EA) Transmission Price Methodology proposal (TPM 2019) cost benefit analysis (CBA) arises from:

- Benefit to distribution connected consumer of much lower electricity prices over the 1,600 peak demand periods (due to the removal of RCPD charge) which encourage them to buy more electricity at a time when it is most valuable to them
- Generators meet the increased demand for electricity at lower average wholesale price than forecast if the RCPD remains in place.

This benefit relies on a future shift by EDB and retailers to a new form of time of use pricing which concentrates the effect of the RCPD charge into a much shorter peak demand period than currently used by EDB.

because the RCPD signal is probably much weaker than estimated in the CBA

For the benefits modelled in the CBA to be realised mass-market consumers need to receive a much stronger price signal about the transmission costs during the EA peak demand period (covering only 1,600 trading periods) than is sent by current EDB pricing.

Analysis of the pricing methodology of the 10 largest EDB[1] which account for about 80 percent of the interconnection charges paid by EDB indicate:

- the typical definition of 'peak demand'[2] period for EDB covers about 4,140 trading periods, approximately 2.6 times the 1,600 peak demand period used in the TPM 2019 CBA.
- Most EDB do not recover their interconnection charges through energy delivered charge only during peak demand periods
- EDB consumers usually include at least three major groups: residential mass-market, commercial and industrial which face different types of transmission recovery charge. However, the CBA modelling treats EDB consumers as a single group.

1 In descending order of EDB revenue: Vector, Powerco, Orion, Wellington Electricity, Unison Networks, Aurora, Northpower, The Power Company, Alpine Energy and Top Energy

2 Weekdays between 7:00 to 11:00 and 17:00 to 21:00 or 16 trading periods per weekday. Some EDB split their ToU price bands into 'day' and 'night'.

and increased generation at lower prices seems unlikely to be the central scenario

The CBA modelling also indicates that average wholesale electricity prices will be on average about one percent lower if the RCPD charge is removed than would be the case if the RCPD change is retained due to increased generation investments. The implication in the issues paper is that wholesale price fall occurs because the increase in demand over peak periods increases the number of periods for which new generation is profitable (possibly because it allows a more efficient mix of generation).

CBA modelling excludes distribution costs

The CBA allows for the need to bring forward investment in the Transpower grid capacity in response to the increase in peak demand but the estimated cost to consumers is low.

The CBA does not allow for the potential need for EDB to increase investment in their network to cope with increases in peak demand but argues that:

- if the investment was required it would be efficient
- EDB have spare capacity.

Discussion of RCPD impact on peaks

One of the arguments that has been made against removing the RCPD charge is that the peak load currently discouraged by the RCPD charge will require grid 'over-build' if the charge is removed. The EA and Transpower have discussed this risk in qualitative terms and the EA has given Transpower the option to make a case for a transitional peak charge – a more pragmatic approach than TPM 2016.

10 year reset for AMD is a major change from TPM and EDB annual reset for

The TPM 2019 discussion of allocators of common or 'residual' charges includes two separate components:

- a proposed change in the denominator from regional coincident peak demand to anytime maximum demand or share of annual load (in response to stakeholder concerns about the 'after diversity' advantage of distribution connected customers)
- setting the allocator using averages over the past 5 year and only changing the allocator with an extended lag of five to 10 years rather than the current approach of annual reset.

The EA argues that choosing allocators that are difficult for grid users to influence by altering their short term grid usage will make the methodology durable and the charging regime more certain for grid users. There are three potential disadvantages to mechanisms designed this way. They:

- embed historical, inefficient, asset usage patterns into the re-allocation of costs
- do not consider the current excess capacity of grid assets
- only respond to changes in asset usage with a very long lag.

Contents

1 Problem definition 1
   1.1 Under use of the grid 1
   1.2 Counterfactual continuation of the current RCPD allocation 1
   1.3 Preference for nodal pricing as a signal of congestion 1

2 Benefits and Costs 2
   2.1 Key benefits 2
   2.2 Price reductions and volume changes 2

3 Assessment of benefits 3
   3.1 Benefit of more electricity use at peak is overstated 3
   3.2 The RCPD signal is probably much weaker than estimated in the CBA 4
   3.3 Who receives the RCPD signal? 5
   3.4 CBA assumptions do not match general EDB approach 5
   3.5 Individual EDB recovery of Transpower charges 6
   3.6 CBA modelling excludes distribution costs 8
   3.7 EA and Transpower discussion of RCPD impact on peaks 8

4 Common (residual) charge allocators 10
   4.1 RCPD annual reset to AMD or load with 10 year reset 10
   4.2 Is it ‘consistent’ 10
   4.3 Contribution to the need for grid expansion 10
   4.4 10 year reset for AMD is a major change from current TPM and EDB practice 11
   4.5 EDB cost allocation approaches 11

Appendices

Appendix A EDB pass-through of Transpower charges 12

Figures

Figure 1 Assumed mass market exposure to time-of-use electricity prices 3

Tables

Table 1 EDB interconnection charges....5
Table 2 CBA modelling assumptions and EDB pricing 6
Table 3 EDB recovery of interconnection charges 7
Table 4 Vector recovery of transmission charges 13
Table 5 Powerco recovery of transmission charges 14
Table 6 Orion recovery of transmission charges 15
Table 7 Wellington Electricity recovery of transmission charges 16
Table 8 Aurora Energy recovery of transmission charges 17
Table 9 ‘PowerNet’ recovery of transmission charges 18
Table 10 Northpower recovery of transmission charges 19
Table 11 Alpine Energy recovery of transmission charges 20

1 Problem definition

1.1 Under use of the grid

The EA defines the problems to be solved by the TPM as ensuring:

- ensuring efficient grid use and avoiding the RCPD cost spiral[3] which is implicit in the status quo. The EA argues in TPM 2019 that the RCPD charge has a stronger depressing effect on the electricity consumers connected to the distribution networks than on industrial consumers connected directly to the grid. The EA expects this effect will become more severe over time as the prevalence of time of use pricing increases,
- beneficiaries of investment in the grid (though improved reliability or reduced prices) pay for those investments (rather than the costs being shared across all consumers based on their share of the RCPD). The EA concern for this charge is primarily forward looking and is about ensuring allocatively efficient future investment decisions,

1.2 Counterfactual continuation of the current RCPD allocation

The EA assumption is that continuation of the RCPD allocation of interconnection charges seems to be the appropriate status quo for comparison to the proposal given the lack of alternative proposals that had material support from market participants. The two main charges proposed in TPM 2019 'benefit-based' and 'residual allocated using anytime maximum demand (AMD)' are similar to the main suggested charges in TPM 2016.

Transpower consulted on an operational review of the TPM in 2017 but stopped the process without a clear explanation. The proposed changes were limited in scope compared to the TPM 2019 proposal and for interconnection charges included:

- regionalised postage stamp allocation of the RCPD charges and possibly increasing the number of regions
- reducing the strength of the RCPD signal by increasing the number of peaks or basing some of the charges on the long run marginal cost of the next investment

Submitters generally supported an operational review but Transpower did not develop the proposals beyond a high level description

1.3 Preference for nodal pricing as a signal of congestion

The EA also has a strong view that in the long term nodal pricing (locational marginal pricing) is a more efficient signal of congestion on the grid and the need for additional investment in grid capacity than RCPD charges. Nodal pricing is part of the CBA model structure.

[3] Issues Paper page vii

2 Benefits and Costs

2.1 Key benefits

The EA has estimated the net benefits of the TPM proposal at $2.7 billion (with a range of $0.2 to $6.4 billion) comprising:

- $2.4 billion from reducing the wholesale price of electricity and encouraging increased use at peak times when consumers value it most highly
- $0.2 billion from avoiding inefficient in technologies such as batteries to avoid peaks
- $0.1 billion from more efficient investment in transmission and generation by allocating the costs to those who benefit.

Our analysis of the CBA focuses on the estimation of the benefits and risks of the removal of share of regional coincident peak demand (RCPD) as an allocator of interconnection charges.

2.2 Price reductions and volume changes

The price reductions are measured by changes in wholesale prices and are illustrated in Figure 1 of the issues paper. Peak prices fall by the order of 100 percent in 2020 and then follow a track which is 100 percent lower than the baseline until about 2030.

Volume change is driven by estimated elasticity of demand and distribution connected customers (elasticity -0.054 at peak)are estimated to be more than 10 times as responsive to price signals at peak as transmission connected customers (elasticity -0.003)[4] .

RCPD removal alone reduces peak prices by $136 per MWh (48 percent).

More expenditure on electricity from grid-connected generation will increase peak wholesale energy prices but not by much in comparison to the reduction from the removal of the RCPD charge.[5] Modelling indicates energy prices will be 1 percent lower on average over the modelling period due to generation investments.[6] Off-peak prices, initially rise by 19 percent but then fall 30 percent due to increased generation capacity

4 Issues paper page33

5 Issues paper page37

6 Issues paper page 38 4.97, 4.98 and 4.100

3 Assessment of benefits

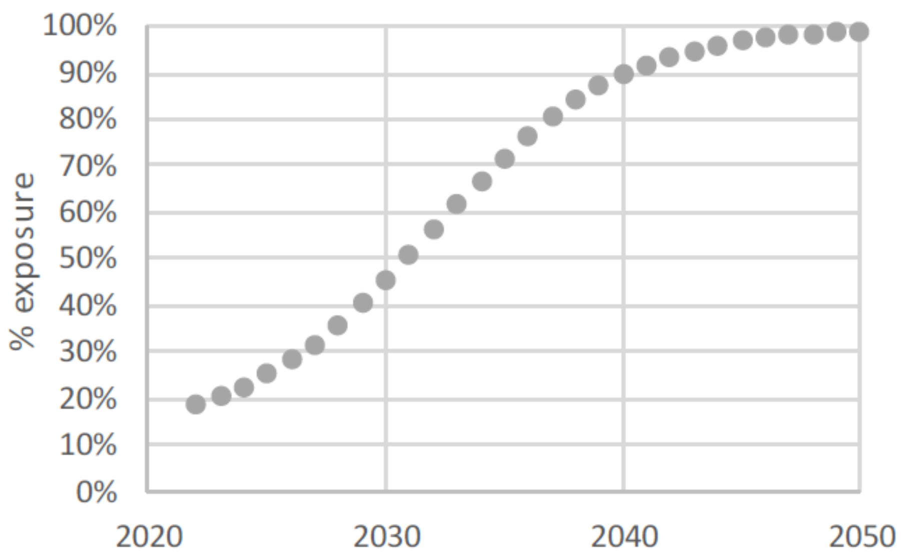
3.1 Benefit of more electricity use at peak is overstated

Most of the net benefit in the Electricity Authority (EA) Transmission Price Methodology proposal (TPM 2019) cost benefit analysis (CBA) arises from:

- Benefit to distribution connected consumer of much lower electricity prices over the 1,600 peak demand periods (due to the removal of RCPD charge) which encourage them to buy more electricity at a time when it is most valuable to them
- Generators meet the increased demand for electricity at lower average wholesale price than forecast if the RCPD remains in place.

The TPM 2019 CBA acknowledges that most (81 percent) of distribution connected consumers are not affected by (retailer) time of use (ToU) pricing[7] and therefore not affected by the concentrated RCPD signal over the peak demand period. However, the CBA modelling assumes that the proportion of mass market consumers exposed to ToU pricing will increase to 50 percent by 2032 and reach 100 percent by 2050 as shown in Figure 1.

Figure 1 Assumed mass market exposure to time-of-use electricity prices



Source: Electricity Authority [8]

This assumption seems to be independent of the changes proposed in TPM 2019 but seems to be the major driver of the increase in benefits from the removal of the RCPD charge over the modelling period. The CBA sensitivity analysis does not seem to include different scenarios for the timing of adoption of TOU charging by both EDB and retailers.

7 'CBA approach, methods and assumptions, Technical paper' page 17. The EA implies that the 19 percent affected by ToU tariffs is a low estimate of the starting point. It is not clear from the EA comments whether the ToU tariffs include exposure to just the RCPD recovery or whether they include recovery of EDB charges and exposure to movements in wholesale electricity prices.

8 'CBA approach, methods and assumptions, Technical paper' page 18

3.2 The RCPD signal is probably much weaker than estimated in the CBA

For the benefits modelled in the CBA to be realised mass-market consumers need to receive a strong price signal about the transmission costs during the peak demand period under the status quo. As well as the share of consumers on retailer ToU pricing plans the strength of the RCPD price signal felt by distribution connected customers also depends on:

- how electricity distribution businesses pass-through transmission costs to mass-market and commercial consumers.
- the proportion of customers on time of use pricing plans with their EDB

Analysis of the pricing methodology of the 10 largest EDB[9] which account for about 80 percent of the interconnection charges paid by EDB indicate:

- the typical definition of 'peak demand'[10] period for EDB covers about 4,140 trading periods, approximately 2.6 times the 1,600 peak demand period used in the TPM 2019 CBA. The effect on the CBA modelling is that even if the RCPD charge was passed on in full as part of EDB peak pricing, the average price signal would be smaller than that modelled in the CBA and would apply over two of the CBA modelling periods (peak and shoulder) with two different demand elasticities
- Most EDB do not pass-through most of their interconnection charges through per MWh peak demand pricing for several reasons:
  - mass-market consumer adoption of ToU pricing is low (Vector, Wellington Electricity Lines and Aurora)
  - transmission charges are recovered at different rates for peak and off-peak periods (Powerco Eastern network, Northpower) or as a combination of fixed daily and volume charges (Orion, Unison, The Power Company, Alpine Energy and Top Energy)
  - transmission charges are primarily allocated using a combination of peak demand measures (Orion).

Together these factors indicate that the actual peak demand pricing signal sent by EDB transmission cost recovery charges to electricity retailers is not only much weaker than estimated in the CBA modelling but also varies across EDB regions. The CBA assumes that the RCPD signal in the status quo will become more intense over time as consumers are moved to TOU pricing and the interconnection charges are recovered over a much shorter peak period than is currently used by EDB. This requires both EDB to standardise their tariff structures and retailers to pass them on in their pricing. The CBA does not explain why the continuation of the status quo alone would lead to these outcomes.

The following tables compare the definition of peak period, penetration of ToU charging and key customer groups for the 10 largest EDB[11].

9 In descending order of EDB revenue: Vector, Powerco, Orion, Wellington Electricity, Unison Networks, Aurora, Northpower, The Power Company, Alpine Energy and Top Energy

10 Weekdays between 7:00 to 11:00 and 17:00 to 21:00 or 16 trading periods per weekday. Some EDB split their ToU price bands into 'day' and 'night'.

11 The 10 largest EDB recovered about 75 percent of interconnection charges and about 85percent of EDB interconnection charges in 2017/18 based on data in 'Transpower Information Disclosure Schedules F1-6, G1-8, SO1, Year ended 30 June 2018' SCHEDULE F6: REGULATED REVENUE, F6(iii): Customer Charges

3.3 Who receives the RCPD signal?

The main benefit of removing the RCPD based allocation of Transpower interconnection charges modelled for TPM 2019 is the increase in electricity use by EDB connected customers during a peak period defined as 1,600 trading periods.

For this benefit to be realised as modelled for the status quo, EDB need to recover interconnection charges through a price signal that applies to the peak period only and this signal needs to be passed on by the electricity retailer to the consumer. This section compares the assumptions in the TPM 2019 proposal to the current EDB pricing practice for the largest EDB which account for more than 80 percent of the interconnection charges recovered form EDB consumers and more than 70 percent of all interconnection charges.

Table 1 EDB interconnection charges

Interconnection charges for ten EDB

EDB	2017/18 charges			2018/19 charges		
	Value ($m)	Share of total	Share of EDB	Value ($m)	Share of total	Share of EDB
Vector	197.6	28%	31%	183.5	28%	31%
Powerco	89.3	12%	14%	81.6	12%	14%
Orion New Zealand	65.2	9%	10%	65.8	10%	11%
Wellington Electricity	58.3	8%	9%	52.9	8%	9%
Unison Networks	28.0	4%	4%	26.5	4%	5%
Aurora Energy	22.7	3%	4%	19.7	3%	3%
PowerNet	22.6	3%	4%	21.5	3%	4%
WEL Networks	20.8	3%	3%	19.2	3%	3%
Northpower	18.7	3%	3%	17.4	3%	3%
Alpine Energy	13.3	2%	2%	11.0	2%	2%
Total	523.3	73%	83%	488.1	74%	84%

Source: Transpower Information Disclosure Schedules, Year Ended 30 June 2018

3.4 CBA assumptions do not match general EDB approach

The CBA modelling of TPM 2019 makes three simplifying assumption about the pass-through of Transpower interconnection charges into wholesale electricity prices. These assumptions are compared to high level observation about current EDB pricing in Table 2.

Table 2 CBA modelling assumptions and EDB pricing

Indications of that CBA model may over-estimate the strength of the RCPD signal

CBA model assumption	EDB practice	Impact on CBA model
EDB connected consumers can be modelled as a single load group on a uniform price structure	EDB have residential, commercial and industrial consumers on different pricing structures. Industrial and commercial customers account for about half of EDB load but about one third of the interconnection cost recovery	CBA elasticity estimates may overstate responsiveness of commercial and industrial load to a change in price signals
CBA modelled peak is 1,600 trading periods	EDB peak period for those with ToU pricing varies between 2,600 to 4,160 trading periods[12]. Some EDB only distinguish between 'day' and 'night' rates	CBA model overestimates the intensity of the peak price signal because it is concentrated in a period that is 40 to 60 percent of peak period used by EDB
ToU pricing coverage by EDB can be modelled as a charge that is only recovered during the peak period	Nearly all EDB either recover interconnection charges over both peak and non-peak periods or with a combination of fixed and variable charges	CBA model will overestimate the size of the change in peak period electricity price from removal of the RCPD because not all of the

Source: NZIER

The following section describes the recovery of Transpower charges listed in Table 1 as a starting point for estimating the difference in the CBA modelling of the RCPD peak demand period price signal and the price signal that is could be sent by the current EDB pricing if it was fully passed by electricity retailers.

3.5 Individual EDB recovery of Transpower charges

Table 3 summarises the key elements of EDB interconnection recovery.

12 The narrowest definition of peak period for the 10 EDB listed in this section is 07:30 to 09:00 and 17:30 to 20:00 on weekdays. For larger EDB the more common definition of peak period is 07:00 to 11:00 and 17:00 to 21:00 on weekdays.

Table 3 EDB recovery of interconnection charges

Charges used by EDB to recover interconnection charges and peak period

EDB	Share of EDB energy delivered 2018	Main recovery method for residential mass market	Estimated peak demand price signal as proportion of CBA assumption
Vector	26.2%	Uniform c/kWh delivered for residential consumers and fixed demand or daily charges for commercial and industrial consumers	13%
Powerco	15.1%	Combination of peak c/kWh and uniform c/kWh delivered	27%
Orion New Zealand	9.9%	Combination of fixed demand charges (share of RCPD or AMD) and uniform c/kWh delivered	18%
Wellington Electricity	7.2%	Combination of fixed daily charges and uniform c/kWh delivered	14%
Unison Networks	5.0%	Pricing schedules and methodology do not detail how transmission charges are collected but tariff profile looks similar to Vector	13%
Aurora Energy	4.1%	Non TOU c/kWh delivered for residential consumers and fixed demand charges for all other consumers	14%
PowerNet [13]	4.4%	Combination of fixed daily charges adjusted for controllable load and a volume charge '$ per day per kWh'	10%
WEL Networks	3.9%	TOU pricing for nearly all residential consumers with a relatively short peak demand period	64%
Northpower	3.4%	Uniform c/kWh delivered for residential and small commercial consumers. Demand charges for large commercial and industrial consumers	11%
Alpine Energy	2.4%	Uniform c/kWh delivered for residential consumers. Demand charges and uniform c/kWh delivered for commercial consumers. Annual fixed charges for large industrial consumers	9%

Source: NZIER analysis of EDB information disclosures and pricing schedules and methodologies

[13] The PowerNet entity listed in the Transpower Information Disclosure (Interconnection charges) does not exactly match the entities listed in the EDB Information Disclosures to the Commerce Commission. PowerNet and Electricity Southland are not listed in the EDB Information Disclosures to the Commerce Commission. For this analysis PowerNet is defined as The Power Company, Electricity Invercargill, and Otago Net Joint Venture.

The initial strength of the change in EDB price signal due to removal of the RCPD charge modelled in the TPM CBA 2019 is overstated to the extent that the:

- RCPD charge is recovered over a higher number of trading periods than the 1,600 periods assumed in the CBA or does not vary with time of use[14]
- EDB connected consumers include commercial or industrial load that is less responsive to the change in RCPD charges than residential consumers.

3.6 CBA modelling excludes distribution costs

The CBA allows for the need to bring forward investment in the Transpower grid capacity in response to the increase in peak demand but the estimated cost to consumers is low relative to the net present value of the estimated benefits but is the largest cost element of the proposal and accounts for 87 percent of the costs of the proposal.

The CBA does not allow for the potential need for EDB to increase investment in their network to cope with increases in peak demand but argues that:

- if the investment was required it would be efficient
- EDB have spare capacity.

This seems to ignore the fact that EDB costs for mass-market consumers are more than twice grid interconnection costs and does not provide any evidence that EDB on average will be more or less in need of additional capacity than Transpower. If EDB need to bring forward investment to accommodate the additional peak demand encouraged by the removal of the RCPD charge this should be included in the CBA.

3.7 EA and Transpower discussion of RCPD impact on peaks

One of the arguments that has been made against removing the RCPD charge is that the peak load currently discouraged by the RCPD charge will require grid 'over-build' if the charge is removed. Transpower prepared a report 'The role of peak pricing for transmission' on this subject in November 2018. The paper considered two case-study scenarios: a partial withdrawal of load control that would require grid investment to be brought forward and a larger withdrawal of load control that did not respond to nodal price increases.

The CBA discussion of the risks of increase in peak demand following the removal of RCPD charges is qualitative rather than quantitative and highlights the limited understanding of the potential volatility in peak demand that could be caused by removing RCPD charges.

The CBA has 'addressed' rather than fully assessed this issue for now by:

- including the cost of bringing forward the grid investment to roughly meet a partial withdrawal of load control
- giving Transpower the option to propose a transitional peak price signal to manage the risk of a large withdrawal in load control, (The EA stipulation that the peak price signal

14 To indicate the extent to which the CBA modelling overstates the strength of the RCPD signalling we use the estimate from the 'CBA approach, methods and assumptions, TPM issues paper 2019, Technical paper' page 14 paragraph 2.19 that *'approximately 30% of wholesale market expenditure (costs) occur during the top 1,600 trading periods, which account for only 9% of trading periods.'.* This a provisional assumption pending calculation of price and demand data for the selected EDB,

will be transitional reflects the string view of the EA that locational marginal pricing is the most efficient signal of the need for grid investment,)

Giving Transpower more flexibility to propose a transitional peak price signal is a more pragmatic approach than TPM 2016.

3.7.1 Cross-check on risk of load increase with abolition of RCPD

Comparison of the demand by EDB and industrials at say 100 or 200 national coincident peaks with their AMD outside these periods provides a starting point for a rough indication of the potential for increased demand after the RCPD is removed. For 2017 the following direct connect consumers had AMD outside the 200 highest national coincident demand trading periods that was well above their average demand during the 100 highest national coincident demand trading periods: NZ Steel, Norske Skog, Pan Pacific and Winstone Pulp.

4 Common (residual)[15] charge allocators

4.1 RCPD annual reset to AMD or load with 10 year reset

The TPM 2019 discussion of allocators of common or 'residual' charges includes two separate components:

- a proposed change in the denominator from in the denominator from regional coincident peak demand to anytime maximum demand or share of annual load (in response to concerns about the diversity of
- setting the allocator using averages over the past 5 year and only changing the allocator with an extended of five to 10 years rather than the current approach of annual reset.

The rationale in the TPM 2019 proposal for the change is that the 'residual' charges should be treated like a tax, raised as efficiently as possible and be difficult to avoid. The TPM 2019 rationale for replacing the RCPD with AMD or total load is to encourage distribution connected consumers to use the grid more during peak periods.

4.2 Is it 'consistent'

In this section I suggest two other objections to the move to AMD or share of load:

- RCPD is likely to be a better measure of the contribution of consumers to peak demand that justify an increase in grid capacity than consumer AMD because it is an average of periods when the grid is most heavily used
- Setting the allocator on recent history and only amending it after a long lag is inconsistent with the annual reset approach to the allocation of EDB costs and removes an incentive for users to flatten their load profile.

4.3 Contribution to the need for grid expansion

The TPM 2019 rationale for AMD (excluding the reset aspect of the proposal) seems to be that it needs to be measure of peak use that is unlikely to have been tainted by consumer behaviour to lower their share of the measure and reduce exposure to residual charges. However, the CBA focus on AMD does not appear to have considered the following:

- how the maximum demand relates to the peak or average patterns of use for consumers and therefore whether it represents sustained or one-off need for grid capacity
- whether the maximum demand for a consumer occurred at a time of surplus capacity on the grid and therefore does not contribute to congestion or whether it occurs at peak periods and contributes to pressure for additional grid investment.

15 TPM 2019 occasion use of the word 'common' for grid costs that cannot be allocated on the basis of direct benefit to a subgroup of consumers is a much more accurate description of these costs than 'residual' and avoids creating the impression that these costs are small compared to the other costs.

4.4 10 year reset for AMD is a major change from current TPM and EDB practice

The TPM 2019 discussion of allocators of common or 'residual' charges includes two separate components:

- a proposed change in the denominator from regional coincident peak demand to anytime maximum demand or share of annual load (in response to stakeholder concerns about the 'after diversity' advantage of distribution connected customers)
- setting the allocator using averages over the past 5 year and only changing the allocator with an extended lag of five to 10 years rather than the current approach of annual reset.

This proposed approach does not seem to consider the deficiencies of AMD as measure of individual consumer contribution for requirement for investment in additional grid capacity and is much more rigid and delayed than the EDB approach to using AMD in the allocation of distribution charges to consumers.

4.5 EDB cost allocation approaches

EDB prices are reset annually based on a combination of cost allocators, last year's prices and an assessment of the likelihood that the pricing strategy will comply with price quality path set by the Commerce Commission.

EDB use a combination of indicators to allocate costs across their consumers including RCPD, various forms of AMD number of connections etc as well as the extent to which consumers use the high and low voltage networks based on how they connect to the EDB network and their load profile. Typically, these measures are included in a cost of service model which is used as input into the annual setting of EDB charges for the next year. The costs are recovered through a mix of charges including fixed (per connection per day), energy supplied, demand, capacity and power factor charges.

Appendix A EDB pass-through of Transpower charges

A.1 Introduction

This section provides more detail on how the 10 largest EDB recover transmission charges based on the following sources:

- EDB pricing methodologies and pricing schedules for the 2019/20 (effective from 1 April 2019) for the EDB charges by consumer group, definition of peak period and share of transmission charges recovered from consumer groups
- EDB Information Disclosure Schedule 8 for the period ended 31 March 2018 as an estimate the share of total EDB energy delivered for each consumer group.

Unless otherwise stated the EDB listed below allocate interconnection charges to their consumer groups on based on each consumer group's share of RCPD. However, the type of charge used to recover the interconnection fees varies across EDB and across consumer groups. The charge is generally not concentrated over the 1,600 peak trading period used in the TPM 2019 CBA.

(Connection charges are usually allocated using share of after diversity maximum demand rather than RCPD.)

A.1.1 Vector

Vector recovers transmission charges from:

- Residential and small business consumers though a per kWh charge that does not vary with time of use. (Less than 0.4 percent of transmission charges were recovered from residential consumers through ToU[16] charges over 2017/2018.)
- Commercial and industrial consumers through a fixed charge based on demand
- Non-standard consumers through a fixed daily charge.

The proportions of energy delivered and transmission fee recovery by consumer group are shown in Table 4.

[16] The 2019/20 pricing schedule indicates that the number of ICPs on ToU plans have increased but are still a very small proportion of total residential ICPs

Table 4 Vector recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Daily	Demand	Uniform	Peak
Residential	40.0%	0.0%	0.0%	53.0%	0.4%
Business	14.5%	0.0%	0.0%	16.6%	0.0%
Low voltage	12.2%	0.0%	5.6%	4.6%	0.0%
Transformer	18.8%	0.0%	11.2%	0.7%	0.0%
High voltage	7.1%	0.0%	3.8%	0.0%	0.0%
Non-standard	7.4%	4.1%	0.0%	0.0%	0.0%

Source: NZIER analysis of Vector Information Disclosure for 2018 and Pricing Methodology for 2019

Vector's share of total energy delivered by EDB was 26 percent in 2017/18.

The estimated recovery of transmission costs by type of charge in Table 4 suggests that for Vector the initial price signal for peak demand is less than 13 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods and only about 13 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 9 percent of the CBA model estimate (to adjust for the 30 percent of interconnection charges recovered from non-residential consumers).

A.1.2 Powerco

Powerco operates two networks with approximately equal transmission costs but two different methods of cost recovery:

- Western network with transmission costs recovered from:
  - Residential consumers using a charge on energy delivered during Powerco's peak demand period[17] which contains about 4,160 trading periods (about 2.6 times the number of peak periods assumed in the CBA model)
  - Commercial consumers using a fixed daily demand charge based on average contribution to RCPD
  - Large commercial and Industrial consumers (with capacity greater than 1,500 kVA) using a combination of fixed daily charges based on share of RCPD and AMD
- Eastern with transmission costs recovered from:
  - Residential consumers using an anytime charge on energy delivered for about 85 percent of residential customers and a charge on energy delivered during Powerco's peak demand period for about 15 percent of consumers
  - Commercial consumers using anytime charge on energy delivered

[17] This was introduced on 1 April 2019.

- A small group of commercial consumers using peak charges with different rates for winter evening and winter morning peaks, winter day (excluding peaks) and summer day rates[18]
- Large commercial and Industrial consumers (with capacity greater than 300 kVA) using a combination of fixed daily charges based on share of RCPD and AMD

Table 5 Powerco recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Daily	Demand	Uniform	Peak
Unmetered	0.3%	0.6%			
Small	54.2%			27.0%	32.2%
Medium	5.2%		4.7%		
Large	9.9%		8.1%		
Large (Industrial)	30.4%		20.2%		

Source: NZIER analysis of Powerco Information Disclosure for 2018 and Pricing Methodology for 2019

Powerco's share of total energy delivered by EDB was 15 percent in 2017/18.

The estimated recovery of transmission costs by type of charge in Table 5 suggests that for:

- Western network the initial price signal for peak demand is about 41 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate over about 4,160 trading periods and 41 percent of energy delivered is consumed in the EA peak demand period).
- Eastern network the initial price signal for peak demand is less than less than 12 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods and only about 13 percent of energy delivered is consumed in the EA peak demand period).

As the Eastern and Western networks are recovering similar amounts of transmission costs the estimated strength of the price signal for peak demand for the Powerco network as a whole is the simple average of the signal for the two networks – 27 percent. The strength of the signal could be reduced to 16 percent of the CBA model estimate (to adjust for the 41 percent of interconnection charges recovered from non-residential consumers).

A.1.3 Orion

Orion recovers transmission charges from:

18 This group is not included in Table 5 because there the amount of energy delivered to this group appears to be small in comparison to energy delivered to the other groups and there was not enough information to allocate the energy delivered to this group to the different charging periods

- General (includes residential and small commercial) connections[19] through a combination of a fixed daily charge based on peak demand and two c/kWh charges – one for weekdays between 07:00 and 21:00 and the other for nights and weekends
- Major (large commercial and industrial) connections through a fixed daily demand charge based on contribution to RCPD, a capacity charge based on share of AMD and a small charge for nominated capacity (included in the AMD charge in the following table).

Table 6 Orion recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Demand (RCPD)	AMD	Uniform weekday 07:00 to 21:00	Uniform weekend and weekday night
General	73.8%	43.7%		28.6%	6.4%
Major	26.2%	9.9%	11.4%		

Source: NZIER analysis of Orion Information Disclosure for 2018 and Pricing Methodology for 2019

Orion’s share of total energy delivered by EDB was 10 percent in 2017/18.

The estimated recovery of transmission costs by type of charge in Table 6 suggests that for Orion the initial price signal for peak demand is less than 18 percent of the signal assumed in the CBA model (as about 65 percent of the RCPD charge is recovered through fixed charges and the most of the remaining 35 percent is recovered at a uniform rate over 7,280 periods and only about 26 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 13 percent of the CBA model estimate (to adjust for the 21 percent of interconnection charges recovered from major consumers).

A.1.4 Wellington Electricity Lines

Wellington Electricity recovers transmission charges from all consumer groups using a combination of fixed daily charges and c/kWh of energy delivered charges. The c/kWh of energy delivered charges vary with each group but are uniform across trading periods with in each consumer group.

19 Orion applies a similar approach to streetlighting and irrigation connections

Table 7 Wellington Electricity recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Daily	Demand	Uniform	Peak
Residential	n/a	18.3%		44.8%	
General Low Voltage	n/a	6.7%		17.4%	
General Transformer	n/a	1.2%		10.5%	
Streetlights and Non-metered	n/a	0.0%		1.1%	

Source: NZIER analysis of Wellington Electricity Information Disclosure for 2018 and Pricing Methodology for 2019

The estimated recovery of transmission costs by type of charge in Table 7 suggests that for Wellington Electricity the initial price signal for peak demand is less than 14 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods and only about 14 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 9 percent of the CBA model estimate (to adjust for the 37 percent of interconnection charges recovered from non-residential consumers).

A.1.5 Unison networks

Unison's price schedules and pricing methodology do not provide information on what charge types are used to recover transmission costs from individual consumer groups. However, in 2018 most of Unison's revenue from:

- Residential consumers came from c/kWh of energy delivered charges at a uniform rate set according to the type of control Unison has over the load. (Unison had a small proportion of residential consumers on TOU pricing in 2018. The peak period for this pricing plan Is weekdays 07:00 to 11:00 and 17:00 to 21;00 covering 4,160 trading periods per year.)
- Commercial consumers came from fixed daily of demand charges.

The mix of Unison's distribution tariffs and revenue and definition of peak periods is similar to EDB like Vector which suggests initial price signal for peak demand is less than 13 percent of the signal assumed in the CBA model.

A.1.6 Aurora Energy

Aurora Energy recovers transmission costs from:

- Residential consumers using a c/kWh of energy delivered charge with different rates for the time of year or whether the load is uncontrolled or controlled but without any narrowly focused TOU pricing
- All other consumer groups a fixed c/kW of demand charge based on the consumer contribution to RCPD.

Table 8 Aurora Energy recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Daily	Demand	Uniform	Peak
Residential	45.0%			56.4%	
All other consumers	55.9%		43.6%		

Source: NZIER analysis of Aurora Energy Information Disclosure for 2018 and Pricing Methodology for 2019

The estimated recovery of transmission costs by uniform or demand charge in Table 8 suggests that for Aurora Energy the initial price signal for peak demand is about 14 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods and only about 14 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 8 percent of the CBA model estimate (to adjust for the 44 percent of interconnection charges recovered from non-residential consumers).

A.1.7 PowerNet

PowerNet includes: The Power Company, Otago Net Joint Venture and Electricity Invercargill. These three EDB recover transmission costs all consumer groups using a combination of:

- Fixed daily charges which vary according to consumer group (determined by fuse size) and whether the consumer has significant[20] controllable load
- Volume variable prices expressed as '$ per day per kWh' and set at the same rate for all consumer groups except for one sub-group of low fixed charge residential consumers.

The PowerNet EDB pricing schedules do not directly state how transmission costs are recovered using the various charges.

[20] At least 25% of the total annual energy consumption is separately metered on a ripple controlled tariff.

Table 9 ‘PowerNet’ recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Daily	Demand	Uniform	Peak
Domestic	29%				
Commercial	23%				
Industrial	25%				
Large industrial	23%				

Source: NZIER analysis of Aurora Energy Information Disclosure for 2018 and Pricing Methodology for 2019

The estimated recovery of transmission costs by fixed and energy delivered charges suggests that for PowerNet the initial price signal for peak demand is about 10 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods as only about 10 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 6 percent of the CBA model estimate (to adjust for the 44 percent of interconnection charges recovered from non-residential consumers).

A.1.8 WEL Networks

WEL Networks pricing schedules and pricing methodology do not provide detail on the type of charges used to recover the transmission costs.[21] However nearly all WEL residential consumers are on TOU pricing with the peak periods specified as 07:30 to 09:00 and 17:30 to 20:00 on weekdays. This implies a WEL peak demand period of 2,600 trading periods compared with the CBA modelling assumption of 1,600 trading periods in the peak demand period.

Non-residential consumers pay a mixture of energy delivered, peak demand[22] and capacity charges[23] (which were the main source of revenue from non-residential consumers in 2018

If WEL Networks recover their transmission costs from residential consumers through peak period energy delivered charges, the initial price signal for peak demand would be about 60 percent of the signal assumed in the CBA model.

A.1.9 Northpower

Northpower recovers transmission costs from:

- Residential consumers using a c/kWh of energy delivered charge with different rates depending on whether the load is uncontrolled or controlled but does not have any residential consumers on TOU pricing
- Large commercial and industrial consumers using either:

[21] The WEL Networks Pricing schedule available at https://www.wel.co.nz/UserFiles/WelNetworks/File/Price%20Schedule%202019.pdf states ‘ii. The transmission component of the prices listed equates on average to 25% per price component.’

[22] Separate rates for winter and summer peaks.

[23] Capacity charges were the main source of revenue from non-residential consumers in 2018 and accounted for more than

- a c/kWh of energy delivered charge with different rates depending on whether the load is uncontrolled or controlled or
- c/kVA demand charges with different rates for shares of AMD and RCPD

- Very large industrial consumers using a fixed $/kW/month demand charge.

Table 10 Northpower recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Daily	Demand	Uniform	Peak
Mass market	43.0%			58.0%	
Large Commercial (Demand based)	7.9%		7.5%		
Very large industrial	49.1%		34.5%		

Source: NZIER analysis of Northpower Information Disclosure for 2018 and Pricing Methodology for 2019

The estimated recovery of transmission costs by uniform or demand charge in Table 10 suggests that for Northpower the initial price signal for peak demand is about 11 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods and only about 11 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 5 percent of the CBA model estimate (to adjust for the 42 percent of interconnection charges recovered from non-residential consumers).

A.1.10 Alpine Energy

Alpine Energy recovers transmission costs from:

- Residential consumers using a c/kWh of energy delivered charge with different rates depending on whether the load is uncontrolled or controlled but does not have any residential consumers on TOU pricing
- Commercial consumers (not on TOU pricing) and industrial consumers on (TOU pricing) using a mixture of c/kWh of energy delivered and fixed demand charges
- Large industrial consumers using a fixed annual charge based on demand.

Table 11 Alpine Energy recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Annual	Demand	Uniform	Peak
Mass market	29.9%	0.1%	0.0%	31.4%	
Commercial (no TOU)	26.5%	0.0%	8.8%	24.2%	
Industrial (TOU)	21.6%	0.0%	11.9%	6.2%	
Large Industrial	22.0%	17.3%	0.0%	0.0%	

Source: NZIER analysis of Alpine Energy Information Disclosure for 2018 and Pricing Methodology for 2019

The estimated recovery of transmission costs by uniform or demand charge in Table 11Table 8suggests that for Alpine Energy the initial price signal for peak demand is about 9 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods and only about 9 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 6 percent of the CBA model estimate (to adjust for the 36 percent of interconnection charges recovered from industrial and large industrial consumers).