Assessment of the TPM proposal's costs and benefits

XX XX 2019

7 Economic behaviours under the TPM proposal with an estimated net cost

Introduction

7.1 This section describes:

(a) the economic behaviours under the TPM proposal, and under the alternative proposal, that we estimate would have a net economic cost

(b) the estimated net economic cost of each of these behaviours.

7.2 We assume the proposal is implemented in 2022. Unless otherwise stated, all dollar values are in real (2018) dollars and are the present values

We have adopted a conservative approach to quantifying TPM reform costs

7.3 As with the quantification of TPM reform net benefits, quantifying TPM reform net costs is subject to a high level of uncertainty over:

(a) the course of future events, and

(b) future decisions that are inherently unknowable now.

7.4 Among other things, TPM reform net costs will depend on the extent to which industry participants accept reasonable trade-offs between cost, effectiveness and perceptions of equity.

7.5 Against this background, we have adopted a conservative approach to counteract the well-known phenomenon of optimism bias in CBAs. Our estimate of net economic costs in this section may be excessive. There will be opportunities to reduce or otherwise manage TPM reform costs, by way of effective governance and management of the TPM reform process. The discussion in this section should not be seen as a rigorous exercise in budgeting TPM reform costs. Instead, it should be considered in the context of testing whether the net benefits of the TPM proposal are likely to exceed the net costs.

We have applied sensitivities to all our estimates of net costs

7.6 We have applied a sensitivity of +/- 50 percent to our estimates of net costs associated with the TPM proposal. We note this is consistent with the approach Transpower and PWC adopted when estimating Transpower's expected costs under a TPM developed in accordance with the proposed TPM guidelines set out in the 2016 Issues Paper.

7.7 In its submission on the 2016 Issues Paper, Transpower noted the difficulty in estimating the size of the TPM development, implementation and ongoing tasks. This difficulty stemmed from the discretion inherent in the proposed TPM guidelines.[23] PWC noted the cost estimate was indicative and might vary by +/- 50 percent.[24]

Economic behaviours estimated to have a net economic cost

Net economic costs under the TPM proposal

7.8 Table 7 summarises the economic behaviours under the TPM proposal that we estimate would have a net economic cost. We estimate these activities would have a net cost of

[23] See p 27 of Transpower's submission on the 2016 issues paper.

[24] See p 6 of Appendix D of Transpower's submission on the 2016 issues paper.

Comment [JS34]: As these costs are passed on to consumers, I suspect we should treat them as a tax and assess "excess burden" from higher prices (crudely speaking a reduction in consumer surplus). However this issue might be best dealt with while assessing benefits i.e. it would be cleaner to e.g. add increased revenue requirements, from higher costs, to the scenarios/model where we assess consumer benefits.

Comment [TS35]: Comment on JS comment: I think it will be important to list all the costs in this section so that stakeholders can see that all the costs have been taken into account.

We must adjust Transpower's estimated TPM implementation costs

7.66 As with Transpower's TPM development costs, Transpower and PWC estimated Transpower's TPM implementation costs based on Transpower preparing a TPM comprising all components of the TPM guidelines proposed in the 2016 Issues Paper.

7.67 Therefore, we must revise Transpower's estimated TPM implementation costs, to exclude our estimate[50] of the costs relating to the components shown in Table 10.

7.68 We must also revise Transpower's estimated TPM implementation costs to exclude the cost of determining the charges for the 11 pre-Guidelines grid investments that we propose be subject to the AoB charge.

7.69 We estimate approximately one third of Transpower's estimated cost to implement a TPM under the TPM guidelines proposed in the 2016 Issues Paper[51] was attributable to:

(a) the additional components in the TPM guidelines proposed in the 2016 Issues Paper

(b) determining the charges for the 11 major grid investments we propose be subject to the area-of-benefit charge.

7.70 This is based on our experience:

(a) modelling the AoB charges for the 11 pre-Guidelines investments we propose be subject to the AoB charging methodology

(b) modelling of the expected impacts on consumers from adoption of our preferred TPM under the proposed TPM guidelines.

7.71 Therefore, we have revised Transpower's July 2016 estimate of its TPM implementation cost to be as shown in Table 16.

Transpower implementation cost under 2019 proposed TPM guidelines

Table 16: Transpower's 2016 estimated TPM implementation costs without additional components

	Effort (days)	Cost
Technology	2,282	$4,083,333
Business process	165	$329,333
Change management	228	$456,667
Sector engagement	68	$115,333
Project management / Governance	228	$456,000
Hardware / Software	0	$1,000,000
Total	2,971	$6,440,667

Source: Electricity Authority

Notes: 1.

[50] Noting we have been unable to obtain Transpower's 2016 estimate of the cost of these components, as an input to this.

[51] Ie, the high complexity scenario in Appendix D of Transpower's submission on the 2016 issues paper.

Comment [WE(50]: Is someone going to have a discussion with Transpower on this assumption?

Comment [PB51]: Absolutely fine by me. Authority's call though.

Comment [TS52]: Transpower have been planning a major revamp of their main IT system involved in transmission pricing. This revamp is going ahead regardless of what happens with the TPM. We need to be careful that this cost does not get included in the implementation cost for the TPM. Transpower's 2016 figure might have included it.

PB: Tim, Jo put the following query to Transpower:

"Did the implementation costs in the PwC report include a full rebuild of your TPM IT system? I presume you were intending it build it from scratch at the time as it needs rebuilding."

Transpower responded as follows:

The (PWC) report describes implementation (set-up and ongoing) costs as change to the four parts of the existing system and its interfaces: metering, assets, pricing and billing; and customer facing.
The PWC report identifies that the system impact is not at the connection asset level:
- . Pages 43 CC01 is for connection assets
- . Page 48 C000 presents that CC01 (inter alia) only indirectly impacts Transpower TPM implementation and are embedded within the additional triggers discussed in this report

Accordingly, we read the PWC report that it has priced the high complexity scenario as the costs for accommodating the changes to the treatment of HVDC and interconnection assets. Hence conclude that the indicative cost to implement the proposed changes (high complexity) remains as ~ $9.7M, level of accuracy +/- 50% (page 25 of PWC report).

DTCs and other stakeholders

Implementation costs under the 2019 proposed TPM guidelines

7.77 Transpower has noted there are no substantial changes to the process for invoicing transmission charges, although several explanatory additions would be needed for the new TPM charges on invoices and other DTC-facing material.[52]

7.78 On this basis, we believe DTCs would face moderate implementation costs if the TPM were to be revised under the 2019 proposed TPM guidelines. We expect these costs would relate primarily to:

(a) understanding and validating the revised transmission charges, particularly the area-of-benefit charge, when these were introduced

(b) updating policies and/or procedures.

7.79 We estimate the incremental resourcing required by a DTC to undertake these activities would be approximately [four weeks] of an analyst's (or equivalent) time. This is an average figure — it would be higher for some DTCs and lower for others.

7.80 Using an average salary of $100,000 for an analyst (or equivalent), the incremental cost faced by each DTC to undertake the activities above would be approximately $4,000. This sums to approximately $370,000 across Transpower's 48 DTCs.

7.81 Some DTCs may need to make IT system changes (eg, distributors incorporating the changed structure of the transmission charges into their invoices to retailers and direct-billed consumers). The "set and forget" nature of the AoB charge means we do not expect DTCs would need to build relatively complex IT systems to verify their transmission charges.

7.82 We have allowed for approximately half (15) of New Zealand's distributors to incur some IT system change costs, with the average of this cost being $20,000. This gives a total incremental cost of $300,000. We welcome feedback from DTCs on the reasonableness of:

(a) the estimated number of DTCs incurring IT system change costs

(b) the estimated average cost of these system changes.

7.83 We may be conservative with our incremental cost estimate. Currently, distributors receive a monthly invoice for transmission services, which they allocate across their customers in a variety of ways. Rather than half of distributors, most distributors might require no change to their IT systems to accommodate monthly invoices calculated using a different TPM. This would be because the distributors' allocation of transmission costs to their customers would not change.

The use of a 'grossing up' approach to calculating load at GXPs would have an incremental cost

7.84 Transpower would require half-hourly metered quantities from embedded/distributed generators if Transpower were to use a 'grossing up' approach to calculating load at GXPs.

Comment [JS56]: I wonder if these costs are offset somewhat by reduced costs associated with e.g. (i) monitoring demand conditions and responding to avoid peak charges under the status quo (ii) administering ACOT payments.

Comment [TS57]: Yes, agree with JS comment. Significant resource goes into these matters from some parties, including distributed generators as well as transmission customers.

Comment [PB58]: Agree, but I've left the discussion of these benefits for the section on net economic benefits.

TS: are these benefits in fact covered in the section on net economic benefits?

Although this raises the question of whether DTCs' implementation and ongoing costs should be included in the section on net economic benefits?

Comment [BR59]: Just a thought – the Authority could commit to assisting parties to understand AoB through a series of workshops or 1 on 1 meetings. This would justify downward pressure on this cost to participants.

Comment [PB60]: Yes, for sure. However, Transpower appears to have made a significant allowance for DTC liaison.

Comment [PB61]: We have informally received an estimate of 4-8 weeks from one of the relatively larger distributors.

Comment [PB62]: The material in this subsection is from a draft Code amendment proposal that the Market Analytics team would like to see implemented.

Comment [BR63]: I can understand how charging small DGs, say, 0.1MW, would require distributors to spend some money. However, perhaps the Authority's DG registry could be used to assist distributors to calculate DG charges. From the Authority's perspective the reconciliation data as is should be sufficient to allocate charges to distributors.

Just to bear in mind – the guidelines as currently written do not land on a threshold/deminimis for charging DG. The Authority has kept options open for charging DG behind the meter. No decision on 0.1MW threshold has ... [2]

Comment [JS64]: I am not convinced this is a cost that needs to be in our CBA (I am unsure). Isn't this a similar issue to the additional components that would only be implemented if net beneficial? The TPM proposal co ... [1]

Comment [TS65]: Response to JS comment: if there is a significant cost here that is attributable to our proposal (assuming we go for a gross load approach) it might be worth calculating so we can report it to the board – ... [3]

52 See p 21 of Appendix D of Transpower's submission on the 2016 issues paper.

Page 51: [1] Comment [JS64]	John Stephenson	21/01/2019 7:04:00 PM

I am not convinced this is a cost that needs to be in our CBA (I am unsure). Isn't this a similar issue to the additional components that would only be implemented if net beneficial? The TPM proposal could be implemented without this. That is, with "grossing up" restricted to cases where generation is metered.

Page 51: [2] Comment [BR63]	Blair Robertson	23/01/2019 6:11:00 AM

I can understand how charging small DGs, say, 0.1MW, would require distributors to spend some money. However, perhaps the Authority's DG registry could be used to assist distributors to calculate DG charges. From the Authority's perspective the reconciliation data as is should be sufficient to allocate charges to distributors.

Just to bear in mind – the guidelines as currently written do not land on a threshold/deminimis for charging DG. The Authority has kept options open for charging DG behind the meter. No decision on 0.1MW threshold has been made. But it does need to be made soon!

This is not a DTC cost, and perhaps not in scope of TPM, but I'll put here anyway: There needs to be a DG identifier in the reconciliation/vSPD datasets. This is perhaps a project in itself. Currently there are data limitations and a requirement for discretionary decision making. Currently I am looking at 100 discretionary decisions around DG and I have nothing to point to but my own judgement after comparing 5 data sources. There will be a cost associated with this.

Page 51: [3] Comment [TS65]	Tim Sparks	22/01/2019 5:06:00 PM

Response to JS comment: if there is a significant cost here that is attributable to our proposal (assuming we go for a gross load approach) it might be worth calculating so we can report it to the board – given that the board has not yet made a decision on the net vs gross issue.

Table 20: Transpower's estimated cost to administer (in years 2–5) a TPM under the TPM guidelines proposed in the 2016 Issues Paper

	FTE increase	Year 2–5 annual cost
Pricing & finance	3	$320,000
Customer solutions	0.5	$50,000
Business enterprise	1	$100,000
Consultation	0.5	$50,000
Reporting & billing	0.1	$10,000
Metering	0.5	$50,000
System planning	0.25	$25,000
Vendor support	1	$200,000
Total	6.85	$805,000

Source: Transpower

Notes: 1.

7.109 We have used these cost estimates as our starting point for estimating Transpower's cost to administer our preferred TPM under the 2019 proposed TPM guidelines. We believe Transpower's effort and cost to administer a TPM under the 2019 proposed TPM guidelines would be like what Transpower faced administering a TPM under the TPM guidelines proposed in the 2016 Issues Paper. This is for the reasons discussed above in relation to the cost of developing and approving a TPM.

We must adjust Transpower's estimated ongoing TPM administration costs

7.110 As with Transpower's TPM development and implementation costs, Transpower and PWC estimated Transpower's ongoing TPM administration costs based on Transpower preparing a TPM comprising all components of the TPM guidelines proposed in the 2016 Issues Paper.

7.111 Therefore, we must revise Transpower's estimated ongoing TPM administration costs to exclude our estimate[56] of the costs relating to the components shown in Table 10.

7.112 We estimate approximately one quarter of the effort in Transpower's 2016 cost estimates for administering a TPM under the TPM guidelines proposed in the 2016 Issues Paper[57] was attributable to the additional components in the proposed TPM guidelines.

7.1 The AoB charge would add complexity to Transpower's pricing and finance team's TPM-related work, and to the amount of liaison, and possibly consultation, Transpower undertakes with DTCs. However, we believe the introduction of a demand charge (one of the components shown in Table 10) would also materially add to Transpower's work. We may be too conservative estimating a 25 percent reduction in Transpower's ongoing administration costs from removing the additional components shown in Table 10. A one third reduction may be more accurate. However, in keeping with the conservative nature of this CBA, we have used a 25 percent reduction.

7.2 Therefore, we have revised Transpower's 2016 estimates of its ongoing TPM administration costs to be as shown in Table 21 and Table 22.

Comment [WE(70]: Is someone going to have a discussion with Transpower on this assumption?

Comment [PB71]: Ditto my previous comment on this point.

56 Noting we have been unable to obtain Transpower's 2016 estimate, as an input to this.

57 As per the above footnote.

Changes in allocative efficiency under the main scenario

8.8 We estimate that, under the main scenario, removing the RCPD charge would produce a net consumer welfare gain of $2,347 million, in present value terms, between 2022 and 2049.[68] Welfare changes have been discounted at a rate of 6% per year.

8.9 This welfare gain includes a consumer welfare improvement of $2,390 million from:

(a) increased consumption during peak demand periods, which has a higher value to consumers than consumption during off-peak periods

(b) lower charges on more price-sensitive consumers and higher charges on less price sensitive consumers

(c) lower charges on mass-market consumers that have comparatively higher demand for energy (i.e. place a higher value on energy).

Comment [EW76]: This is a marked increase in benefits when considered against the Oakley Greenwood CBA. It begs the question, if the OG work was deemed inaccurate is this work "more" inaccurate.

Comment [EW77]: I don't see any evidence of increased transmission, distribution, or generation investment being included in the model to explicitly address this increase in peak demand – as opposed to transmission and generation which is required for forecast demand growth and is included.

Comment [EW78]: How has price volatility been modelled? Arguably to reach these conclusions requires use of a complex model which simultaneously solve for generation strategy, dispatch, and long term expansion of transmission and generation.

8.10 The net consumer welfare gain of $2,347 million includes the $2,390 million consumer welfare improvement adjusted to reflect:

(a) increased transmission loss and constraint excess of $7 million (present value), due to higher peak demand

(b) increased transmission investment costs of $58 million (present value), from increased peak demand

(c) a present valued $21 million transfer of transmission interconnection charges from generation customers to load customers.

8.11 These results come from a model of electricity demand that distinguishes demand by:

(a) 14 areas (backbone nodes)

(b) mass market (distributor) demand and large industrial demand

(c) time of use

(d) energy source:

(e) grid offtake during demand peaks (the top 1,600 trading periods)

(f) demand served by distributed generation during demand peaks

(g) demand met by grid offtake and distributed generation during shoulder periods (the next highest 3,075 trading periods after the highest 1,600 trading periods)

(h) demand met by grid offtake and distributed generation during off-peak periods (the lowest 12,845 trading periods).

8.12 The basis for categorising a typical year's 17,520 trading periods in the manner set out above is a cluster analysis of trading periods, by each of the four transmission pricing regions in New Zealand. The cluster analysis identified six clusters of demand. We chose to take the first two clusters as the peak and shoulder and to combine the subsequent clusters into a single off-peak period. This is because our interest is in peak demand, given its impact on transmission system capacity and costs.

[68] We assume the TPM proposal is implemented in 2022, and 2049 is when our evaluation period ends.

We look first at the effect on electricity demand of changes to transmission charges

8.15 The model of electricity demand considers consumers switching their electricity use between:

(a) different time periods

(b) grid-supplied electricity and electricity supplied by distributed generation.

8.16 Consumers' responses to price changes vary between regions and between large industrial demand and mass market demand. This variation reflects fundamental differences in consumers' electricity demand choices. For example, some consumers place a higher value on using electricity during peak demand periods, because they want to use heating when it is cold or to cook dinner when they get home from work.

8.17 Variations in consumers' price responsiveness also reflect the availability of local, distributed, generation and differences in wholesale energy prices (that reflect the cost of transporting electricity). Consumers' responsiveness to prices tends to increase if prices are relatively higher. For example, consumers supplied by the Marsden backbone node will tend to be more price responsive than consumers at the Benmore backbone node, because the price of energy at the Marsden backbone node is generally 18% higher than the average energy price nationally, while prices at the Benmore backbone node are on average 5% lower. This price difference reflects the extent to which consumers supplied by the Marsden backbone node rely on more transmission network to transport energy to them compared to consumers supplied by the Benmore backbone node.

Comment [EW79]: This is a function of losses and constraints so is not related to transmission pricing.

8.18 Grid exit points with substantial distributed generation can avoid transmission charges under the current TPM, by reducing their share of demand during peak demand periods. For example, the Whakamaru backbone node has significant distributed generation, resulting in electricity offtake from the grid being close to zero during peak demand periods. This reduces overall prices at the Whakamaru backbone node and tends to reduce price sensitivity — a 10% change in prices has a smaller impact if prices are relatively low to begin with.

Comment [EW80]: Is this the case or does it reflect the fact that Whakamaru is a typically a grid injection node and the way the simplified model has been built, the close to zero grid off-take reflects increased dispatch of local generation at peak and has nothing to do with transmission pricing..

8.19 The TPM proposal leads to a significant shift in the incidence of transmission charges. Table 28 shows this. The table is based on projected interconnection revenue, and only takes account of demand response to prices. In other words, the results in Table 28 are from isolating the effects of the TPM proposal on allocative efficiency and consumer demand response.

8.20 In this first step of our modelling, Transpower's forecast revenue comprises:

(a) Transpower's base capital expenditure

(b) Transpower's listed projects,[69] and

[69] As part of each process for setting Transpower's price-quality path for a regulatory control period, the Commerce Commission publishes a list of base capital expenditure projects that:

- Transpower expects to commission during the regulatory control period, and
- must follow the same process for approval as a major capital expenditure project.

Transpower may submit a proposal to the Commerce Commission, seeking approval for one or more of these 'listed projects', up to 22 months prior to the end of the regulatory control period within which the project is commissioned. The approved funding for the listed project is added to Transpower's base capital expenditure allowance as part of the yearly updates to Transpower's allowed revenue. See https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpower-capital-investment-proposals/transpower-listed-projects.

(c) Transpower's approved major expenditure.

8.21 Changes in the incidence of transmission charges translate into changes in prices faced by consumers. Under the current TPM, transmission charges translate into high prices for peak demand. As explained in [the model appendix], we have modelled the RCPD charge as being a charge levied against average MWh consumption during the 1,600 trading periods with the highest MW demand.

8.22 In practice, RCPD charges are much more concentrated than this — targeted at the top 100 coincident peak demand periods. However, the model of electricity demand considers a more diluted price signal, on the assumption that consumers:

(a) do not know which demand periods will attract coincident peak demand charges, and therefore

(b) treat all peak demand periods as potential candidates for attracting a coincident peak demand charge.

Comment [EW81]: But EDBs the "consumers" do know when peaks are going to occur and control load accordingly. Do we then have a chicken and egg situation – is load being controlled to avoid requirements for increased investment in transmission and distribution or to avoid transmission charges. Numerous studies have shown that load control to defer investment is economically efficient.

Table 28: Shares of transmission interconnection revenue by backbone node

Shares of projected real Transpower revenue between 2022 and 2049 (incorporating demand response), for load customers

Island	Backbone node	Baseline		TPM proposal		Change	
		Mass market	Large industrial	Mass market	Large industrial	Mass market	Large industrial
North	MDN	3.1%	--	5.4%	--	2.3%	--
	OTA	29.2%	1.8%	35.8%	2.8%	6.7%	1.0%
	HLY	7.1%	1.0%	8.0%	1.2%	0.9%	0.1%
	TRK	5.1%	0.5%	4.3%	0.6%	-0.8%	0.1%
	WKM	0.0%	--	0.8%	--	0.8%	--
	SFD	2.7%	0.1%	2.5%	0.1%	-0.2%	0.0%
	RDF	3.4%	0.8%	2.6%	0.8%	-0.8%	0.0%
	BPE	2.6%	0.4%	2.8%	0.4%	0.2%	0.0%
	HAY	8.7%	--	7.8%	--	-0.8%	--
South	KIK	2.8%	--	2.5%	--	-0.3%	--
	ISL	14.2%	0.2%	10.9%	0.1%	-3.3%	-0.1%
	BEN	2.4%	--	1.4%	--	-1.0%	--
	ROX	2.4%	--	1.8%	--	-0.5%	--
	TWI	2.0%	9.5%	1.4%	5.9%	-0.6%	-3.7%

Source: Electricity Authority

Notes: 1.

8.23 Our model of consumer demand treats transmission interconnection charges as a $ / MWh charge. Of course, under the TPM proposal this is not how transmission interconnection costs would be charged. However, the approach we have followed in the CBA ensures that, under the demand modelling, consumers still consider the overall cost of electricity when making their consumption decisions. That is, we assume consumers only increase their overall electricity consumption if the average cost of electricity falls relative to other goods and services available to them.

8.24 To implement this assumption, we must convert lump sum transmission costs into a price or average cost equivalent. We assume consumer time of use demand decisions take account of *relative prices* rather than absolute prices. Thus, if the same MWh charge is applied to all times of use, it has no net effect on consumers' electricity demand decisions. Although if all prices increase by the same amount this does reduce consumer purchasing power and results in lower overall expenditure on electricity.

8.25 In general, mass market consumers' electricity use during peak demand periods is more price sensitive than that of large industrial consumers. This reflects the fact that large industrial consumers have already optimised their energy use to avoid consuming electricity when prices are very high. The remaining amount of electricity used by large industrial consumers, during peak periods, is by-in-large less avoidable and less price sensitive than mass market consumers' peak demand.

Comment [EW82]: This is inconsistent with feedback received in interviews with direct connect customers for a VoLL study. Most direct connect customers are price sensitive with respect to energy consumption above some minimum level – what they have hedged.

8.26 Mass market demand also includes automated demand response (ripple control) that, empirically, sees material demand reductions when demand or prices are high and thus translates into observed sensitivity to price changes.

Comment [EW83]: Ripple may be used when demand is high but where is the evidence that it is being used when prices are high? Is there a risk that an assumption that high demand is synonymous with high prices is being made?

8.27 Examples of demand elasticities for mass market demand and for large industrial demand are shown in Table 29 and Table 30. The bold values in the tables, on the diagonals, represent 'own-price' elasticities. This is the change in demand given a change in the price of consumption during that time of use.

8.28 The values either side of the diagonals are substitution elasticities. For example, a 10% increase in the price of grid-supplied electricity at peak is estimated to result in a 4.8% (0.48 per unit change) increase in use of distributed generation at peak at mass market backbone nodes (on average). Conversely a 10% increase in peak prices is estimated to result in a 0.1% (0.01 per unit change) reduction in demand off-peak — indicating that higher prices at peak crowd out consumption at other times by reducing income available to spend on electricity.

Table 29: Mass market demand elasticities

Evaluated at the average expenditure share 2010-2017

	Quantity			
Price	Peak	Distributed generation peak	Shoulder	Off-peak
Peak	**-0.13**	-1.08	-0.29	-0.25

8.33 Table 32 depicts two approaches to charging for transmission services. Under the first approach, a charge levied against average MWh consumption during peak demand periods replaces the current RCPD charge. This first approach captures just the economic effects of removing peak transmission price signals. It does not capture the economic effects of allocating transmission charges based on the benefits that transmission users receive from the transmission investment (including re-allocating the cost of some existing transmission assets based on estimates of the benefit from using those existing assets). It also does not include a reallocation of revenue between load and generation customers.

Comment [EW84]: If you remove a peak charge then in peak periods we would expect to see increased losses and congestion on the transmission system, giving rise to increased energy prices and as a consequence welfare losses.

8.34 Under the second approach to charging for transmission services, revenue is allocated according to:

(a) estimated shares of benefits from some existing assets

(b) shares of benefits from forecast transmission revenue, and

(c) AMD (being the average AMD over the five years prior to the introduction of the proposed changes to transmission prices).[70]

8.35 The price changes in Table 31 reflect this second approach.

Table 32: Consumer welfare, allocative efficiency gains

Present value welfare change 2022-2049

Island	Backbone node	MWh		AoB and AMD	
		Mass market	Large industrial	Mass market	Large industrial
North	MDN	55	--	-71	--
	OTA	1,085	-83	320	-67
	HLY	179	-23	143	-6
	TRK	161	-39	207	-5
	WKM	-41	--	-60	--
	SFD	73	-2	94	0
	RDF	131	-28	157	3
	BPE	57	-11	59	-1
	HAY	343	--	298	--
South	KIK	80	--	96	--
	ISL	429	-1	627	5

70 Our use of the average of the AMD across the past five years is to simplify the modelling. As set out in Table 6, we assume Transpower would apply a 10-year lag, or use such other approach that minimises the incentive on consumers to alter their maximum demand to lower their share of the residual charge.

(b) an **indirect effect** on electricity bills from consumers changing their demand — changing how much they consume overall and/or changing how much they consume at different times of use (say from off-peak to peak) in response to

(i) changes in the relative price of consuming at different times of use

(ii) changes in the overall price of electricity.

8.42 Consumers may prefer the choices they made over how much electricity to consume, and when, before the change in electricity prices. However, they can re-optimise their spending. This re-optimisation — the indirect or substitution effect — means they are not as badly off, in terms of their economic welfare, as a direct price change measure might suggest.

8.43 Current RCPD charges place a premium on grid use during peak demand periods. This premium is not necessarily correlated with costs of supply. RCPD charges are:

(a) not calculated to reflect region-specific transmission capacity, or lack thereof

(b) rise following increases in transmission capacity.

8.44 Removing the premium on peak demand will benefit consumers by reducing costs associated with demand at times when electricity is particularly valuable.

Comment [EW85]: Two points – to what extent do consumers see a peak demand premium because of the current transmission charge allocation method? Would removal of the premium arising from transmission allocations get outweighed by energy price impacts if demand increased in peak periods?

8.45 The value to consumers of using electricity at peak is illustrated by the fact that approximately 30% of wholesale market expenditure (costs) occur during the top 1600 trading periods, which account for only 9% of trading periods.

8.46 Thus, to estimate benefits to consumers we consider:

(a) the value to consumers of demand at peak, based on how much expenditure occurs at peak.

(b) impacts of changes to prices, valued at current expenditure shares

8.47 For example, at 30% of current expenditure shares, peak demand is vastly more valuable than demand at any other time.

8.48 A 50% reduction in prices at peak is expected to result in a 2% increase in demand. Valued at current expenditure shares, this change in demand is worth 2% x 30% x $4,000,000,000 = $24,000,000 annually, assuming fixed expenditure in the baseline.

8.49 In addition, the cost of consuming at peak – irrespective of changes in demand – is on average 50% cheaper. This results in an average cost reduction of $600,000,000.

8.50 Of course, these cost reductions are offset by increased costs of consuming in other periods. Thus we need to deduct costs from other periods.

8.51 A key question for cost benefit analysis is how to value the relative change in costs – in terms of consumer welfare and hence allocative efficiency?

8.52 To answer this question we appeal to conventional economic principles:

(a) revealed preference, which implies that if we observe higher demand for higher priced products those products must be preferred to other lower priced products

(b) diminishing marginal utility of consumption, which implies that consumers get marginally less value out of an additional unit of consumption than they did out of the previous unit of consumption demand declines. The additional investment cost that is measured is the amount of additional revenue required to maintain a stable rate of revenue per MW of peak demand.

8.78 Part of the increase in peak demand for grid services comes from reduced reliance on distributed generation during peak demand periods. Under the TPM proposal, the use of distributed generation during peak demand periods is estimated to decrease — by 5 percent on average between 2022 and 2049. This reflects the fact that under the TPM proposal the relative price of distributed generation, compared to the price for peak grid demand, increases significantly because the price for peak demand falls significantly (from removing the RCPD charge).

Comment [LW86]: How was this calculation arrived at? I'm not sure that I buy into the construct that DG is subject to a security constrained economic dispatch. Or does this just reflect an issue with the simplified used in the analysis?

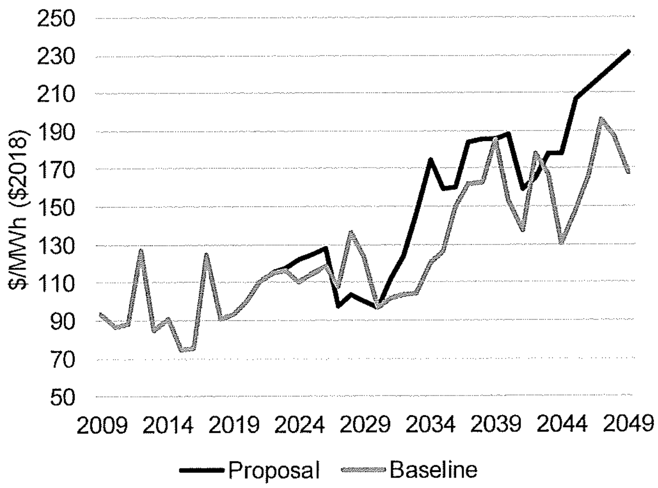
Table 34: Scarcity of local generation, price mark-ups and discounts

Average mark up (local price over national average), all times of use. Scarcity measured by net surplus of load over generation (rounded to 2 decimal places).

Backbone node	Probability of scarcity at peak	Mark-up, scarcity	Mark-up, no scarcity
MDN	1.00	1.18	--
OTA	1.00	1.11	--
HLY	0.00	1.16	1.07
TRK	1.00	1.03	0.88
WKM	0.00	1.04	1.04
RDF	0.98	1.04	1.01
SFD	0.20	1.09	1.03
BPE	0.11	1.10	1.04
HAY	1.00	1.08	--
KIK	1.00	1.08	--
ISL	1.00	1.06	--
BEN	0.00	1.13	0.95
ROX	0.00	1.45	0.97
TWI	0.71	1.03	0.88

Source: Electricity Authority
Notes: 1.

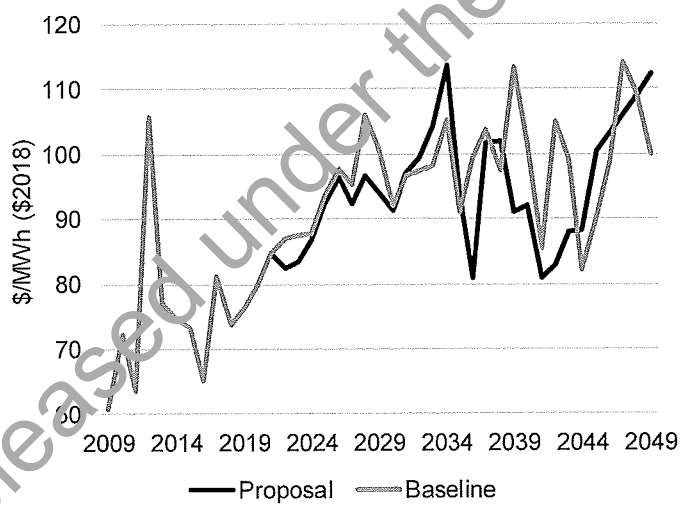
Figure 5: Peak energy price impacts



Source: Electricity Authority

Notes: 1.

Figure 6: Average energy price impacts



Source: Electricity Authority

Notes: 1.

Comment [EW87]: How are transmission losses and constraints captured in these two figures? (5 & 6). Are these based on a security constrained economic dispatch?

8.89 We forecast energy prices will be 1% lower, on average undiscounted, between 2022 and 2049 under the proposal compared to the current TPM.

8.90 Reductions in energy prices are partly because of a reduction in distortions to generation investment under the current TPM arrangements. Existing interconnection charges faced by generators in the South Island reduce returns on investment to generation in the South Island, even where projects exist that are otherwise relatively low cost.

8.91 It is difficult, if not impossible, to completely disentangle the effects this distortion has on generation investment. This is because the current TPM reduces peak demand growth, which reduces the frequency with which new investment is profitable, regardless of transmission prices faced by investors in generation. Furthermore, if lower cost generation is inhibited by transmission costs and is replaced by more expensive generation then this will flow through into higher energy prices, further retarding demand growth and further reducing opportunities to invest.

8.92 With these confounding factors in mind, we have estimated that the costs of the current HVDC charge on South Island generation cause energy prices to be 0.6% higher than they otherwise would be – holding all else constant except the distortionary effect on generation investment. This is due to investment in the South Island being delayed or displaced by more expensive generation. The present value impact on consumers is $198 million.

8.93 This estimate is artificial in the sense that it assumes that there is no distortionary effect on investment, while generators continue to pay HVDC charges. If HVDC charges were instead transferred to consumers, to capture the benefit of removing the investment distortion, this would add additional costs to consumers, depending on how the costs were recovered.

8.94 Notably, the proposal includes a similar distortion, in so far as the area of benefit charge applies to generation and will disincentivise investment in generation in areas that have benefitted from generation investment – particularly in the South Island. We estimate that the costs of this distortion amount to a 1% increase in energy prices on average between 2022 and 2049. The impact on consumers is an estimated cost of $1,270 million (present valued) – again based on comparing projected prices under the proposal and projected prices under an assumption that there is no distortion from AoB charges. The cost in this instance is larger than for the current TPM ($198 million) because prices rise most at during periods of peak demand and peak demand is higher under the proposal.

8.95 That is, reduced investment in the South Island may be efficient if it is offset by higher investment in the North Island (closer to a majority of load) and reduced need for generation investment. Similarly, an increase in generation in other parts of the country, such as the Upper South Island, may also be more efficient if it avoids the need for new transmission investments, even where such generation projects are on the face of it more expensive than alternative investments.

Efficiency of investment in distributed energy resources

8.96 We estimate the TPM proposal would significantly improve the efficiency of future investment in distributed energy resources. Highly concentrated peak transmission charges could be expected to cause inefficient investment in distributed energy resources, done to avoid the peak transmission charges. Economic agents invest in

Comment [EW88]: What energy price – wholesale or retail. If wholesale, is the assumption a 1:1 pass-through to retail?

Comment [EW89]: What low cost generation has been displaced by higher cost generation as a consequence of transmission charges since the introduction of the wholesale market? In my experience an inability to capture location differences is a much bigger issue.

Comment [EW90]: See previous comment – with an average locational difference of say 12.5% between Benmore and Otahuhu there has to be a significantly more efficient plant proposed in the South Island to be constructed ahead of an equivalent plant in the North Island.

distributed energy resources that are cheaper than peak electricity prices, inclusive of transmission charges, but which are more expensive than peak electricity prices, exclusive of transmission charges.

8.97 The extent of any such inefficiency depends critically on the relative cost of new technologies. Our assessment suggests that, over the next 20 years, the cost of new technologies is likely to cause a large amount of inefficient investment in distributed energy resources that cost more than peak electricity prices exclusive of transmission charges.

8.98 This assessment is based on the gains from investing in network scale batteries in order to arbitrage peak electricity prices, inclusive of transmission charges. Storage technologies are the most relevant technologies for our assessment as other technologies are either already economic, under limited circumstances (such as distributed wind generation), or do not affect peak charges unless storage costs are considered (such as in the case of solar generation).

8.99 We assume in our main scenario that the levelised (through life) capital costs of batteries is $250/MWh[74] in 2019 and that this cost declines at 7 percent per annum over the next 30 years.[75] Under a regime of peak transmission charges, investors can purchase electricity off-peak and sell the electricity into the wholesale market during peak and shoulder periods while also avoiding transmission charges.

8.100 Under our assumptions about distributed energy resources and their cost, transmission charges under the current TPM arrangements cause $564 million of investment in distributed energy resources to be brought forward, inefficiently, between 2027 and 2042. In present value terms this equates to a cost of $2[illegible]6 million.

8.101 This also increases transmission prices, because Transpower's revenue is recovered over a smaller volume of electricity. This leads to a cost to consumers of $19 million (present value, over and above the allocative efficiency costs of the current TPM of $2,383 as outlined earlier).

8.102 Investment in batteries to avoid peak demand charges would have the effect of reducing the need for transmission investment. However, this reduction in costs is inefficient in so far as it results in net costs to consumers through higher transmission charges and inefficient investment in batteries.

8.103 When we factor major transmission capital expenditure into our main scenario (see the discussion below), the TPM proposal delivers a benefit of $183 million (present value) from avoiding battery investment inefficiently brought forward under the current TPM arrangements.

8.104 It should be noted these results only consider the incentive investors would have to invest in network scale batteries solely for the purpose of arbitraging energy costs and avoiding peak transmission charges.

Comment [EW91]: Two issues, this flies in the face of almost all international experience. DG is more efficient than the alternatives. A 100MW solar, wind or other new technology plant located at the point of consumption must by definition be more efficient than the same plant located remotely from the load. This assessment must be backed up by evidence.

Comment [EW92]: The primary revenue streams from storage do not relate to energy arbitrage. See the Horncastle Power Reserve plant (Tesla battery in South Australia) for details. My experience with similar plant in Australia highlights that they expect to get the majority of revenue from similar schemes.

Comment [EW93]: Current prices are probably circa NZ$160. A recent Stanford University study has found that storage prices have dropped by approx. 75% since 2012, and significant future declines are expected.

Comment [EW94]: Solely relying on arbitrage opportunities is not the basis for storage investment. See previous comments

74 This value is potentially high for batteries used to avoid transmission charges. Our analysis suggests that current levelized cost of batteries, used to avoid coincident peak transmission charges, may be as low as $190/MWh. The value of $250 per MWh is for batteries used to arbitrage between lower priced off-peak energy and higher priced peak and shoulder energy.

75 Bloomberg New Energy Outlook 2018 projects battery costs to decline by 66 percent over 13 years (an average annual decline of approximately 8 percent per year). We have adopted a lower annual average decline for our main scenario, in order to not overstate impacts. We have used the higher 8% average annual decline as a sensitivity for relatively lower future distributed generation costs.

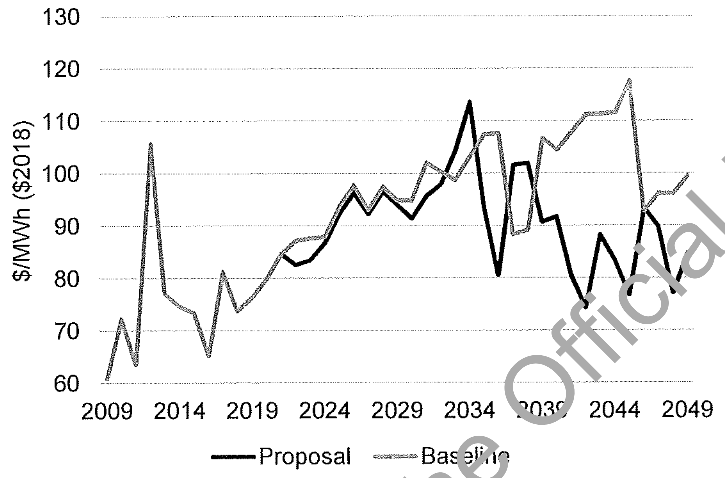
Notes: 1. $2018 millions

8.106 In the baseline, energy prices are substantially higher, on average, than under the proposal (see Figure 6). This is because rising interconnection (peak demand) charges suppress growth in demand, reducing demand for generation capacity and opportunities for profitable investment in electricity generation. This has the effect of lengthening generation investment cycles, so that prices are higher for longer.

Comment [EW95]: Growth in peak demand. Need to be careful about what we are talking about - are we considering energy (MWhs) or capacity (MWs)?

Figure 7: Average energy prices exclusive of interconnection charges

Annual average



Source: Electricity Authority

Notes: 1. $2010

8.107 In this fourth and final step of our modelling, we include in our modelling all potential major capital expenditure included in Transpower's RCP3 proposal (for commissioning in RCP3 and beyond). This includes:

(a) Waikato and Upper North Island voltage management

(b) South Island reliability — HVDC 2 replacement cables and 1 new cable

(c) Upper South Island voltage stability — switching station at Rangitata

(d) Upper South Island voltage stability — new line Islington

(e) South Island reliability — lower South Island (Clutha – Upper Waitaki)

Comment [EW96]: Which of these projects have been deferred due to maximum demand price signals? If these have to be brought forward due to increasing peak demand from removing that signal then then there is welfare loss - has this ben captured?

8.108 We have allocated the benefits of these major transmission investments based on LCE shares. This enables us to compare the effects on consumer welfare of:

(a) these major transmission investments, and

(b) changes in demand on investment in grid-connected generation and energy costs.

8.109 We are evaluating the impacts of allocating transmission charges based on the benefits of increased capital spending across the entire interconnected network, rather than evaluating the impacts of allocating transmission charges based on the benefits of specific transmission projects.

8.110 Under this final step, and as for the preceding steps in our analysis, we have assessed the impact that demand growth could have on bringing forward transmission investment and increasing costs on consumers.

8.111 As discussed above, we assume that revenue per maximum observed peak MWh is maintained in the face of increased peak demand. Assessing any consequent increase in transmission investment costs is complicated by the presence of reduced peak grid demand in the baseline due to investment in batteries to avoid peak demand charges and rising interconnection charges, per MWh of peak demand and thus lower peak demand. The effect of this dynamic on peak prices for grid delivered electricity is summarised in Figure 7.

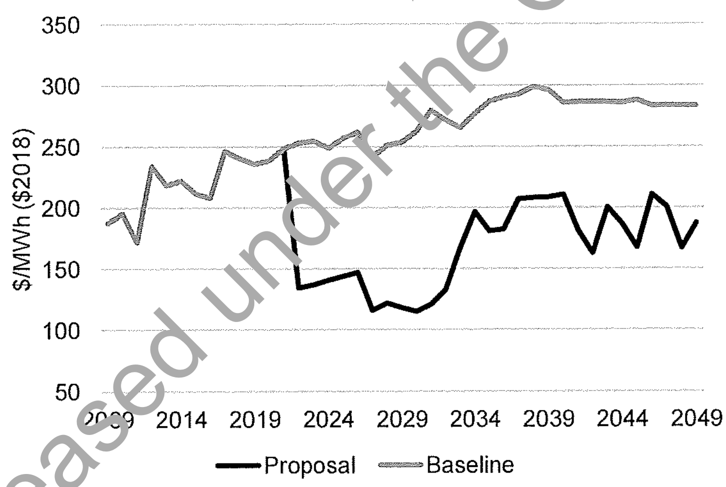
8.112 We would expect that transmission investment would decline in the baseline as demand for transmission capacity declines with the decline in peak demand. Nonetheless, for simplicity, we maintain the assumption that transmission investment proceeds at a pace necessary to ensure constant revenue per maximum observed peak MWh. This assumption reflects the fact that a majority of interconnection revenue is related to past investments and is unaffected by reduced demand for transmission services when there is a reduction in peak demand.

Comment [EW97]: Only as it relates to growth projects. Sustaining and reliability projects would arguably remain the same.

Figure 8: Peak demand prices inclusive of interconnection charges

Comment [EW98]: Wholesale or retail prices? Does the proposal curve include the average transmission component or has transmission been totally excluded, while there may be no peak price component there must be some transmission component?

Annual average



Source: Electricity Authority
Notes: 2. $2010

8.113 A summary of the costs and benefits of the proposal are summarised in Table 38. The first row is our assessment of gross allocative efficiency gains – the amount that consumers would be willing to pay for the proposed TPM inclusive of costs from revenue transfers between generators and consumers ((E) in Table 38).

(a) greater consumer engagement in transmission investment decisions, and

(b) improved efficiency of transmission investment due to improvements in the incentive compatibility of transmission pricing under the TPM proposal relative to under the current TPM arrangements.

Comment [EW99]: Can these benefits be claimed when Transpower was previously subject to the GIT and is currently subject to the Capex IM? Both of these tests were aimed to address the issue of potential information asymmetry between Transpower and market participants to ensure new investments were efficient.

We have considered the undergrounding of transmission assets in Auckland

8.118 Under the current TPM arrangements, the cost to consumers in Auckland of an undergrounding investment would be substantially lower than the cost of the investment. This is shown in Table 40.

8.119 Under the current TPM arrangements, mass market prices (average per MWh) in Auckland (represented by the Otahuhu backbone node) rise by less than mass market prices in Hawke's Bay (represented by the Redcliffe backbone node) or Wellington (the Haywards backbone node). This reflects the fact that the Auckland undergrounding investment is paid for by consumers based on shares of coincident peak demand, even though those volumes are unrelated to the drivers for the investment.

Table 40: Impact of Auckland undergrounding on wholesale prices

Change in prices, average 2030-2049, inclusive of interconnection charges

Island		Current TPM arrangements		TPM proposal	
	Backbone node	Mass market	Large industrial	Mass market	Large industrial
North	MDN	7.3	--	-1.2	--
	OTA	8.3	6.4	5.4	4.3
	HLY	8.0	3.1	-1.2	-0.8
	TRK	8.2	5.7	-1.3	-0.7
	WKM	-0.2	--	-0.6	--
	SFD	8.1	0.6	-1.2	-1.0
	RDF	9.1	0.3	-1.3	-0.8
	PPE	8.7	3.1	-1.3	-1.0
	HAY	9.3	--	-1.4	--
South	KIK	8.7	--	-1.4	--
	ISL	8.1	9.1	-1.3	-1.2
	BEN	9.0	--	-1.2	--
	ROX	10.0	--	-1.3	--
	TWI	9.1	-2.9	-1.2	-1.0

Source: Electricity Authority

Notes: 1. $2018 per MWh

8.120 This Auckland undergrounding scenario is based on an investment of $1.5 billion in total, commissioned over a period of 10 years in equal amounts, adding $25.5 million to Transpower's required revenue in each year that a new tranche of work is completed.

8.121 We assume this transmission investment is inefficient (the costs exceed benefits), but that the investment is mandated by Auckland regional planning requirements. We assume there is enough public interest in the project, in Auckland, to justify the investment at a cost to consumers of $3.9 per MWh (a total cost of $999 million in additional transmission charges, between 2030 and 2049). However, this ignores the substantial cost the investment would impose on consumers outside Auckland.

Comment [TS100]: Need to be careful with this assumption. ComCom regime is intended to prevent inefficient investments from taking place.

Perhaps a safer assumption might be that there was a lower-cost (above ground) alternative that was ruled out by Auckland regional planning requirements.

Comment [EW101]: Which lends to the concept of this being a connection asset.

8.122 Under the current TPM arrangements, the cost of such an investment would lead to:

(a) increased electricity prices for all consumers

(b) a decline in electricity consumption for all consumers.

8.123 Under the TPM proposal, price increases are concentrated in Auckland. The TPM proposal substantially increases the welfare gain to electricity consumers by avoiding a significant increase in electricity costs, except in Auckland. The estimated welfare improvement is $987 million – over and above the main result (see **Error! Reference source not found.**, consumer welfare change excluding energy prices).

8.124 In addition to direct welfare costs from increased transmission charges and higher energy prices the undergrounding project causes an additional $27 million (present value) of inefficient investment in batteries to avoid higher transmission charges.

Table 41: Consumer welfare changes: Auckland undergrounding scenario

Comment [EW102]: If the undergrounding is considered an Auckland connection asset then no welfare change, from the proposal.

Present value welfare change 2022-2049, TPM proposal versus current TPM arrangements, incremental effect of undergrounding scenario

Island		Auckland undergrounding	
		Mass market	Large industrial
North	MDN	61	--
	OTA	-185	-45
	HLY	154	4
	TRK	111	6
	WKM	0	--
	SFD	59	0
	RDF	73	-1
	BPE	65	2

Island		Auckland undergrounding	
		Mass market	Large industrial
	HAY	185	--
South	KIK	62	--
	ISL	301	2
	BEN	54	--
	ROX	61	--
	TWI	52	-33
	Sub-total	1,052	-65
	Total	**987**	

Source: Electricity Authority

Notes: 1. $2018 millions

Comment [EW103]: Can someone check why there should be a welfare loss at TWI for large industrial customers.

8.125 Given the concentrated cost impost on consumers in Auckland, it is much more likely that this investment would not go ahead, which would be economically efficient. If the investment were to proceed, the impact would be much less damaging to consumer welfare than under the current TPM arrangements.

8.126 Even if such an investment proposal was rejected under the current TPM arrangements, following analysis and consultation on the investment proposal's costs and benefits, the cost of analysis and consultation would be inefficient. This is because it could have been avoided under the TPM proposal, by applying the AoB charging methodology to the proposed investment.

We have considered the proposed WUNI voltage stability project

8.127 The purpose of the WUNI voltage stability project is to resolve voltage stability issues in the upper North Island. As with the Auckland undergrounding scenario, the WUNI voltage stability scenario shows consumer welfare gains from allocating transmission costs to areas of benefit, rather than passing the costs on to all consumers.

Comment [EW104]: But arguably this provides a reliability benefit that provides wider benefits than solely to the upper North Island.

8.128 Under the current TPM arrangements, the cost of the WUNI voltage stability project would be imposed on all consumers. Under the TPM proposal, we assume the costs of the WUNI voltage stability project would instead be imposed only on consumers supplied by the Otahuhu and Marsden backbone nodes.

8.129 As shown in Table 42, in the WUNI voltage stability scenario, the TPM proposal delivers $131 million in additional consumer welfare compared with the current TPM arrangements. The underlying drivers for most of this benefit are the same as for our main (Mixed renewables) scenario.

8.130 The major capital expenditure modelled in this WUNI voltage stability scenario is limited to $171 million in transmission assets commissioned (in two steps) in 2030 and 2031. We expect Transpower will invest a more modest amount of resources before 2030 to manage voltage issues in the upper North Island. However, we have not considered this

(b) higher energy costs — caused by a delay in new generation investment relative to generation investment under the TPM proposal, with this delay being due to lower peak electricity demand because of the RCPD charge.

8.132 Under the TPM proposal there will be substantially less (if not zero) incentive on consumers who are not beneficiaries of the WUNI voltage stability project to oppose the project. Under the current TPM arrangements, consumers outside Auckland and Northland would have a material incentive to scrutinise and oppose the investment, because:

(a) there would be no benefits to them from the project

(b) they would face substantial costs — for example:

(i) $25 million to large industrial consumers, including $17 million to large industrial consumers supplied at the Tiwai backbone node

(ii) $51 million to mass market consumers supplied by the Islington backbone node.

8.133 Under the TPM proposal, there would be an increased incentive on consumers in Auckland and Northland to scrutinise the proposed WUNI voltage stability project, and to try to determine if Transpower's proposal is the most cost-effective option available. Furthermore, those consumers in Auckland and Northland with alternatives to the proposed investment could provide Transpower with information to show that they would be unlikely to benefit from it. They may, for example, have a local generation alternative that could ultimately reduce the costs of the proposed voltage stability project. Such incentives are much more muted under the current TPM arrangements.

Comment [EW105]: Under the current Capex IM Transpower is required to identify and consider a range of alternatives. If this is the case is there any benefit?

8.134 Under the TPM proposal there would be a lower probability of delay caused by non-beneficiaries trying to prevent the WUNI voltage stability investment altogether. Although some beneficiaries may resist being identified as beneficiaries, they will have an incentive not to delay the investment, as doing so would mean they possibly faced substantial costs from reduced service reliability.

Comment [EW106]: Prudent project management will build in requirements for consultation into the timetable. Therefore there shouldn't be a delay but rather an earlier start date for developing the business case for submission to ComCom.

8.135 If the WUNI investment is efficient, with a benefit-to-cost ratio of at least one, any unnecessary delay to the project would create costs for consumers.

8.136 Recent history shows that misalignment of transmission charges from benefits of transmission investment benefits causes avoidable costs to consumers. The Otahuhu substation diversity project, approved by the Electricity Commission in August 2007, was challenged by major electricity users. This challenge began as part of the Electricity Commission's approval process and continued through the High Court and the Supreme court. Though the challenge was ultimately unsuccessful, it carried costs in terms of project delays and litigation costs.

8.137 This challenge was motivated, in part, by the prospect of significant increases in transmission charges for major users that did not stand to benefit from the project. The New Zealand Aluminium smelter, for example, faced an increase in charges of approximately $1.5 million per year.

8.138 Assuming that the project was efficient and beneficial to consumers in Auckland, the costs of this challenge are estimated to be $3.1 million. This is based on procedural and litigation costs of $1.5 million and costs to consumers of $1.6 million in reduced energy

Comment [TS107]: Need to say something about the fact that we are assuming the opposite (in deciding that Otahuhu costs will be recovered through the residual charge)

8.139 Extrapolating the costs of delay and judicial proceedings to future investments, the potential future cost of similar challenges, caused by the current transmission pricing arrangements is estimated to be a present value \$1.7 million.[77]

8.140 Notably, the estimated cost of delay, in terms of reduced reliability, is much lower than the incremental cost of the substation diversity project. The approved cost of the project, \$125.6 million (2018 dollars), implies a break-even economic annual benefit that is 10 times larger than the annualised benefits of the investment.

8.141 This raises the prospect of whether this, or other investments, might have been efficiently delayed or cheaper alternatives employed to meet the same objectives if beneficiaries of these investments had faced the costs of these investments.

Comment [EW108]: Isn't this moot – the projects were approved by the regulator.

8.142 The Upper North Island Dynamic Reactive Support (UNI DRS) is example of another investment that may have differed if beneficiaries faced the costs of this project. The UNI DRS project, proposed to the Electricity Commission in 2010, assumed that there would be "no new committed generation in the Upper North Island region prior to 2015".[78] Yet there was the potential for new generation, as has become apparent with the forthcoming expansion of the Ngawha geothermal power plant. This is not to say that the expansion of Ngawha would necessarily have reduced the need for increased dynamic reactive support in, say, Northland (one component of the project). However, there was no incentive on Ngawha's owners or on the beneficiaries of the project to consider if there were cheaper alternatives that could, efficiently, delay the costs – including whether costs could be efficiently deferred by funding (in part) the expansion of Ngawha.

Comment [EW109]: It is requirement of the regulatory process for Transpower to consider alternatives – they would undoubtedly have consulted with parties with alternatives..

8.143 Indeed, of the \$2.2 billion of reliability investments approved by the Electricity Commission between 2005 and 2011, 90% (\$1.9 billion) was to support reliability of supply in the Upper North Island. However, consumers in the Upper North Island were only likely to face around one-third of this cost. As such, the incentive to submit alternative, cost-saving, investments, was also only one-third the size of what it might have been.

Comment [EW110]: Need to think about how this is worded, this may come across as a veiled criticism of the efficiency of the investments and Transpower. The reality is they were approved by the regulator.

Comment [EW111]: This does not reflect the process taken. A large number of potential alternatives were considered with a subset of these subjected to detailed analysis.

8.144 While the current TPM did and does provide incentives to non-beneficiaries to scrutinise transmission investment proposals, the size of these incentives are small (diffuse) and do not offer sufficient private benefits to motivate the provision of cost-effective alternatives to transmission investment. Although the current TPM does provide incentives on participants to challenge investment proposals, as the example of the Otahuhu substation project shows, it does not necessarily provide sufficient incentives for constructive engagement and identification of efficient alternatives.

Comment [EW112]: The TPM might not but the Capex IM certainly does.

8.145 In addition to insufficient incentives to identify alternatives, the beneficiaries of projects are also not incentivised, proportionate to the cost of investments, to scrutinise assumptions that underlie investment decisions – such as demand forecasts.

Comment [EW113]: This was not the experience.

8.146 We note that in other contexts the increased participation of consumers in regulatory decision making processes leads to:

[77] Based on the cost of the Otahuhu substation challenge costing 0.15% of expenditure approved between 2005 and 2011 and assuming the same potential cost as a proportion of major capex forecast between 2022 and 2049.

[78] Electricity Commission, July 2010, Reasons for Decision set out in Notice of Intention to Approve Transpower's Upper North Island Dynamic Reactive Support Investment Proposal.

(a) lower transactions costs and faster speeds of regulatory decision making (Chakravorty, 2015)[79]

(b) lower prices through lower regulated returns (Fremeth et al, 2014)[80]

(c) lower costs of accessing information and lower costs to consumers associated with regulatory decisions (Fremeth and Holburn, 2012).[81]

Comment [EW114]: These findings are likely specific to the regulatory models applied in the jurisdictions considered. As such they may not be generalisable to NZ. For example, my experience with regulatory approval for transmission in NZ and North America highlight significant differences between the two regions.

8.147 The proposal clearly increases incentives of interested parties (and confines these incentives to parties with an interest in the economic efficiency of investments).

We assess the proposal to have advantages in terms of durability

8.148 The proposal has benefits of being more durable than the alternative or current TPM arrangements.

Comment [EW115]: Any TPM is subject to change – it cannot be claimed that the proposed option will be any more durable than previous ones. There is considerable effort going into identifying new alternatives for transmission pricing given the impact technology change is having.

8.149 For the purposes of this CBA we define durability as the degree to which a policy is likely to be subject to successful challenge and change or reversal, whether on grounds of inefficiency or unreasonableness.

8.150 The proposed TPM is more efficient than current arrangements in terms of allocative efficiency and dynamic efficiency, in so far as current arrangements have higher costs in terms of generation investment distortions and promote investment solely for the purpose of avoiding the costs of past investments.

8.151 The alternative has similar efficiency attributes to the proposal but does not provide the additional efficiency benefits of reducing the likelihood of investments that are inefficient, as outlined in the undergrounding scenario shown earlier.

8.152 The proposed TPM is much less likely to be challenged on grounds of reasonableness, as transmission charges are allocated to beneficiaries. The key test for reasonableness, in this context is whether consumers are expected to pay for the costs of services that they do not benefit from.

8.153 The less durable a policy, the more likely it is to be overturned and the greater is uncertainty about the future.

8.154 Uncertainty is costly where investment is concerned, raising risk premia and capital costs and delaying investment. This is especially so for investments in plant and equipment that have no significant alternative uses, such as is often the case in electricity. For example, a business that is considering investing in an electric boiler will take account of current and future costs of electricity including transmission costs when deciding whether to invest. The potential for future costs to increase due to investments that do not reduce the price of energy or provide other benefits (reliability of supply) will reduce the attractiveness of the investment.

8.155 There are good reasons to believe that minimising uncertainty is of particular importance in the current environment and in coming years. The electricity industry is facing the prospect of significant change with:

[79] Chakravorty, S. (2015). A study of the negotiated-settlement practice in regulation: Some evidence from Florida. Utilities Policy, 32, 12–18

[80] Fremeth, A. R., Holburn, G. L. F., & Spiller, P. T. (2014). The impact of consumer advocates on regulatory policy in the electric utility sector. Public Choice, 161(1–2), 157–181.

[81] Fremeth, A. R., & Holburn, G. L. F. (2012). Information Asymmetries and Regulatory Decision Costs: An Analysis of U.S. Electric Utility Rate Changes 1980–2000. The Journal of Law, Economics, and Organization, 28(1), 127–162.

(a) falling costs of alternative, renewable and distributed energy resources

(b) increased penetration of ICT and of equipment and business models that facilitate increased consumer participation in the electricity industry

(c) potentially large increases in electricity demand as a result of increased electrification to meet climate change mitigation objectives including:

 (i) increased penetration of electric vehicles

 (ii) increased electrification of industrial energy demand.

8.156 Thus it is important that policy, including in relation to transmission pricing, does not enhance uncertainty but rather supports efficient investment to take place.

8.157 It is difficult to quantify the effects of increased durability – i.e. reduced uncertainty – on investment as the effects of uncertainty are likely to be context specific and future conditions for investment are not known. Furthermore, there is no relevant research in New Zealand for us to draw upon that is directly related to transmission pricing on investment in the New Zealand electricity industry.

8.158 We do observe research from the United States that quantifies, empirically, links between policy uncertainty, reversals and reduced investment.

(a) Fabrizio (2013) found that in the United States policies aimed at increasing investment in renewable electricity generation (Renewable Portfolio Standards) had no effect in states that had reversed earlier measures to restructure the electricity industry.[82] States with more stable policy environments experienced an increase in investment in renewable electricity generation.

(b) Ford (2018) found that a reversal of regulatory settings in the telecommunications industry in the United States in the 2010s – raising the prospect of increased regulatory controls – caused a 20% decline in investment in internet services.[83]

(c) Gulen and Ion (2016) use an index of policy uncertainty throughout the economy to estimate effects of uncertainty on economywide investment and find that "a doubling in the level of policy uncertainty is associated with an average decrease in quarterly investment rates of approximately 8.7% relative to the average investment rate in the sample" (p.525).[84] They also find that the dampening effect of uncertainty on investment is highest in industries where investments are typically irreversible.

Comment [EW116]: Is this US specific and therefore not applicable to NZ – for example to what extent are changes in RPS due to instability in government – it is not the policy that is the problem but the ideological position of government and people appointed to them, such as regulators. Similarly how much of the decline in internet services investment related to the dark fibre overhang?

8.159 These findings are supported locally by researchers at the Reserve Bank of New Zealand who find a negative relationship between uncertainty and macroeconomic measures of economic activity including investment.[85]

8.160 Qualitatively, this shows that improved durability is an important benefit of the proposal.

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[82] Fabrizio, K. R. (2013). The Effect of Regulatory Uncertainty on Investment: Evidence from Renewable Energy Generation. The Journal of Law, Economics, and Organization, 29(4), 765–798.

[83] Ford, G. S. (2018). Regulation and investment in the U.S. telecommunications industry. Applied Economics, 50(56), 6073–6084.

[84] Gulen, H., & Ion, M. (2016). Policy Uncertainty and Corporate Investment. The Review of Financial Studies, 29(3), 523–564. https://doi.org/10.1093/rfs/hhv050

[85] https://www.rbnz.govt.nz/-/media/ReserveBank/Files/Publications/Analytical%20notes/2018/an2018-01.pdf?revision=7377a00f-a898-43d4-b1b2-5dbff8005bdb

Island		Including energy price effects		Excluding energy price effects	
		Mass market	Large industrial	Mass market	Large industrial
	Total	-1,164		-556	

Source: Electricity Authority
Notes: 1. $2018 millions

Extensions to the prudent discount policy offer modest welfare improvements

8.164 The proposed extension to the prudent discount policy has two key elements:

(a) to extend access to a prudent discount to consumers that would disconnect from the grid in favour of alternative supply

(b) to allow for a prudent discount to be agreed for the life of a transmission asset to which the prudent discount applies (in contrast to the current maximum time limit of 15 years).

8.165 The proposed extension of the prudent discount policy is expected to promote benefits to consumers by allowing for the costs of transmission investments to be spread as broadly as possible over the beneficiaries of transmission assets.

8.166 The prudent discount policy allows for a reduction in a DTC's interconnection charges if the DTC can show they would disconnect from the grid, resulting in costs being shifted to other consumers.

8.167 The cost to consumers from a transmission customer disconnecting from the grid is estimated to be a maximum of $132,701 per MW of load disconnected (2018 dollars). This is based on:

(a) average interconnection revenue of $132,698 per MW between 2022 and 2049

(b) assuming a flat load profile (i.e. 1 MW equalling 8,760 MWh of demand)

(c) costs being reallocated under the TPM proposal to all remaining demand in proportion to estimated transmission charges

(d) using the demand model described in [XX] to assess the welfare consequences of consumers facing an increase in charges to recover the revenue no longer paid by the disconnecting DTC.

8.168 The average increase in transmission charges for a 1 MW disconnection would be 0.02 percent. The cost to consumers is the compensation required to ensure consumers are no worse off following the increase in transmission charges. This amount, $132,701, is fractionally higher than the amount of revenue that is reallocated to DTCs.

Comment [EW118]: 0.02% or 2%

8.169 The proposed extension of the prudent discount policy to include cases of disconnection in favour of alternative supply (generation), would increase the likelihood that consumers could avoid the cost of increased transmission charges (via a prudent discount). There are currently no clear examples of situations where this extension may be applied.