CBA approach, methods and assumptions

Proposed TPM 2021

Technical paper

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1 Our overall approach to the Cost Benefit Analysis (CBA)

1.1 The purpose of this paper is to set out:

(a) the approach the Authority has followed in quantifying the proposal's costs and benefits

(b) the main models we have used in the CBA to quantify costs and benefits

(c) the main assumptions we have made when quantifying costs and benefits.

The CBA framework and methods follow those used for the TPM Guidelines CBA

1.2 The CBA framework and methods for the assessment of the costs and benefits of the proposed TPM are very similar to those used in the Authority's analysis of the TPM Guidelines in 2020 (the Guidelines CBA). The underlying CBA methodology was thoroughly reviewed and tested during the 2020 Guidelines process, changes have been made to address feedback, and the Authority is comfortable that any issues raised have been properly addressed.

1.3 The CBA presented here does include some significant changes in input assumptions to reflect information which has become available since the Authority's decision on the Guidelines, as well as changes in order to reflect design detail of the proposed TPM put forward in this paper. The Guidelines CBA had to make various assumptions in modelling a new TPM, since the detailed design of the proposed TPM had yet to be developed.

CBA as an aid to decision-making

1.4 The CBA for the proposed TPM is an aid to support deliberation and decision-making, alongside a broader range of factors the Authority has to consider. The quantitative component of the CBA gives a sense of the order of magnitude of the quantifiable benefits and costs. These impacts sit alongside effects that cannot reasonably be quantified, and which are not discussed in this technical paper, but which are also relevant and are being considered by the Authority.

1.5 A CBA cannot be a precise exercise. There is imperfect knowledge about the current electricity system, and there are always uncertainties about how the future will unfold. Modelling by its nature seeks to provide a tractable representation (and not a replica) of a complex system. There will always be different views about assumptions made, approaches that could have been taken, and opportunities to refine the analysis.

Aspects of the CBA's design and methodology are novel

1.6 Aspects of the design and methodology of the CBA are novel. This is because the nature of the proposal is novel in a New Zealand context—specifically, the focus on calculating benefits for the purpose of setting transmission charges.

The CBA uses bespoke models as part of a primarily 'bottom up' approach

1.7 To improve the quantitative analysis of the proposal's more novel aspects, we have used bespoke models in the CBA, primarily for our assessment of more efficient grid use and more efficient investment in utility-scale batteries. These bespoke models form part of a primarily 'bottom up' approach to articulating and analysing the mechanisms by which the proposal would lead to incremental gains in economic efficiency. We refer to these bespoke models collectively as the grid use model.

1.8 This document is intended to provide signposts and explanations for the construction and operation of the grid use model. The grid use model files, released alongside this document, are a supplement to this document and provide more extensive and highly detailed information about the grid use modelling.

The CBA also uses some 'top down' analysis

1.9 The CBA uses a 'top down' approach to assess quantifiable long-term effects of the proposal on investment by electricity suppliers (generation and transmission) and consumers, scrutiny of grid investment proposals and increased certainty for investment.

The CBA largely follows the approach in the CBA working paper

1.10 The CBA continues to largely follow the general approach set out in our 2013 CBA working paper.[1]

Table 1: High-level approach to CBA

Step	Synopsis
Define the problem	Established in chapter 2 of the 2020 Decision Paper—e.g., • poor price signals that result in inefficient consumption and investment • current TPM not durable, resulting in inefficient operation of electricity industry
Select options for addressing the problem that will be assessed	• Proposed TPM: o removal of HVDC and RCPD charges o benefit-based charges, using a simple and standard method for allocating costs of future investments (and Schedule 1 for seven historical investments) o residual charge for remaining costs • Variants/options: o recover overhead operating expenditure in residual charges o review of the simple method, five years after the introduction of the proposed TPM, leads to a revision in generators' default share of benefits under the simple method to 25% (75% of benefits attributed to load) o generators' default share of benefits under the simple method is set at 25% (75% of benefits attributed to load) from the commencement of any new TPM. The 2020 Decision paper already considered the benefits and costs of a substantial range of alternative approaches to transmission pricing – including through a quantitative CBA for a subset of options. The Authority does not repeat that analysis and instead the focus is on options available under the Guidelines.
Specify the baseline to measure costs and benefits against	• Current TPM: o HVDC charge on South Island generation o RCPD charge on load.

1 Available at https://www.ea.govt.nz/dmsdocument/15683-working-paper-transmission-pricing-methodology-cba.

Step	Synopsis
	Expected growth in: • demand • costs of utility-scale batteries • generation costs • transmission investment • grid-connected generation • grid-connected load investment
Identify the effects of the proposed options to address the problem	A ‘bottom-up’ approach to analyse whether the proposed TPM leads to incremental gains in economic efficiency, supplemented by ‘top-down’ analysis
Assess the effects of the proposed options[2]	Assess relative effects of pricing options on: • grid use o based on changes to supply costs and prices o accounting for interaction between revenue requirements, prices and electricity consumption • investment in demand-side and supply-side assets, including transmission assets o accounting for differences in timing of options • TPM design, implementation and operation costs
Evaluate against decision criteria	Extent to which the proposed options promote the Authority’s statutory objective, as detailed in the consultation document on the proposed TPM
Test the sensitivity of the results	Testing the robustness of the results to changes in key assumptions
Document the CBA	Set out the above steps in a clear, concise manner

Source: Electricity Authority

2 This step combines steps 5, 6 and 7 of the 10-step process set out in our 2013 CBA working paper.

Scope of our assessment

We have assessed the key features of the proposed TPM

1.11 The CBA assesses the costs and benefits of the proposal to introduce benefit-based and residual charges and remove the HVDC and RCPD charges. It also considers the effects of variations in the calculation of benefit-based charges:

(a) variations in generators' shares of benefits under the proposed simple method for allocating benefit-based charges

(b) impacts of recovering overhead operating expenditure through benefit-based charges or through residual charges.

We have considered changes in electricity costs, investment and demand

1.12 The CBA, particularly the grid use model, considers changes in electricity costs (prices), investment and demand when a new TPM is introduced. The modelling attempts to hold as many things constant as is reasonable, across assessments of costs and demand under:

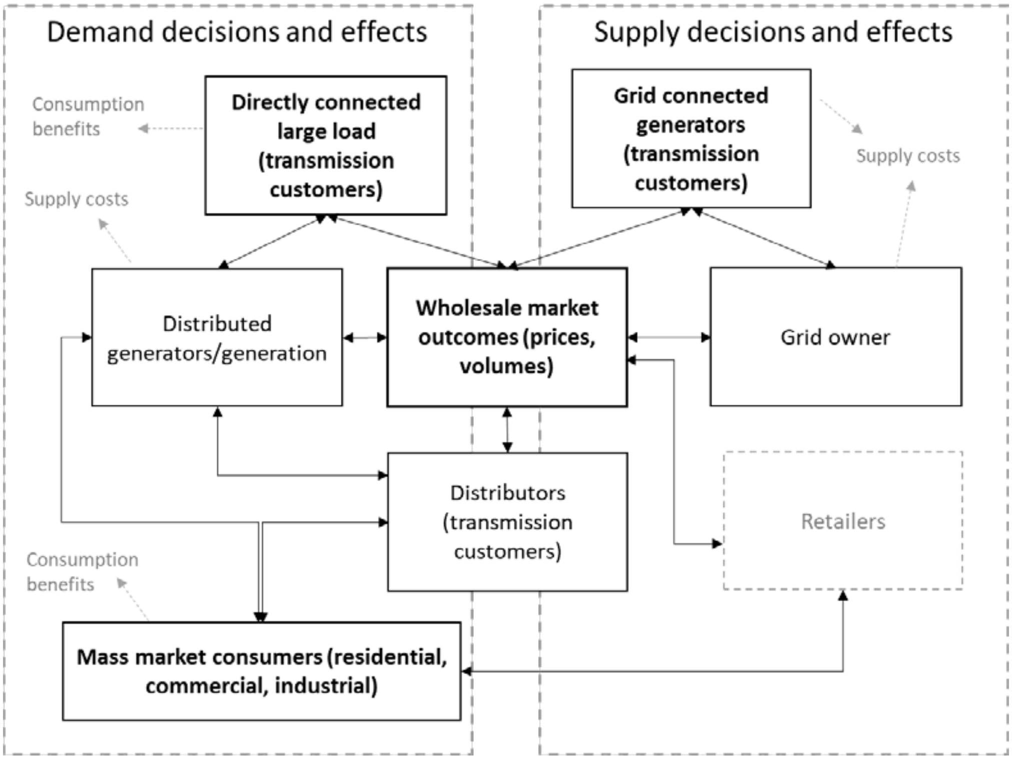
(a) the current TPM (the baseline)

(b) the proposed TPM

1.13 Electricity costs and demand are projected for the period 2021 to 2049, for the baseline and for the three TPM design options listed in Table 1. Then results for these design options are compared and consumer welfare changes or cost differences are calculated.

1.14 Figure 1 summarises the scope of our assessment.

Figure 1: Scope of assessment – affected parties



Source: Electricity Authority

We have focussed primarily on those who pay for transmission assets

1.15 Our primary focus is on those that pay for transmission assets—being:

(a) consumers connected to distribution networks or to the transmission network

(b) grid-connected generators.

1.16 Another focus is on distributors, distributed generators, and the grid owner. These parties make operational and investment decisions, either directly or indirectly, in response to the decisions of the parties paying for transmission assets.

1.17 Central to the CBA (in particular, the grid use model) are wholesale market outcomes, such as prices and consumption. We have focussed on wholesale market outcomes because the core economic value of transmission assets stems from the gains from trade reflected in wholesale market outcomes. Transmission enables consumers to access lower cost energy, and generators to receive higher prices, than they otherwise might.

1.18 Our assessment does not directly consider economic effects on retailers or effects on retail prices. The analysis assumes:

(a) wholesale market outcomes, over time, reflect decisions by both retail consumers and wholesale market participants

(b) changes in retailers' transmission-related costs will, over time, be reflected in retail prices.

We have used quantitative analysis as much as practicable

1.19 To the extent practicable, the CBA uses quantitative analysis to assess the proposed TPM's costs and benefits. Table 3 summarises the impacts we have sought to quantify as part of the CBA.

Note, in the quantitative analysis the transitional cap on transmission charges is categorised as a cost—efficiency costs arise from the transitional redistribution—even though following our qualitative assessment that takes into account durability and certainty during the transitional period we consider it to have a net benefit.

Table 2: Components of the proposal that the CBA assesses quantitatively

Benefit categories	Description
More efficient grid use	An efficient increase in the use of electricity accounting for the relative value to consumers of electricity by time of use.
More efficient investment in distributed energy resources	Reductions in inefficient investment in distributed energy resources (e.g., batteries) for the main purpose of avoiding transmission interconnection charges.
Grid investment benefits brought forward	Grid constraints and losses reduced sooner due to transmission investment occurring earlier than it would otherwise to cater for increases in peak demand.
More efficient investment by generators and large consumers	More efficient investment by generators and large consumers (as they will take account of the costs of all required grid upgrades when making location decisions).
More efficient grid investment—scrutiny of investment proposals	More efficient grid investment (due to greater scrutiny, and less lobbying for inefficient investments).

Increased certainty for investors	Increased certainty for investors reduces the required return on investment.

Cost categories	Description
TPM development and approval costs	Costs such as policy analysis, modelling and legal fees.
TPM implementation costs	Costs of computer hardware and software, development and testing, changes to business processes, policies and procedures, and user training.
TPM operational costs	Costs of data gathering and management, invoicing and customer liaison.
Grid investment costs brought forward	Requirement for transmission investment to occur earlier than it would otherwise to cater for increases in peak demand.
Load not locating in regions with recent investment in capacity	Distortion from large energy-intensive consumers avoiding investing/locating in a region that already has a benefit-based charge.
Transitional cap on transmission charges	Suppressed demand of customers with transmission charges that are *not* capped.

Source: Electricity Authority

1.21 We have been careful to not double count any benefits and costs that occur for more than one component of the proposal, but which are not additive in nature. That is, we have counted a benefit/cost only once when it occurs for two or more components of the proposal.

Relevant markets and boundaries for the analysis

1.22 The CBA focuses on the extent to which the proposal promotes the Authority's statutory objective, being the extent to which the proposal promotes competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

1.23 The boundaries for the CBA, in terms of costs and benefits assessed, are set by the definition of 'consumer' in the Electricity Industry Act 2010 (Act) and with reference to the Authority's statutory objective. The Act defines "consumer" to mean "any person who is supplied, or applies to be supplied, with electricity other than for resupply". We interpret "electricity industry" to include all parties involved in the electricity industry, including consumers, and not just "industry participants" as defined in section 7 of the Act.[3]

1.24 The CBA does not evaluate effects on industries, markets, or policy objectives outside the electricity industry—so-called secondary market effects. Examples of secondary market effects include:

(a) indirect effects of transmission prices on labour market outcomes, such as wages, in industries outside the electricity industry

(b) demand, costs, and prices in other energy markets, such as gas, unless they are directly relevant to the functioning and efficiency of the electricity market and have an effect on the long-term benefit of electricity consumers

3 The Act's definition of "industry participants" includes generators, retailers, distributors, and industry service providers.

(c) health or environmental policy objectives and outcomes, where such outcomes and objectives are primarily within the mandate of organisations other than the Authority.

1.25 The way these effects manifest themselves is primarily a function of the efficiency of these other markets and the effectiveness of public policy, public institutions and regulation. Therefore, excluding these matters from the CBA avoids counting costs or benefits that are beyond the control of the Authority or electricity industry participants.

1.26 Assumptions also need to be made about the relative importance of, or extent of, the proposal's effect on the efficiency of the electricity industry. That is, in practice, the electricity industry's efficiency is affected by a range of institutions and potential regulatory and market failures. This includes the functions, powers and duties of the Commerce Commission in relation to the electricity industry.

1.27 It is standard practice in a CBA to focus, by default, on the regulatory or market failure at hand and to assume that other parts of the industry are functioning well. Under this approach, all estimated costs and benefits are ascribed to the policy change (or policy) under scrutiny—so long as those impacts occur within the boundary of the analysis (in this case the electricity industry and benefits for consumers).

1.28 Lastly, we have been careful to avoid estimates of effects being implausibly ascribed to changes to the TPM guidelines.

Our main scenario is based primarily on the Climate Change Commission's demonstration pathway

1.29 The model baseline is based on three main sources of information:

(a) the Climate Change Commission's (CCC) demonstration pathway in its May 2021 final advice to the Government, used for assumptions regarding:

(i) demand growth

(ii) gas prices

(iii) emissions prices

(iv) Tiwai closure

(v) generation plant decommissioning

(vi) rates of decline in the capital cost of new solar and wind plant

(b) the Ministry of Business Innovation and Employment's (MBIE) 2020 generation cost studies, for assumptions regarding capital and operating costs of new generation plant

(c) Transpower's integrated transmission planning schedules and disclosed expenditure plans, for assumptions regarding future capital and operating expenditure and allowable interconnection revenue.

1.30 Table 2 provides a summary of the main baseline assumptions in the modelling, most of which are taken directly from the CCC (2021).[4] In addition to these assumptions, we assume that no new thermal generation is installed, to reflect the Government's 100% renewables target. As policy levers to achieve that target have not been announced, we have not assumed 100% renewables by 2030.

[4] https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/inaia-tonu-nei-a-low-emissions-future-for-aotearoa/modelling/

1.31 Consistent with the CCC's demonstration pathway, the Tiwai Point aluminium smelter (NZAS) is assumed to close at the end of 2024 and the Huntly Rankine units are expected to be decommissioned at that time. The exogenous rate of demand growth in the baseline is consistent with electricity demand rising from around 40,000 GWh currently to approximately 60,000 GWh in 2049.

1.32 However, an alternative baseline is modelled in which NZAS does not close and the Huntly Rankine units are decommissioned in 2026. The scenario where NZAS does not close includes a lower rate of exogenous demand growth, in order for total demand to remain consistent with CCC modelling. This is so that total demand will reach the same level in 2049 as in the central scenario where NZAS does close – absent any price effects that reduce demand growth. Regardless, assumed baseline demand growth is significant.

Table 3: Baseline assumptions

Assumption	Sample values
Wind generation capital costs (LRMC)	
Range for $ per MWh in 2020 ($2018)	$66.9/MWh - $97.3/MWh
Range for $ per MWh in 2035 ($2018)	$61.8/MWh - $88.5/MWh
Average annual growth	-0.80%
Utility scale solar generation capital costs	
Range for $ per MWh in 2020 ($2018)	$87.2/MWh - $113.4/MWh
Range for $ per MWh in 2035 ($2018)	$59.8/MWh - $76.9/MWh
Average annual growth	-3.00%
Battery energy storage costs, utility scale	
$/kW in 2020 ($2018)	$984/kW
$/kW in 2035 ($2018)	$588/kW
Annual average growth	-3.4%
Step changes in demand	
Tiwai departure	Close end 2024 -5,322 GWh
Gas prices, central scenario	
$/GJ in 2020 ($2018)	$8.50/GJ
$/GJ in 2041 ($2018)	$10.10/GJ
Average annual growth	0.9%
Emissions prices	
$ per tonne 2020 ($2018)	$28.8/t
$ per tonne 2035 ($2018)	$154.3/t
Average annual growth	11.8%
Exogenous demand growth, average % growth	
Total	2.00%
Population growth	0.74%
Income growth	0.14%
Electrification	1.13%
Exogenous construction	
Turitea wind, stage 1	119 MW, by 2022
Turitea wind, stage 2	103 MW, by 2023
Mt Cass wind	93 MW, by 2023
Tauhara geothermal	152 MW, by 2025
Harapaki wind	176 MW, by 2025
Total	643 MW, 2022-2025
Decommissioning	

Huntly gas/coal units (Rankines)	-500 MW end 2024

Source: Electricity Authority

1.33 Baseline transmission revenue is based on Transpower's disclosed expenditure plans between now and 2035, and a bespoke assessment of potential new major capex given assumed high rates of demand growth. Substantial investment is expected between now and 2035, including augmentation of the HVDC. After 2035, capital expenditure is expected to be low for a time with sufficient capacity to accommodate demand growth until another assumed investment cycle 2040-2045.

1.34 Transmission revenue is expected to grow gradually in coming years, reflecting rising capital expenditure. In the baseline (that is, under the current TPM), generation customers' charges are expected to average around 11% of interconnection charges, down from the current 13% share. Generators' shares of charges tend to rise and fall much more than load customers' shares under the current TPM, in line with expenditure on the HVDC.

2 Benefits from more efficient grid use

Factors affecting benefits from more efficient grid use

2.1 In quantifying the proposal's total net benefit from more efficient grid use, under our main scenario,[5] we consider five interrelated effects:

(a) Effect on electricity demand of changes to transmission interconnection charges

(b) Consumer welfare changes due to changes in electricity demand caused by changes in wholesale electricity prices inclusive of transmission interconnection charges

(c) Effects of changes in electricity demand and transmission interconnection charges on investment in grid-connected generation and thereby wholesale energy costs

(d) Effect of changes to transmission interconnection charges on the efficiency of investment in distributed energy resources

(e) Changes in (interconnection) transmission investment costs and benefits.

Effect on electricity demand of changes to transmission interconnection charges

2.2 We used a bespoke model of electricity demand to estimate the responsiveness of distribution-connected consumers and transmission-connected consumers to changes in the price of electricity at grid exit points (GXPs) (i.e., consumers' responsiveness to changes in wholesale electricity prices inclusive of transmission interconnection charges).

2.3 Consumers' responses to changes in wholesale electricity prices inclusive of interconnection charges vary:

(a) between distribution-connected consumers and transmission-connected consumers

(b) between areas of the country.

2.4 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.

2.5 Variations in consumers' responsiveness to wholesale electricity prices inclusive of interconnection charges also reflect:

(a) the availability of local, distributed generation

(b) differences in wholesale energy prices across the transmission network, reflecting the cost of transporting electricity across it.

2.6 Consumers' responsiveness to wholesale electricity prices inclusive of interconnection charges tends to increase if wholesale energy prices are relatively higher. For example, consumers in Northland will tend to be more responsive to wholesale electricity prices inclusive of interconnection charges than consumers in South Canterbury. This is because the wholesale price of energy in Northland is generally higher than the average wholesale energy price nationally, while wholesale energy prices in South Canterbury are on average lower. This price difference reflects the extent to which consumers in Northland rely on more of the transmission network to transport energy to them (thereby facing the cost of more

5 I.e., the updated EDGS 'Mixed renewables' scenario.

energy losses and constraints on this network), compared with consumers in South Canterbury.

2.7 GXPs with a substantial amount of distributed generation can avoid transmission interconnection charges under the current TPM, by reducing their share of demand during peak demand periods.

2.8 For example, Whakamaru has significant distributed generation situated around it, resulting in Whakamaru consumers' electricity offtake from the transmission network being close to zero during periods of peak demand nationally. This reduces overall wholesale energy prices at Whakamaru and tends to reduce the sensitivity of Whakamaru consumers to changes in the price of wholesale electricity inclusive of interconnection charges. A 10% change in wholesale electricity prices inclusive of interconnection charges has a smaller impact if the prices are relatively low to begin with.

2.9 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 electricity consumed during periods of peak demand.

2.10 RCPD charges are targeted at the top 100 coincident peak demand periods in each of the four transmission pricing regions. However, we have modelled the RCPD charge to be a charge levied against average MWh consumption during the 1,600 trading periods with the highest MW demand across New Zealand. This choice is based on a cluster analysis of trading periods by transmission pricing region (see also paragraphs 2.155 - 2.156).

2.11 This more diluted price signal is used 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.

2.12 Our model of electricity demand differentiates between fixed and variable components of transmission interconnection charges under the proposed TPM and the different effects that fixed and variable charges have on costs of consumption:

(a) benefit-based charges for historical investments are fixed and impact consumer expenditure via an income effect but not through a price effect i.e. increasing or decreasing consumption has no effect on a consumers interconnection charges

(b) benefit-based charges for new investments are expected to influence consumption decisions with expected revenue on new investments treated as per MWh charges, but these charges become fixed after investments are commissioned and do not impact consumers consumption decisions

(c) residual charges, while fixed initially based on historical lagged anytime maximum demand, impact consumption decisions because an increase or decrease in MWh consumed impacts residual charges, albeit with a lag. Given a discount rate ($r = 0.06$), the lag structure for updating residual charges, and an assumed rate of decline in the size of residual charges ($\delta = 0.05$), the incremental effect of residual charges on costs of consumption is

$$\Delta R_{it} = R_{it}\Delta x_{it}\sum_{t=4}^{7}\frac{1}{4}\frac{1}{(1+r)^t}(1-\delta)^t = 0.55\ R_{it}\Delta x_{it}$$

Where the present valued expected change in residual charges (ΔR_{it}) is a function of the existing levels of residual charges (R_{it}) and a current period change in demand (Δx_{it}).

2.13 The impact of residual charges on consumption decisions is thus discounted by 45 percent (1- 0.55) to reflect that changes in consumption do not begin to affect charges until the fifth year after the change and do not fully affect charges until the eighth year after, and that during that time the total size of the residual charges will also decline.

2.14 Differentiating between fixed and variable charges is necessary for distinguishing the different effects of BBCs and residual charges and thus to account for trade-offs embedded in the proposed TPM. For example, higher residual charges and lower BBCs may mean lower costs on producers, higher rates of generation investment and lower prices for consumers in the long run. But higher residual charges reduce consumption and can also delay such generation investment.

2.15 These considerations are much more material under the proposed TPM, relative to the Guidelines CBA, given that the proposed TPM envisages potentially substantial increases in generators' transmission charges. Albeit the size of any increase will be contingent on final design decisions such as the balance of benefits from base capex between load and generation, and the extent to which overhead costs should be recovered in benefit-based charges.

Consumer welfare changes

2.16 Impacts on consumer welfare reflect changes in wholesale electricity prices inclusive of interconnection charges.

2.17 Consumer welfare changes under the proposal are a combination of two effects:

(a) a **direct effect** on electricity bills, measured by the quantities consumed prior to implementing the proposal multiplied by price changes under the proposal, (i.e., the extent to which consumers' electricity costs would increase or decrease if consumers did not adjust their consumption)

(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.

2.18 Following a fall in electricity prices, consumers may want to retain their chosen quantity and timing of electricity use from before the price change. This would result in them re-optimising their spending across electricity and the other goods and services they buy. This re-optimisation—the indirect or substitution effect—means their change in economic welfare is different than a direct price change measure might suggest.

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

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

(b) rise following increases in transmission capacity

(c) recover overhead costs that are not affected by changes in demand

(d) do not take account of the transport and congestion cost signal already provided in nodal prices.

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

2.21 The value to consumers of using electricity at peak is illustrated by the fact that approximately 30% of wholesale electricity market expenditure (energy cost) occurs during the 1,600 trading periods with the highest electricity demand, despite these accounting for only 9% of trading periods.

2.22 To estimate benefits to consumers, we consider:

(a) the value to consumers of using electricity during peak demand periods, based on how much expenditure on wholesale energy occurs during these peak demand periods

(b) the value to consumers of changes to wholesale electricity prices inclusive of interconnection charges, based on the current shares of expenditure on wholesale energy across peak, shoulder and off-peak demand periods.[6]

2.23 We estimate a 50% reduction in wholesale electricity prices inclusive of interconnection charges during peak demand periods would result in an approximate 2% increase in electricity consumption during these peak demand periods (other things being equal). Valued at peak demand's current share of wholesale market expenditure, this change in demand is worth 2% x 30% x $4,000,000,000 = $24,000,000 annually, if we assume fixed annual expenditure.

2.24 In addition, the cost of consuming electricity at the GXP level at peak, irrespective of changes in demand, is on average 50% cheaper. This results in an average annual cost reduction of $600,000,000. To the extent that these cost reductions are offset by an increased cost of consuming in shoulder and off-peak periods, we need to deduct these higher costs of consumption in other periods from the lower cost (benefit) of peak period consumption.

Consumer surplus approach

2.25 We have used a consumer surplus assessment to estimate consumer welfare benefits across all consumers.

2.26 Our estimates of consumer welfare benefits reflect the following 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) optimal decision making, meaning that consumers are assumed to minimise the cost of reaching a given level of welfare.

2.27 The consumer surplus assessment is the standard approach to approximating consumer welfare benefits. It assumes that consumer demand:

(a) is linearly related to prices

(b) does not vary by income level

6 For example, with a 30% share of current wholesale energy expenditure shares, peak demand is vastly more valuable than demand during shoulder and off-peak demand periods.

(c) during peak demand periods does not depend on demand at other times.[7]

2.28 The last of these assumptions does not mean that, if peak demand depends on demand at other times, we cannot use consumer surplus changes to measure welfare changes. Rather, it means that dependence needs to be taken into account before assessing changes in demand and thus changes in consumer surplus.

Effects on investment in grid-connected generation

2.29 Under the proposal we expect increased peak demand from removing the RCPD charge to lead to higher wholesale energy prices and thereby increased investment in generation.

2.30 In addition, changes to interconnection charges levied on generators have the potential to alter the rate of new investment in generation by changing costs of new investment. In locations where charges decline, this could promote more rapid investment in generation. In locations where charges increase, investment could be reduced.

2.31 Wholesale energy prices under the proposal could be higher or lower than wholesale energy prices under the baseline or the other options modelled. This depends on when the wholesale energy prices are compared against each other over the period of the assessment, and the percentage of total demand that occurs in peak periods (when generation capacity and transmission capacity are most limited) and in off-peak periods.

2.32 Generation investment is a path-dependent process, with investment jointly determined alongside other market characteristics. For example, the exact timing of new generation investments is conditional on the timing of changes in wholesale prices, demand, and generators' operating costs and investment costs. However, the path of wholesale prices, demand and generator's costs is also influenced by generation investment.

Cost of generation not locating in regions with recent investment in capacity

2.33 The modelling of efficient grid use also covers the cost of generation not locating in regions with recent transmission investment in export capacity.

2.34 An increase in transmission charges (benefit-based charges under the proposal or SIMI charges under the baseline) following such transmission investment would reduce investment in efficient generation plant. This increases wholesale prices and causes consumer demand to be lower.

2.35 These costs are not identified separately in our results, because they are only one part of the generation investment decision. The results from the grid use modelling reflect the net results on nodal energy prices from increased demand (upward pressure on prices), subsequent increases in generation investment (downward pressure on prices), and higher transmission charges potentially impeding investment in the most efficient generation (upward pressure on prices).

Effects on the efficiency of investment in distributed energy resources

2.36 We estimate the proposal would materially improve the efficiency of future investment in distributed energy resources.

2.37 Highly concentrated peak transmission charges could be expected to cause inefficient investment in distributed energy resources under the baseline, done to avoid the peak

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7 These standard assumptions for (quasi-) linear demand are implicit in the original paper that established 'dead-weight loss' triangles as measures of the efficiency costs of market distortions caused by commodity taxes. See Harberger, A. C. (1964) The Measurement of Waste. The American Economic Review, 54(3), 58–76.

transmission charges. Economic agents are assumed to invest in distributed energy resources that are:

(a) cheaper than peak electricity prices *inclusive* of interconnection charges, but

(b) more expensive than peak electricity prices *exclusive* of interconnection charges.

2.38 The extent of any such inefficiency depends critically on the relative cost of new technologies. Our assessment suggests that, under the baseline, over the next 20 years the falling cost of new technologies is likely to cause a reasonable amount of inefficient investment in utility-scale batteries that cost more than peak electricity prices exclusive of interconnection charges. This assessment is based on the gains from investing in utility-scale batteries in order to avoid RCPD charges and to arbitrage wholesale energy prices.

2.39 Storage technologies are the most relevant technologies for our assessment. This is because other distributed energy technologies are either already economic, under limited circumstances (such as distributed wind generation), or do not affect peak electricity prices inclusive of interconnection charges, unless storage costs are considered (such as in the case of solar generation).

2.40 Under a regime of peak transmission interconnection charges (i.e., the baseline), investors can use utility-scale batteries to purchase electricity off-peak and sell the electricity into the wholesale market during peak and shoulder periods, while also avoiding transmission charges.

2.41 Under the baseline, this increases transmission prices during RCPD periods, because Transpower's revenue from RCPD charges is recovered over a smaller volume of electricity. The prospect of higher RCPD prices when a party has been able to reduce their exposure to these transmission prices further increases the incentive on other parties to avoid using transmission-supplied electricity during coincident peak demand periods.

2.42 Investment in utility-scale batteries to avoid peak demand charges would have the effect of reducing the need for transmission investment. However, this reduction is economically inefficient to the extent that the investment in utility-scale batteries is occurring only because of RCPD transmission charges[8] and is further accelerated from the ratcheting of RCPD transmission charges.

2.43 It should be noted the CBA only considers the incentive investors would have to invest in utility-scale batteries solely for the purpose of arbitraging energy costs and avoiding peak transmission charges.

Changes in interconnection transmission investment costs and benefits

2.44 Our final step in quantifying the net benefits from more efficient grid use under the proposal, is to assess the effect of changes in the costs and benefits of interconnection transmission investment.

2.45 We treat transmission investment as being determined exogenously.

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8 Noting that nodal prices provide signals of incremental transmission costs that could be efficiently avoided through battery investment. As the International Energy Authority has stated: "A trading arrangement based on LMP [locational marginal pricing] takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments". International Energy Agency, *Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience*, Paris, 2007. http://www.iea.org/publications/freepublications/publication/tackling_investment.pdf

Key working assumptions about transmission costs

2.46 Our estimates of transmission costs are based on:

(a) Transpower's expenditure forecasts in its 2020 integrated transmission plan schedules for 2021 to 2035[9]

(b) an assumption that operating expenditure and base capex will remain constant, after adjusting for inflation, after 2035[10]

(c) judgment based estimates of major capex required after 2035, informed by Transpower's grid planning and strategy reports[11].

2.47 Our revenue forecast for Transpower assumes:[12]

(a) Transpower's weighted average cost of capital is a constant 4.6% (real) of Transpower's regulatory asset base (RAB)

(b) all of Transpower's assets are depreciated at a constant 5% per annum

2.48 We use these simplified assumptions:

(a) to apportion future transmission expenditure to Transpower's revenue

(b) to determine the rate at which the residual interconnection charges are expected to decline over time under the proposal.

2.49 These assumptions do not match the precise rates used in calculating Transpower's allowable revenue or actual revenue (cashflow). However, simplified assumptions are necessary in our modelling, to limit the complexity of the CBA. Furthermore, the same assumptions are applied under the proposal and the baseline. This means the assumptions have no significant effect on our measurement of the economic welfare and efficiency effects of the proposal. Table 5 presents a summary of the forecast transmission revenue used in the CBA.

Table 4: Forecast interconnection revenue

Proposal values reflect the central scenario for the proposed TPM. Growth is annual average growth 2024-2044

	Component	Value	Growth	Load share	Generation share
Pricing year ended 2024					
Baseline	AC	584		100%	
	DC	84			100%
	Total	668		87%	13%
Proposal	Benefit-based	278		60%	40%

9 https://www.transpower.co.nz/keeping-you-connected/industry/rcp3/rcp3-updates-and-disclosures

10 This was considered a broadly neutral assumption to make given that potential efficiency/productivity gains might imply lower spending while increased demand might be taken to imply higher spending.

11 E.g. https://www.transpower.co.nz/NZGP

12 Refer to Table 21.

	Component	Value	Growth	Load share	Generation share
	Residual	390		100%	
	Total	668		83%	17%
Pricing year ended 2044					
Baseline	AC	777	1.03%	100%	
	DC	86	0.08%		100%
	Total	863	0.92%	90%	10%
Proposal	Benefit-based	629	2.96%	61%	39%
	Residual	234	-1.81%	100%	
	Total	863	0.92%	72%	28%

Source: Electricity Authority

Notes:
1. $2018 millions
2. Sub-totals may not sum to totals due to rounding

Key working assumptions about the relative benefit of transmission investments

2.50 To assess the costs and benefits of the proposed benefit-based transmission charge, we need to simulate how the benefit-based charge might be allocated. To do this we replicate the methods in the proposed TPM, albeit in a simplified fashion given the complexity of actual benefit calculations to be used.

2.51 We use three methods to allocate benefit-based charges:

(a) shares of benefits from specific major capex investments where Transpower has estimated customers benefits

(i) HVDC investments, where we use benefit shares calculated as part of the calculation of historical (schedule 1) investments

(ii) Waikato Upper North Island (WUNI) from the case study in Transpower's 30 June 2021 reasons paper

(iii) Clutha Upper Waitaki project from the case study in Transpower's 30 June 2021 reasons paper

(b) shares of benefits from base capex are allocated using the matrix established for allocating benefits from investments under the simple method, supplemented by illustrative projections of locations of investment[13]

(i) Transpower's forecast of locations of refurbishment and replacement (R&R) base capex investments to 2025 (i.e. RCP3)

13 Actual base capex is flexible as to the actual works completed and the locations where investment takes place. Thus the purpose of these investment projections is principally to ensure that base capex is not over (under) allocated in areas with small (large) asset bases.

(ii) extrapolations of shares of enhancement and development spending in Transpower's RCP3 proposal, by high level transmission pricing region (UNI, LNI, USI, LSI)

(iii) shares of R&R base capex beyond 2025 using regional shares of counts of assets adjusted for lower amounts of spending on low voltage assets based on Transpower's forecasts of R&R investments for RCP3 (low voltage share of 33%)

(c) shares of benefits from major capex where we have no prior information as to benefits are allocated based on the method used in the guidelines CBA for allocating benefit-based charges:

(i) 50% of transmission investment cost ascribed to economic transmission investments is allocated in proportion to each grid user's share of the loss and constraint excess (LCE)

(ii) 50% of transmission investment cost ascribed to reliability transmission investments is allocated—

1. between consumers and generators in proportion to the value of reliability to consumers ($20,000 / MWh) and generators ($200 / MWh) (i.e., 100:1 consumers:generators), and

2. amongst distributors and grid-connected consumers in proportion to each party's share of peak demand, and

3. amongst grid-connected generators in proportion to each generator's share of peak generation.

2.52 These allocations are simplifications made to keep the CBA modelling manageable. That is, we are not suggesting the costs of major transmission investments would actually be allocated in this way if the proposal were to be adopted. The Authority considers it reasonable to adopt these simplifying assumptions for the purposes of the CBA.

2.53 The LCE measures the cost of transporting electricity across the transmission network. For consumers, the LCE is the difference between the price paid in a region for electricity and the average price paid nationally to generators for electricity they produce. For generators, the LCE is the difference between the price paid for electricity they produce and the average price paid by consumers, nationally, for electricity they consume.

2.54 Our modelling considers changes in LCE to ensure the proposal's benefits are not overstated by ignoring the effect of higher peak demand on losses and constraints. Peak LCE (transport costs) is modelled as a premium (discount) on national energy prices in areas (or model backbone nodes) where demand exceeds (is below) generation. We assume LCE is, in absolute terms, increasing in proportion to demand growth (see paragraphs 2.184 to 2.196).

2.55 The modelling does not consider other factors that contribute to LCE, such as operational changes to grid constraints. To do so would add considerable complexity to the analysis (raising the need to model power flows and system constraints), when these factors are as likely to be affected by operational decisions not related to changes in the TPM.

2.56 Using the LCE as a measure of some of the benefit consumers and generators receive from transmission investment reflects the economic benefit associated with grid investments reducing losses and mitigating constraints across the grid. Consumers whose costs are higher, and generators whose revenue is lower, than in the absence of the grid investment are assumed to not benefit from it.

2.57 The proposal allows for transmission investment benefits to be calculated on a project-by-project basis and benefit-based charges to be calculated accordingly. However, the above working assumptions allow the CBA to proceed without the need for asset-by-asset analyses of transmission investment benefits.

Potential for changes in the availability of generation in a local area

2.58 The calculation of the benefit of transmission investment considers changes in the availability of local generation (i.e., within one of the 14 areas (grid backbone nodes) in the model—see paragraph 2.76). When local generation is scarce:

(a) benefits of transmission to local consumers increase, because transmission provides access to energy at lower prices

(b) costs of transmission to local generators increase, because transmission increases the supply of generation competing with local generation and lowering local prices.

2.59 We take this into account by considering the frequency with which each of the 14 areas in the model has historically faced situations where local load exceeded local generation (i.e., where the area was a net importer). The model also considers the size of mark-ups over, or discounts under, average generation costs (i.e., transport costs) that typically exist during periods of abundant and scarce local generation.

Table 5: Scarcity of local generation, price mark-ups and discounts

Average mark up (local price over national average). 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

2.60 Table 6 above summarises our assumptions about scarcity of local generation during peak demand periods and transport cost mark-ups (averages across all times of use). This shows the extent to which generation has historically been always scarce during peak demand periods in the north of the country (i.e., at the Otahuhu and Marsden backbone nodes) and never scarce during peak demand periods at the Benmore and Roxburgh backbone nodes.

2.61 This approach to measuring the benefits of transmission assets is consistent with efficient pricing, insofar as the costs of generation and consumption that are reflected in transport charges provide efficient price signals for additional investment in generation or for additional demand. Other things (e.g., fuel costs) being equal:

(a) it is less costly (more efficient) to increase demand where generation is abundant

(b) it is less costly (more efficient) to install generation where demand is abundant, and generation is scarce.

Cost of transmission investment brought forward

2.62 We assume transmission investment under the baseline is efficient (conditional on the baseline growth rate of peak demand). We also assume the long-run level of transmission investment is proportional to peak MW demand.

2.63 We use estimates of the long-run average incremental cost (LRAIC) of transmission to estimate, by transmission pricing region, the cost of transmission investment brought forward under the proposal due to higher peak demand. The cost of transmission investment brought forward under the proposal, by transmission pricing region, is the present-valued difference between growth in peak demand under the proposal multiplied by LRAIC and growth in peak demand under the baseline multiplied by LRAIC.[14]

2.64 Our estimates of LRAIC by transmission pricing region are built up from:

- Transpower's forecast major capex
- Transpower's forecast enhancement and development (E&D) base capex
- Transpower's forecasts of growth in peak demand by transmission pricing region
- judgment to assign forecast capex to transmission pricing regions
- an assumption that incremental operating expenditure is 2.2% of capex.[15]

2.65 Our estimates of LRAIC by transmission pricing region are set out in Table 7. These estimates fall within the range of incremental costs mentioned by Transpower in its 2017 report on "Battery storage in New Zealand".[16]

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14 To be precise, the measure for increased peak demand that is used is the increase in maximum peak demand observed for all model years to date.

15 Based on indicators of incremental investment-related operating expenditure over time. For example, Transpower's core transmission-related operating expenditure was between 2.2% and 2.7% of the closing asset value between 2015 and 2019. Estimating typical incremental investment-related operating expenditure using data over such a short period is somewhat problematic. However, we note that the same ratio for Powerlink in Australia averaged 1.7% between 2008 and 2019. Powerlink is probably the best Australian transmission network to compare Transpower with—long and stringy, with one big city at one end, generation at the other end, and large industrial loads scattered around the transmission network. Acknowledging that the number we use will be somewhat imprecise, we have chosen to use 2.2% as it sits in the middle of the range of 1.7% for Powerlink and the upper end of the observed range for Transpower.

16 Transpower reported a marginal cost range of $30,000 to $80,000 per MW in its 2017 publication "Battery storage in New Zealand". Although the numbers shown in our table are average rather than marginal costs, our average

Table 6: Transmission investment, incremental costs
Present value

	NZ	UNI	LNI	USI	LSI
Capital cost increment ($m)	881.7	432.8	170.0	205.2	73.7
Cost increment ($m), with incremental opex @ 2.2%	901.1	442.4	173.8	209.7	75.3
Demand increment (MW)	947.8	490.2	269.1	355.0	81.3
Long-run average incremental cost ($/MW)	950,753	902,350	645,768	590,622	925,501

Source: Electricity Authority

2.66 In calculating the cost of transmission investment brought forward, we use:

(a) forecast E&D base capex, E&D listed capex and major capex included in Transpower's RCP 3 proposal (for commissioning in RCP 3 and beyond)

(b) forecast major capex beyond that in the RCP 3 proposal, using Transpower's Transmission Planning Report 2020 as a guide.

2.67 Data from the RCP3 proposal has been used because it provides the sort of detail needed to calculate location-specific incremental costs (i.e. highly specific project information). And while the RCP3 proposal data is out of date, our estimates are intended to capture structural differences in incremental costs and a reasonable estimate of overall incremental costs, rather than highly specific and time-dependent incremental costs.

2.68 The CBA includes the following major transmission capex:

(a) Waikato and Upper North Island (WUNI) voltage management (stages 1 and 2)

(b) Bombay - Otahuhu regional capacity

(c) South Island reliability—lower South Island (Clutha - Upper Waitaki)

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

(e) Upper South Island voltage stability—switching station at Rangitata and a new line into Islington

(f) Transmission capacity between Bunnythorpe and Whakamaru—upgrade of Bunnythorpe - Whakamaru circuits / new Linton - Redclyffe 220 kV double circuit[17] / Wairakei Ring upgrade (series reactor installed on the Atiamuri–Ohakuri circuit)[18]

(g) Increase to 400 kV the operating voltage from Whakamaru to Brownhill Road—two additional 220 kV cables from Brownhill Road north into Auckland and substation development at Whakamaru and Brownhill Road

(h) Waikato regional interconnecting capacity

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cost estimates imply marginal costs of between $33,800 and $51,900 (based on bringing the average costs forward by one year).

17 A driver of this investment is expected development of significant amounts of wind generation in the Wellington – Wairarapa – Hawkes Bay regions in the medium to long term and the need to provide diversified transmission capacity in the vicinity of the Remutaka and Tararua Ranges.

18 For the purposes of the CBA, the capex against these three major investments is fungible. For example, a new Linton - Redclyffe circuit could be viewed as a substitute for an upgrade of the Bunnythorpe - Tokaanu circuits, meaning some of the capex allowance for these respective projects could be redirected to an upgrade of the Wairakei Ring beyond a series reactor on the Atiamur–Ohakuri circuit (eg, a new double circuit Wairakei - Ohakuri - Atiamuri - Whakamaru line).

(i) Enabling new connections—a yet-to-be-determined programme of work to enable rapid, easy connection of renewable energy projects.

2.69 Note we estimate the cost of transmission investment brought forward across the entire interconnected transmission network over the CBA's 28-year assessment period—we do not estimate this cost by specific transmission projects.

Benefit of transmission investment brought forward

2.70 If grid investment is brought forward, due to increased peak demand, then benefits from grid investment will also be brought forward. To calculate the net cost of transmission investment brought forward by the proposal, we deduct, from incremental investment costs, the difference between projected peak LCE under the proposal and projected peak LCE under the baseline.

2.71 As with estimating the cost of transmission investment brought forward, we do not estimate the benefit of bringing forward a single transmission investment or even several specific transmission investments. Instead, we estimate the net benefit of lower projected peak LCE across the entire interconnected transmission network over the CBA's assessment period.

Models for assessing benefits from more efficient grid use

2.72 We have used the following three models to estimate (quantitatively) the net benefits of more efficient grid use:

(a) a model of consumer electricity demand

(b) a model of investment in grid-connected generation

(c) a model of distributed energy resource (utility-scale battery) investment.

2.73 These conceptually distinct models are then combined to form a single overall model.

2.74 We have selected these models:

(a) to strike a balance between:

(i) generality and flexibility—high-level models that reflect a range of scenarios for future market conditions and outcomes under the proposed TPM guidelines, and

(ii) detail—low-level models about existing demand and supply conditions, which can estimate plausible magnitudes of effects

(b) to capture economic dynamics and decisions that are central to transmission pricing and to consumer welfare

(c) to avoid errors and ensure the results can be broken down into intuitive causes and effects.

2.75 The models involve:

(a) taking input data on electricity volumes and prices (of generation and demand) for a given year,[19] then

(b) calculating a new set of prices and demands for the subsequent year, either:

(i) in terms of known forecast information, or

[19] Transmission pricing capacity measurement periods (August years).

(ii) assumptions about how transmission customers are forming expectations about future electricity prices.

2.76 The models distinguish electricity demand and generation in New Zealand by:

(a) 14 areas (backbone nodes)

(b) electricity demand connected to:

(i) distribution networks

(ii) the transmission network

(c) grid-connected generation, by plant type

(d) time of use across a day (00:00–24:00 hours)

(e) energy source

(f) grid offtake during peaks in electricity demand (the 1,600 trading periods with the highest electricity demand in a calendar year ("the peak demand period"))

(g) electricity demand served by distributed generation, including utility-scale batteries, during the peak demand period

(h) electricity demand met by grid offtake and distributed generation, including utility-scale batteries, during shoulder demand trading periods (the next 3,075 trading periods with the highest electricity demand in a calendar year, after the 1,600 trading periods with the highest electricity demand ("the shoulder demand period"))[20]

(i) electricity demand met by grid offtake and distributed generation, including utility-scale batteries, during off-peak demand trading periods (the 12,845 trading periods with the lowest electricity demand in a calendar year ("the off-peak demand period"))

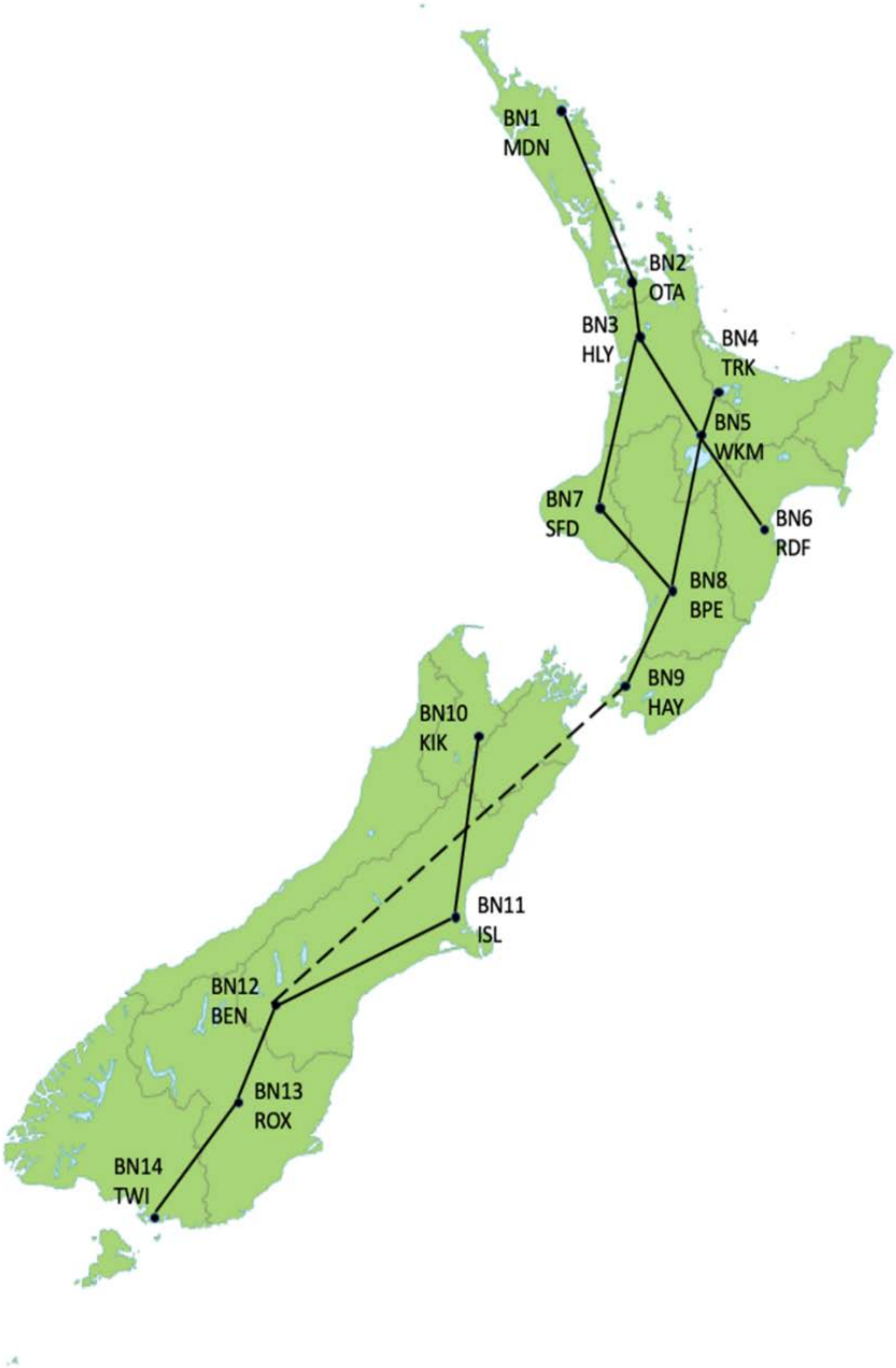
(j) grid generation in each of the peak, shoulder and off-peak demand periods.

2.77 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.

2.78 The area breakdown used in the model of electricity demand is based on key points of connection to the grid. We refer to these in this CBA as backbone nodes. Figure 2 presents the location of these backbone nodes and illustrative transmission line connections between them.

[20] When ranking trading periods, we give the same ranking to trading periods with the same MWh. The maximum number of trading periods included in peak demand periods for one region is 1,641, while for shoulder trading periods it is 3,260.

Figure 2: Simplified 14 backbone node grid



Source: Electricity Authority

2.79 North to south, the backbone nodes are:

(a) Marsden Point in Northland (MDN)

(b) Otahuhu in Auckland (OTA)

(c) Huntly in the Waikato (HLY)

(d) Tarukenga in the Bay of Plenty (TRK)

(e) Whakamaru in the central North Island (WKM)

(f) Stratford in Taranaki (SFD)

(g) Redclyffe in Hawke's Bay (RDF)

(h) Bunnythorpe in the Manawatu (BPE)

(i) Haywards in Wellington (HAY)

(j) Kikiwa in the upper South Island (KIK)

(k) Islington in Canterbury (ISL)

(l) Benmore in South Canterbury (BEN)

(m) Roxburgh in Otago (ROX)

(n) Tiwai in Southland (TWI).

Model 1: Demand model

2.80 The demand model and its associated parameter estimates play a crucial role in the CBA, because consumption/demand is the key determinant of consumer welfare.

2.81 Furthermore, as the CBA is assessing changes in the incidence of prices, the results are highly sensitive to assumptions about:

(a) the relative responsiveness of electricity demand to changes in electricity prices during the peak demand and off-peak demand periods, and

(b) the relative responsiveness of different consumers (or regions) to changes in electricity prices.

2.82 This is why there is the need to establish a well-specified (logically consistent) and robustly estimated model of demand response.

2.83 The demand model needs to account for:

(a) economic limits on the amount by which electricity demand can increase (aggregate income constraints)

(b) substitution of electricity demand, across time periods and between energy sources

(c) non-constant price responsiveness (elasticities that vary with price levels and changes in aggregate income levels over time)

(d) potential effects on consumers if wholesale electricity prices rise when transmission prices decline.

Form of demand model

2.84 The demand model is an expenditure system—specifically an 'almost ideal demand system'.[21] This form of model and variants of this form of model have been widely used in New Zealand and elsewhere for analysing welfare effects of price changes.[22]

2.85 This form of model accounts for the allocation of demand over different goods (or time periods) and for different types of consumers.

2.86 Useful properties of this form of model include that:

(a) demand is limited by prices and available expenditure (income constraints), and changes in demand are limited by adding-up constraints, such that if expenditure on one product increases, expenditure on other products must fall

(b) cross-price elasticities can be calculated, such as changes in demand for off-peak energy when peak energy prices increase (highly relevant for analysis of transmission prices that may cause load shifting between peak, shoulder and off-peak demand periods).

2.87 In the description that follows, the term "consumers" covers both businesses and households. The model presented below is typically associated with households or individuals. However, the foundations for the model are also found in models of production. That is, the almost ideal demand system is derived from a specific expenditure function that defines the minimum expenditure needed to meet a given level of welfare. This is analogous to a firm's cost minimisation problem for a given level of output.

2.88 Consumers are assumed to choose when to consume or what to consume based on a log expenditure function:

$$\ln \mathrm{e}(p_t, U_t) = \alpha_0 + \sum_{i=1}^{4} \alpha_i \ln p_{it} + \frac{1}{2} \sum_{i=1}^{4} \sum_{j=1}^{4} \gamma_{ij} \ln p_{it} \ln p_{jt} + U\beta_0 \prod_{i=1}^{4} p_{it}^{\beta_i} \quad \text{Equation 1}$$

Where:

(a) e is expenditure

(b) p_{it} is price of product i at time t (in our application there are 4 products)

(c) U is some unobserved level of utility or welfare

(d) the α_i parameters represent consumer preferences and marginal budget shares of expenditure in the absence of relative price differences

(e) the γ_{ij} terms determine the effects of relative prices of products on expenditure for each of the i products given the price of the jth product

(f) the β terms determine income effects and are positive for goods that are luxuries and negative for normal goods.

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21 Deaton, A., & Muellbauer, J. (1980). An Almost Ideal Demand System. The American Economic Review, 70(3), 312–326. The model used to estimate the parameters is, ultimately and for simplicity, the linear approximation to the almost ideal demand system.

22 See for example, Filippini, M. (1995). Swiss Residential Demand for Electricity by Time-of-Use: An Application of the Almost Ideal Demand System. The Energy Journal, 16(1), 27–39 for a previous use for analysing time of use electricity demand; Creedy, J. (2004). 'The effects of an increase in petrol excise tax: the case of New Zealand households', National Institute Economic Review, 188, April, 70–79, for an application of a linear expenditure system; Gomez-Lobo, A. (1996). 'The welfare consequences of tariff rebalancing in the domestic gas market'. Fiscal Studies, 17(4), 49–65 for an application using the quadratic almost ideal demand system.

2.89 Demand functions, derived from the expenditure function, are:

$$x_{it}(p_{it}, m_t) = \frac{m_t}{pi}\left(\alpha_i + \sum_j \gamma_{ij} \ln p_{jt} + \beta_i \ln\left(\frac{m}{P_t}\right)\right) \qquad \text{Equation 2}$$

Where m is income and P is a price index:

$$\ln P = \alpha_0 + \sum_{i=1}^{4} \alpha_i \ln p_{it} + \frac{1}{2}\sum_{i=1}^{4}\sum_{j=1}^{4} \gamma_{ij} \ln p_{it} \ln p_{jt} \qquad \text{Equation 3}$$

2.90 In our application, the price index is replaced by a Laspeyres price index (the linearised almost ideal form of model).

2.91 The expenditure share (s_{it}) form of the demand function is:

$$s_i = \alpha_i + \sum_j \gamma_{ij} \ln p_{jt} + \beta_i \ln\left(\frac{m}{P_t}\right) \qquad \text{Equation 4}$$

2.92 A key assumption in our use of this model is that demand for energy is determined after determining demand for other products.[23] Thus, there are two stages in the demand system.

First stage of demand modelling: consuming energy vs other goods

2.93 In the first stage of the demand modelling, consumers choose between consuming energy and consuming other goods. This stage includes additional exogenous growth in demand to represent electrification of energy demand and effects of climate policies.

2.94 For the first stage modelling, aggregate energy demand is differentiated by:

(a) the demand of consumers directly connected to the transmission network (nationally)

(b) the demand of consumers connected to a distribution network, by network reporting region.

2.95 These are the lowest levels of aggregation for which total activity, or income and expenditure, proxies can be obtained. These proxies are needed to estimate the two components of the demand model.

2.96 For consumers connected to a distribution network, we model demand by region on a per-ICP basis (x_{rt}), assuming that aggregate demand rises proportionally with population (N_t) and income (M_{rt}) and declines proportionally with higher average electricity prices (p_{rt}). This yields total regional demand for distribution-connected consumers (X_{rt}):

$$X_{rt} = x_{rt}(p_t, M_{rt}).N_t \qquad \text{Equation 5}$$

2.97 In practice, we simply model changes in demand according to population growth (on a one-for-one basis) and income growth (also on a one-for-one basis), using estimated income elasticities of demand that are constant for all regions (η_{rt}). That is:

$$X_{rt} = \left(\frac{N_{rt}}{N_{rt-1}} + \eta_t \frac{M_{rt}}{M_{rt-1}} - 1\right).\left(X_{rt-1} + \dot{X}(\Delta p_t)\right) \qquad \text{Equation 6}$$

Where the term $\dot{X}(\Delta p_t)$ denotes the change in demand in response to prices.

2.98 The income elasticities have been increased from the estimated value to capture increased electricity demand growth due to electrification of energy demand and climate change policies or related preference shifts due to subsidies or increased prices for fossil fuels. This additional demand is treated as exogenous (i.e. outside the model).

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23 This is a simplification. An alternative approach would be to include estimates of aggregate expenditure on all other, non-energy, products.

2.99 The size of the increase in the income elasticities is calculated to ensure that demand growth rates are the same as those projected by the CCC (2021) in its demonstration pathway, after accounting for income and population growth and our estimated income elasticity of 0.11. We assume a similar level of long run demand for electricity, regardless of whether NZAS closes or remains open. As such:

(a) the income elasticity parameter is raised from 0.11 to 1.0225 in scenarios when NZAS closes in 2024, to lift exogenous growth from 0.9% per year based on population and income growth to 2.0% with increased electrification

(b) the income elasticity parameter is raised from 0.11 to 0.577 in scenarios where NZAS remains open, which raises exogenous growth from 0.9% per year based on population and income growth to 1.5% with increased electrification and NZAS remaining open.

2.100 The change to the income elasticity is used as a device for increasing exogenous growth. It is not intended to imply a change in income elasticity.

2.101 The price term in Equation 6 is based on aggregate price elasticities of demand and changes in prices relative to historical average prices (2008-2020). The price measure used is a price index using historical expenditure shares by time of use.

2.102 This differs from the approach taken in the Guidelines CBA where demand was modelled as responding to changes in prices regardless of price levels. The approach taken in the proposed TPM CBA, based on price levels, better captures effects on demand of persistently low or high prices due to shocks to demand or supply or structural changes in the cost of electricity supply such as if there is a significant change in supply of low marginal cost intermittent renewables. For example, if NZAS closes prices fall and demand increases. Subsequent increases in demand then cause an increase in prices, other things being equal. If aggregate demand is based only on percentage changes in prices then demand will fall, regardless of whether or not the prevailing price remains low relative to historical averages.

2.103 The price term in Equation 6 also includes an adjustment to account for negative income effects associated with fixed charges. Fixed charges do not impact on prices but on income available to spend on electricity. The incremental impact of a dollar less income to spend on electricity, after paying fixed charges, is the expenditure elasticity excluding exogenous demand effects. Thus, the price term in Equation 6 is

$$\dot{X}(\Delta p_t) = \bar{e}.\left(\frac{p_t}{p_h} - 1\right) - \frac{f}{e}\eta$$

Where $\bar{e}$ is the aggregate price elasticity, p_t is the current period price index, p_h is the historical average price index, f is fixed charges, e is total expenditure in the previous period and η is the expenditure/income elasticity.[24] This too is a departure from the Guidelines CBA, where consumers' transmission charges were modelled as a $/MWh charge across total electricity consumed.

2.104 In implementing this equation we use only the price elasticity of demand parameter – given that the estimated aggregate price elasticity of demand is the same value, in absolute terms, as the expenditure/income elasticity.

2.105 Population growth used in the modelling is based on Statistics New Zealand population growth projections. Incomes are modelled using an assumed national average growth rate,

24 In implementing this equation we use only the price elasticity of demand parameter – talking advantage of the fact that the estimated aggregate price elasticity of demand is the same value, in absolute terms, as the expenditure/income elasticity.

with regional variations based on observed historical deviations from national trend income growth.

2.106 For consumers directly connected to the transmission network, we assume that demand grows according to regional income growth and in line with the same exogenous growth rates as distribution-connected consumers (i.e., as for distribution-connected demand, but without the term reflecting population growth). This is a simplification employed to avoid having to forecast demand for output and input costs of large industry. The absence of the population growth parameter means that large industry is a declining share of electricity demand and, implicitly, of economic output, roughly in line with empirical trends.

2.107 Aggregate price elasticities of demand for transmission-connected consumers are based on a translog cost function that follows the same general approach as for the time-of-use model. A single (average) elasticity is used for all industry due to difficulties differentiating between quite different demand characteristics of firms in the same industry (such as distinguishing steel and aluminium demand in the basic metals industry).

2.108 To adjust demand for fixed transmission charges, we assume that transmission-connected customers income elasticities are equal to their price elasticity of demand as is the case for mass-market customers. This assumption is made in the absence of a specific estimate of income/expenditure elasticities for these kinds of customers.

Second stage of demand modelling: grid-connected vs distributed generation

2.109 In the second stage of the demand modelling, consumers choose between consuming:

(a) grid-exported electricity, measured in MWh

(b) electricity from distributed generation, measured in MWh.

2.110 In the second stage modelling, demand is differentiated by time of use. This is to reflect that electricity consumed at different times is a distinct product. We use three periods of demand:

(a) peak

(b) shoulder (near peaks)

(c) off-peak.

2.111 We have used statistical data reduction analysis (clustering and factor analysis) to determine the time periods to include in each of the three demand periods. We have supplemented this analysis with expert judgment about optimal cut-off times for defining the three demand periods.

2.112 The peak demand period comprises 1,600 trading periods, which is a substantially larger number of trading periods than Transpower uses to calculate interconnection charges. We have done this to capture consumer responses to expected electricity prices, with these responses reflecting the uncertainty of peak transmission charge periods, which are determined after the fact.

Calculating elasticities

2.113 Once the parameters of the demand system have been estimated, elasticities from the model can be calculated directly from parameters, as follows

(a) Simple (Marshallian) demand elasticities:

$$e_{ij}\begin{cases}-1+\frac{\gamma_{ij}}{s_i}-\beta_i s_{j0}, i=j\\ \frac{\gamma_{ij}}{w_i}-\beta_i s_{j0}, i\neq j\end{cases}$$ Equation 7

(b) Expenditure elasticity:

$$\eta_i = 1+\frac{\beta_i}{s_i}$$ Equation 8

Fitted expenditure shares by time of use

2.114 In an approach analogous to modelling of aggregate demand based on price levels, we model changes in expenditure shares, by time of use and relative to a historical benchmark, using the estimated demand system parameters.

2.115 Predicted expenditure shares by time of use are based on the difference between fitted expenditure shares in the model base year (2020) and fitted expenditure shares at new prices. Thus all changes in expenditure shares are measured relative to a historical benchmark.

2.116 In fitting expenditure shares by time of use, limits have been placed around expected relative prices by time of use. This is necessary because the empirical model parameters do not support any value for relative prices. Ratios of the natural logarithm of peak prices to the natural logarithm of off-peak prices and the natural logarithm of peak prices to the natural logarithm of shoulder prices are limited to a value of no less than 0.67, for the purposes of predicting expenditure shares. The natural logarithm of expected shoulder prices is limited to values no less than 0.20 higher than off-peak prices.

Consumer surplus changes

2.117 Changes in consumer welfare are measured by changes in consumer surplus (ΔCS_t), calculated as:

$$\Delta CS_t = \frac{1}{2}(\bar{p}_i - p'_{it})x'_{it} - \frac{1}{2}(\bar{p}_i - p_{it})x_{it}$$ Equation 9

Where $\bar{p}_i$ is maximum price, by time of use, beyond which consumer surplus is zero. Demand and prices under the proposed TPM are denoted x'_{it} and p'_{it} while demand and prices under the baseline are x_{it} and p_{it}.

2.118 This approach to measuring consumer surplus changes essentially calculates total consumer surplus under the proposal and total consumer surplus under the baseline and measures the difference between the two. This differs from the formula used to calculate consumer surplus changes in the Guidelines CBA. This more direct method is necessary for dealing with the fact that, under the proposal, fixed effects cause an income effect that impacts demand without directly impacting prices. Thus it is not appropriate to calculate changes in consumer based on changes in prices.

2.119 The maximum price used to calculate consumer surpluses has been calculated using historical average prices by time of use (p_i^h) and the relationship between maximum prices and demand elasticities ($\bar{e}$) with linear market demand

$$\bar{p} = p_i^h.\left(1-\frac{1}{\bar{e}}\right)$$

2.120 For the calculation of maximum prices, the long run elasticity of demand has been used (-0.74, see Table 10 below). This is appropriate because the CBA is analysing impacts of structural changes over a long period of time. Shorter run elasticities would significantly increase maximum prices and would imply that consumers would accept and obtain surpluses under very high prices (thousands of dollars per MWh) for a very long time when in fact consumers would be likely to substitute to distributed energy sources if prices are very high.

2.121 The long run elasticity used to calculate maximum prices implies, for example, that consumer surplus is zero if wholesale electricity prices, inclusive of interconnection charges, are persistently 2.35 times higher than historical averages. Based on historical average prices between 2008 and 2020, this implies that consumers surplus is zero if prices are persistently above $246 per MWh on average, annually.

2.122 Maximum prices, beyond which consumer surplus is zero, differ for different times of use:

(a) peak demand has a maximum price of $600 per MWh

(b) shoulder demand has a maximum price of $240 per MWh

(c) off-peak demand has a maximum price of $190 per MWh.

2.123 Lower price elasticities would create much higher multipliers and much higher maximum prices. For example, the short run price elasticity of demand estimated in Table 10 below (-0.11) would place a maximum price on peak demand of $6,000 per MWh and a maximum price on total demand of $2,460 per MWh. Using such prices would significantly increase the absolute size of changes in consumer surpluses.

2.124 Prices can rise above the maximum prices used here to calculate consumer surpluses. Thus these maximums are only maximums with respect to the calculation of long run changes in consumer surpluses.

Empirical analysis to establish demand model parameters

2.125 Parameters for the first and second stages of the demand modelling are estimated separately:

(a) for the first stage, aggregate annual demand for electricity is analysed

(b) for the second stage, electricity demand by time of use is analysed.

2.126 Transmission-connected and distribution-connected demands are also analysed separately.

2.127 Similar, but not identical, empirical models are used to estimate time-of-use parameters for distribution-connected demand and transmission-connected demand.

2.128 The demand model for transmission-connected load is similar to the demand model for distribution-connected load, insofar as it is an expenditure model. However, it is an expenditure model derived from theoretical cost minimising behaviour of a profit maximising producer, while the demand model for distribution-connected load is derived from theoretical cost minimising behaviour of a utility maximising consumer.

2.129 The model used to analyse aggregate transmission-connected demand also differs from the model used to analyse distribution-connected demand insofar as transmission-connected demand is estimated using industry-level data that does not distinguish between industrial loads connected to the transmission network and to distribution networks.

Aggregate, first stage, model of industrial demand

2.130 The model of industrial demand is a translog cost model. This model is akin to a complete demand system, because it estimates shares of expenditure devoted to all inputs to production, given relative prices for these inputs. The translog cost function is derived from translog production functions, which are widely used in productivity analyses.

2.131 Here the demands (for energy inputs) that are being analysed are not exclusively transmission-connected demands, but rather industrial demands. This is due to an absence of data on transmission-connected consumers' input demands and output.

2.132 The model that is estimated is a system of equations expressing the shares of expenditure (s) on inputs to production as a function of the prices (p) of those inputs:

$$s_k = \beta_k + \delta_{kk} p_k + \delta_{kl} p_l + \delta_{ke} p_e + \delta_{kn} p_n + \delta_{ki} p_i \qquad \text{Equation 10}$$
$$s_l = \beta_l + \delta_{lk} p_k + \delta_{ll} p_l + \delta_{ke} p_e + \delta_{kn} p_n + \delta_{ki} p_i \qquad \text{Equation 11}$$
$$s_e = \beta_e + \delta_{ek} p_k + \delta_{el} p_l + \delta_{ee} p_e + \delta_{en} p_n + \delta_{ei} p_i \qquad \text{Equation 12}$$
$$s_n = \beta_n + \delta_{nk} p_k + \delta_{nl} p_l + \delta_{ne} p_e + \delta_{nn} p_n + \delta_{ni} p_i \qquad \text{Equation 13}$$
$$s_i = \beta_i + \delta_{ik} p_k + \delta_{il} p_l + \delta_{ie} p_e + \delta_{in} p_n + \delta_{ii} p_i \qquad \text{Equation 14}$$

Where:

(a) the inputs are:

(i) capital (k)

(ii) labour (l)

(iii) electricity (e)

(iv) non-electricity energy products (n)

(v) other intermediate goods (i)

(b) the β terms are constants

(c) the δ terms are coefficients (derivatives) on prices and they vary by product.

2.133 In estimating the model, we impose restrictions on the coefficients to ensure:

(a) expenditure shares sum to 1 (requiring that the β coefficients sum to 1)

(b) cross-price coefficients are symmetric (e.g., $\delta_{kl} = \delta_{lk}$).

2.134 This is achieved by transforming prices into relative prices compared to the price of intermediates (dividing each equation by p_i).

2.135 The model is estimated using the seemingly unrelated regressions method with the intermediates equation (s_i) dropped from the system to avoid singularity. The coefficients for the intermediates equation can be recovered using the adding-up constraints.

2.136 Data used for estimating this model has been sourced from:

(a) MBIE's energy statistics, for data on:

(i) annual energy volumes by industry (from energy balance tables)

(ii) annual average prices by fuel by industry, where available otherwise average industry-level prices have been used

(b) Statistics New Zealand's National Accounts, for data on:

(i) expenditure on intermediates

(ii) economy-wide inflation (GDP deflator)

(iii) compensation of employees, by industry

(iv) nominal capital stocks

(c) Statistics New Zealand's sources for statistics on employment by industry:

(i) productivity statistics, indices of labour input by industry

(ii) Quarterly Employment Survey (QES) data on fulltime equivalents (FTEs) per job

(iii) Linked Employer-Employee Dataset (LEED) data on employment by industry.

2.137 The data spans the years 1990 to 2016.

2.138 The industry breakdown in the MBIE data is less detailed than the data available in Statistics New Zealand's National Accounts. Industry data is aggregated, from National Accounts industries to energy data industries, using shares of input weights.

Results

2.139 The model is fitted for each industry in the data. A sample of model results is summarised in Table 8, for data aggregated to all industries.

2.140 To use these coefficients for the purposes of the TPM modelling, we calculate average price elasticities of input demands.

2.141 For example, the electricity own price (η_{ee}) elasticity and cross price (η_{ek}) elasticity for substitution between capital and electricity are calculated as follows:

$$\eta_{ee} = \delta_{ee} + s_e(s_e - 1) \qquad \text{Equation 15}$$

$$\eta_{ek} = \eta_{ke} = s_e + \frac{\delta_{ke}}{s_k} \qquad \text{Equation 16}$$

Where s_e is the share of costs, as defined earlier along with the parameters (δ).

2.142 Table 9 provides a summary of estimated elasticities evaluated at the mean values for expenditure shares and prices for each industry. All industries, except mining, exhibit small negative price elasticities of demand. The result for mining—that demand for electricity increases when electricity prices increase—could be due to the close relationship between demand for output from mining and energy prices, including electricity prices. Mining includes fuel for electricity generation and has output prices that rise with prices for energy commodities.

2.143 The cross-price or substitution elasticities indicate that electricity is in many cases a complement to other sources of energy. This means an increase in the price of electricity reduces demand for both electricity and other sources of energy. In the case of the aggregate 'All' industry model, this value is -2.455, such that a 1% increase in electricity prices is associated with a 2.5% reduction in demand for other energy products.

Table 7: Cost function coefficient estimates

Dependent variables are input cost shares across all industries

Input	Coefficient	Standard error	T statistic	P value
Constants:				
Capital (β_k)	0.242	0.0020	118.84	0.000
Labour (β_l)	0.251	0.0022	115.98	0.000
Electricity (β_e)	0.008	0.0021	3.79	0.000
Non-electricity energy (β_n)	0.004	0.0021	1.71	0.090
Price coefficients:				
Capital (δ_kk)	0.098	0.0112	8.81	0.000
Capital-Labour (δ_kl)	0.007	0.0080	0.94	0.352
Capital-Electricity (δ_ke)	0.025	0.0128	1.95	0.054
Capital-Non-electricity (δ_kn)	0.018	0.0090	2.04	0.044
Labour (δ_ll)	0.085	0.0111	7.66	0.000
Labour-Electricity (δ_le)	0.000	0.0116	-0.02	0.984
Labour-Non-electricity(δ_ln)	-0.027	0.0107	-2.55	0.012
Electricity (δ_ee)	-0.010	0.0233	-0.41	0.682
Electricity-Non-Electricity (δ_en)	-0.026	0.0127	-2.07	0.041
Non-electricity energy (δ_nn)	0.019	0.0147	1.32	0.189

Source: Electricity Authority

Table 8: Industry input price elasticities

Industry	s_e	Electricity (η_{ee})	Electricity-Non-electricity (η_{en})	Electricity-Capital (η_{ek})	Capital-Labour (η_{kl})
All	0.013	-0.022	-2.455	0.114	0.269
Agriculture	0.014	-0.030	3.644	0.001	0.116
Chemicals	0.019	-0.024	0.112	-0.041	0.293
Construction	0.012	-0.018	0.110	0.023	0.193
Commercial	0.013	-0.033	-2.223	0.133	0.081
Food products	0.018	-0.012	-0.291	0.005	0.373
Mechanical products	0.018	-0.012	0.091	0.022	0.204
Metal products	0.020	-0.001	-3.119	0.142	0.184
Mining	0.016	0.013	4.297	-0.400	0.192
Non-metallic minerals	0.020	-0.024	-0.389	0.012	0.380
Other	0.018	-0.082	-1.513	0.303	0.322
Textiles	0.016	-0.014	-0.875	0.042	0.253
Wood products	0.018	-0.007	-1.100	0.084	0.336

Source: Electricity Authority

Aggregate first stage model of distribution-connected demand

2.144 The model of aggregate distribution-connected demand is a dynamic panel model.[25] The model is:

$$x_{rt} = \alpha_r + \beta_p p_{rt} + \beta_l x_{rt-1} + \beta_e e_{rt} + \beta_h h_t + \beta_d d_{rt} + \beta_i d_{rt} . p_{rt} \qquad \text{Equation 17}$$

2.145 This model estimates annual grid export demand per ICP by networking reporting region (x_{rt}).

Where r is the subscript for regions and t is the time or year subscript), accounting for:

(a) regional differences in average levels of demand (so-called fixed effects, α_r)

(b) wholesale prices, by region and year, inclusive of interconnection charges (p_{rt})

25 Similar methods and models were used in Filippini, M. (2011). Short- and long-run time-of-use price elasticities in Swiss residential electricity demand. *Energy Policy*, 39(10), 5811–5817. https://doi.org/10.1016/j.enpol.2011.06.002

(c) delayed adjustments to price changes (lagged demand x_{rt-1})

(d) employee earnings per ICP (e_{rt}), as a proxy for income, by region

(e) average national heating degree days in each year (h_t)

(f) observed annual maximum distributed generation per ICP (d_{rt})

(g) interactions between prices and observed annual maximum distributed generation ($d_{rt}.p_{rt}$), to account for potential reductions in a region's exposure to wholesale prices and transmission charges when distributed generation is available.

2.146 The price and earnings variables in the model are real values deflated by national price indices. The price, earnings, and demand variables are transformed by natural logarithms and the heating degree day variable is a ratio of heating degree days to the average over 37 years.

2.147 The results of the model estimation (the β parameters and model fit statistics) are summarised in Table 10—in the column 'Final'. Other variations on the model that were also estimated are shown in columns A to I. These other models tested other combinations of predictive variables—including distribution prices. The final model and model A included regional fixed effects. The other models shown included both regional fixed effects and time-specific (year-specific) fixed effects. Model E also considered retail as a predictor of demand, rather than wholesale prices inclusive of transmission interconnection charges.

2.148 The final model was chosen on the basis that it was both the model that best explained the data, while using the fewest explanatory variables to explain demand patterns (highest adjusted R-squared).

2.149 The coefficients in the final model all have intuitively reasonable values with:

(a) a 10% increase in prices predicted to reduce demand by 1.1% (coefficient of -0.11) in the short term

(b) a 10% increase in income (earnings) predicted to increase demand by 1.1% (coefficient of 0.11)

(c) a 10% increase in distributed generation capacity reducing grid demand per ICP by 1.6%—the coefficient of -311 needs to be interpreted considering average MW per ICP of 0.0005, such that a 10% increase is an increase of 0.05 kW per ICP

(d) a 10% increase in heating degree days increasing aggregate annual grid demand by 0.1%—notably a 10% increase is not a rare event, with the standard deviation of the heating degree day index equal to 0.65

(e) an increase in distributed generation has the effect of muting the effects of prices on annual grid demand (as indicated by the positive coefficient on the interaction term).

Table 9: Dynamic panel models

Dependent variable: annual MWh consumption per ICP by network reporting region

Variable	Values	**Final**	A	B	C	D	E	F	G	H	I
Wholesale price (natural logarithm)	Coefficient	**-0.110**	-0.105	-0.31	-0.29	-0.21		-0.22	-0.22	-0.31	-0.23
	Std error	**0.04**	0.05	0.09	0.09	0.08		0.08	0.08	0.09	0.08
	p-value	**0.01**	0.02	0.00	0.00	0.01		0.01	0.01	0.00	0.01
Earnings per ICP	Coefficient	**0.11**	0.14	0.44	0.44	0.40	0.38	0.41	0.41	0.44	0.43
	Std error	**0.11**	0.13	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
	p-value	**0.30**	0.26	0.00	0.00	0.01	0.01	0.01	0.01	0.00	0.00
Prior year consumption	Coefficient	**0.85**	0.85	0.85	0.85	0.85	0.84	0.85	0.85	0.85	0.85
	Std error	**0.04**	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
	p-value	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum observed DG output, per ICP	Coefficient	**-311.02**	-310.66	-401.07	-386.62		-47.15			-401.07	36.93
	Std error	**236.09**	236.39	236.21	237.06		214.96			236.21	28.21
	p-value	**0.19**	0.19	0.09	0.10		0.83			0.09	0.19
Interaction between DG and price	Coefficient	**75.788**	76.210	100.292	97.082		19.852			100.292	
	Std error	**53.63**	53.70	53.70	53.89		48.67			53.70	
	p-value	**0.16**	0.16	0.06	0.07		0.68			0.06	
Index of heating degree days, nationally	Coefficient	**0.01**	0.01								
	Std error	**0.01**	0.01								
	p-value	**0.22**	0.39								
Retail distribution charges (per kWh, natural logarithm)	Coefficient		-0.05		0.12	0.14					
	Std error		0.11		0.15	0.16					
	p-value		0.63		0.43	0.37					
Retail charges (per kWh natural logarithm)	Coefficient						0.38				
	Std error						0.30				
	p-value						0.20				
Implied long run elasticity		**-0.74**	-0.71	-2.06	-1.90	-1.40	0.00	-1.55	-1.55	-2.06	-1.52
	R-squared	**0.633**	0.634	0.637	0.637	0.632	0.630	0.637	0.630	0.631	0.625
	Adj R-squared	**0.58**	0.58	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.56
	F-statistic	**88.11**	75.37	104.77	87.30	129.02	171.05	104.77	171.05	128.41	99.84

Source: Electricity Authority

2.150 Table 11 provides a summary of the data used in the first stage model of distribution-connected demand. This data provides important context for interpreting model coefficients.

Table 10: Dynamic panel model data, descriptive statistics
Annual data, 2010–2017, for 39 network reporting regions

	Mean	Standard deviation
MWh consumption per ICP	2.8	0.52
Wholesale price (natural logarithm)	4.4	0.29
Earnings per ICP (natural logarithm)	10.3	0.57
Maximum observed DG output, per ICP	0.0005	0.0007
Index of heating degree days, nationally	-0.4	0.65
Retail distribution charges (per kWh, natural logarithm)	2.2	0.22
Retail charges (per kWh natural logarithm)	3.2	0.12

Source: Electricity Authority

Demand by time of use

2.151 Data used for estimating demand by time of use is:

(a) annual wholesale demand

(b) demand-weighted wholesale market prices by network reporting region.

2.152 The data is derived from:

(a) final prices by trading period and point of connection

(b) metered grid offtake by trading period and point of connection

(c) reconciled demand by trading period and point of connection.

2.153 In addition to this core data, additional explanatory variables are added, as outlined in paragraph 2.159 below.

2.154 Transmission charges are included in the data, by calculating regional coincident peaks and applying the interconnection charges ($/kW per year) published in Transpower's pricing disclosures. These charges are assigned to the relevant capacity measurement period (August year), rather than pricing year in which charges are applied. This accounts for consumers responding to expected/prospective charges, rather than current charges—because current charges are unaffected by current demand decisions.

2.155 Times of use are calculated by ranking trading periods by coincident volume (MW) of demand in a transmission pricing region with:

(a) the peak being the top 1,600 trading periods

(b) the shoulder being the next 3,075 trading periods

(c) off-peak being the remaining 12,845 trading periods.

2.156 As noted above, this split is based on a cluster analysis of trading periods, by transmission pricing region. The cluster analysis identified six clusters of demand. Our interest is in peak demand, given its impacts on transmission system capacity and costs. Therefore, we chose to take the first two clusters as the peak demand period and shoulder demand period, and to combine the subsequent clusters into a single off-peak demand period.

2.157 We constructed a single set of trading periods for each time of use, using the average number of trading periods for each time of use over a 10-year period[26] across all pricing regions. This was so that we had a single, system-wide definition of peak, shoulder and off-peak demands. However, the actual dates and times (trading periods) that are used to calculate time-of-use volumes differ by transmission pricing region and year.

2.158 In addition to these three times of use, which are treated as separate products, a fourth category of demand is defined. This is consumption of energy produced off-grid—referred to here as distributed generation. This is calculated by taking the difference between reconciled load by GXP and metered grid export at a GXP.[27] Thus, four times of use are defined:

(a) peak grid demand

(b) peak distributed generation demand

(c) shoulder demand

(d) off-peak demand.

2.159 The time of use model is

$$w_i = \alpha_i + \alpha_{ri} + \delta_{si} \ln S_{si} + \sum_{j=1}^{N} \gamma_j \ln p_{ij} + \beta_i \ln \frac{X}{P} \qquad \text{Equation 18}$$

Where:

(a) w_i is the share of spending at times of use ($i = \{peak, peak\ distributed\ generation, shoulder, off\ peak\}$)

(b) α_i and α_{ri} are national and region-specific averages (constants)

(c) the p_{ij} terms are the price of consuming during each time of use

(d) $\frac{X}{P}$ is total expenditure deflated by a price index on consumption across all four times of use

(e) the term S_{si} represents exogenous demand 'shifters':

(i) an index of hydro storage relative to historical means, with schemes weighted by storage capacity

(ii) an index of national heating degree days, relative to historical averages

(iii) observed annual maximum distributed generation (MW) in any year

26 2010 to 2017 years ended in the month of August.

27 During initial analysis, the data also included measures of consumption of energy produced off-grid during shoulder and off-peak periods (i.e., we considered six categories of demand). However, the presence of very small numbers and many zeros had a significant negative effect on the fit of models on all six categories of demand. Given our primary interest in peak demand, we determined that the results would be more reliable and more useful if off-grid generation was only included for the peak demand period.

(iv) a dummy (binary) variable indicating whether a network reporting area includes New Zealand Aluminium Smelters—used only when estimating the expenditure system for large industrial load

(v) regional labour market earnings (linked employer-employee data from Statistics New Zealand)—used only in the model of distribution-connected demand

(vi) average residential distribution prices (from MBIE's Quarterly Survey of Domestic Electricity Prices, QSDEP)—used only in the model of distribution-connected demand.

2.160 The data is for 2010 to 2017 years ended in the month August (transmission pricing capacity measurement years), by network reporting region divided into two types of consumers:

(a) distribution network connections

(b) load connected directly to the transmission network—for the purposes of our analysis, this includes large industrial loads that are connected to the transmission network at a GXP, via a distributor.

2.161 Separate models are fitted for the distribution-connected and transmission-connected consumer types.

2.162 The model that is estimated is a linear approximation to the "almost ideal demand system" (LA–AIDs). In practice, this means the price index (P) used to deflate total expenditure is a Laspeyres price index, with price changes evaluated relative to shares of expenditure in a base year (w_{0i}):

$$P_t = \sum_{i=1}^{4} w_{i0} \left(\frac{\ln p_{it}}{\ln p_{0t}}\right) \qquad \text{Equation 19}$$

2.163 Estimation of the model requires also adding restrictions to parameter values, based on economic theory. Adding-up constraints (i.e., all expenditure is spent) are enforced automatically by:

(a) estimating the share equations as a system, and

(b) dropping one share equation (also necessary to avoid singularity) during the estimation, and

(c) then inferring parameter values for the share equation that is omitted.

2.164 Table 12 summarises estimated parameters for the LA–AIDs model of demand, by time of use, for:

(a) the model of distribution-connected demand

(b) the model of transmission-connected demand.

2.165 The parameters in Table 12 determine the average elasticities of demand for electricity at the four times of use.

Table 11: LA-AIDS time-of-use parameter values

Coefficient	Time of use	Distribution-connected	Transmission-connected
α	Peak	-0.067	0.081
α	DG peak	0.073	0.004
α	Shoulder	0.307	0.238
α	Off-peak	0.687	0.677
β_1	Peak	0.003	-0.003
β_2	DG peak	-0.009	0.000
β_3	Shoulder	-0.002	-0.002
β_4	Off-peak	0.008	0.004
γ_{11}	Peak, Peak	0.152	0.201
γ_{12}	Peak, Peak DG	0.009	-0.004
γ_{13}	Peak, Shoulder	-0.038	-0.052
γ_{14}	Peak, Off-peak	-0.123	-0.145
γ_{21}	DG peak, Peak	0.009	-0.004
γ_{22}	DG peak, DG peak	0.010	0.008
γ_{23}	DG peak, Shoulder	-0.018	-0.005
γ_{24}	DG peak, Off-peak	-0.001	0.001
γ_{31}	Shoulder, Peak	-0.038	-0.047
γ_{32}	Shoulder, DG peak	-0.018	-0.006
γ_{33}	Shoulder, Shoulder	0.155	0.165
γ_{34}	Shoulder, Off-peak	-0.099	-0.112
γ_{41}	Off-peak, Peak	-0.123	-0.150
γ_{42}	Off-peak, DG peak	-0.001	0.002
γ_{43}	Off-peak, Shoulder	-0.099	-0.109
γ_{44}	Off-peak	0.224	0.256

Source: Electricity Authority

2.166 Table 13 and Table 14 contain examples of these elasticities. Actual elasticities vary by time-of-use expenditure shares. The examples in Table 13 and Table 14 are based on average historical expenditure shares.

Table 12: Demand elasticities for distribution-connected demand
Evaluated at the average expenditure share 2010-2017

Price	**Quantity**			
	Peak	Distributed generation peak	Shoulder	Off-peak
Peak	**-0.49**	0.03	-0.13	-0.43
Distributed generation peak	0.61	**-0.40**	-0.88	0.21
Shoulder	-0.18	-0.09	**-0.23**	-0.49
Off-peak	-0.26	0.00	-0.21	**-0.55**
Expenditure	1.011	0.467	0.991	1.016

Source: Electricity Authority

Table 13: Demand elasticities for direct-connected industrial demand
Evaluated at the average expenditure share 2010-2017

Price	**Quantity**			
	Peak	Distributed generation peak	Shoulder	Off-peak
Peak	**-0.13**	-1.08	-0.29	-0.25
Distributed generation peak	-0.02	**1.33**	-0.03	0.00
Shoulder	-0.20	-1.93	**-0.08**	-0.19
Off-peak	-0.64	0.70	-0.60	**-0.57**
Expenditure	0.988	0.980	0.991	1.007

Source: Electricity Authority

2.167 For the model of transmission-connected demand, the aggregate price elasticity chosen is the all-industry value (-0.02). Though industry-specific elasticities were estimated, using these elasticities is problematic in practice. This is because the geographic areas in our modelling are relatively highly aggregated (14 representative grid nodes) and include a range of different industries in some nodes. Rather than make assumptions about which industry elasticity to apply, we have used the same general industrial elasticity.

2.168 When time-of-use elasticities are calculated, the demand shifters are ignored. In the case of hydrological conditions and heating degree days, this is equivalent to assuming average hydrology and average temperatures.

2.169 In the case of distributed generation capacity, our modelling scenarios involve investment in utility-scale batteries, with distinct impacts on demand at other times of use reflecting the fact that utility-scale batteries change the timing of demand for electricity from non-battery/traditional generation. Thus, the estimated coefficients that dictate impacts of distributed generation capacity on demand are replaced by technical parameters calculated in our analysis of utility-scale battery costs and typical operational characteristics.

Prices

2.170 The demand model considers prices for grid-supplied electricity (prices at the GXP or grid injection point) comprising:

(a) national average generation prices

(b) transport costs (nodal price differences due to losses and constraints)

(c) transmission charges.

Generation prices

2.171 We use a simplified wholesale market dispatch model to produce generation prices. The purpose of the model is:

(a) to allow for feedback effects between demand growth and generation prices

(b) to provide a basis for assessing generation investment decisions.

2.172 In this model generation plant is ‘dispatched’ according to merit order (ranking) of generation plant offers. Prices are calculated, for each of the model’s four times of use, by observing the price in the aggregate (market) offer curve that aligns with the amount of generation (MW) required to serve demand. The price for each time of use is the expected average annual price for that time of use.

2.173 The shape of generation plant offer curves is fixed using offers in calendar year 2020 for each plant and averaging over only those periods in which capacity was offered, to capture potential output.

2.174 Offers by existing generation plant are used to model future offers from existing generation plant. Offer curves for new generation investments are based on offer curves of comparable existing generation plant.

2.175 The offer curves that are used in the model reflect actual market offers with five quantity-price pairs for offers (or bands). Offer prices are adjusted so that no offers are made below short run marginal cost. While offers often include prices below marginal cost, this adjustment is necessary so that prices cannot fall below marginal cost if there is a demand shock such as closure of NZAS.

2.176 For wind farms, offer data is available from 2020 but it is generally uninformative with the full capacity of plant offered for near zero price. In order to capture more cost reflective offers in future if wind is a large share of supply we assume that all offers are at short run cost (approximately $3 per MWh) but that offers in the highest band during peak and shoulder periods are set at long-run marginal cost to cover the possibility that wind is the marginal price setting plant.

2.177 All offers by new investments, including solar farms, follow the same pattern as for wind, with plant offered at long run marginal costs in the highest price bands during peak and shoulder periods and otherwise offered at short run marginal costs.

2.178 For new investments in wind generation, average MWh of generation is based on an assumed 39.4% capacity factor (output relative to capacity) and this value is assumed to apply to off-peak demand periods. Output is assumed to be 0.9% lower during peak periods (a capacity factor of 38.5%) and 0.68% higher during shoulder periods (a capacity factor of 40.8%). These capacity factors are based on observed wind generation output (wholesale market generation data) by time of use over 2007-2020.

2.179 Capacity offered by solar farms, by time of use, is based on potential generation given average solar radiance during times of use. Overall potential capacity factors of solar farms are based on estimates in MBIE's 2020 generation stack updates.

2.180 The Guidelines CBA included adjustment factors to account for diversity of demand and offers. That is, the sum of average MW offered by generation plant, individually, will understate the average aggregate market MW offered, due to a positive correlation between capacity offered by individual generation plant, by trading period. These adjustments are not used in this CBA because the modelled offer curves, based on volumes offered only when offering, sufficiently reflect potential output and produce modelled prices for 2021 that are similar to prices observed in 2020 that there is no need for model calibration.

2.181 Offer curves have been adjusted to account for distributed generation during shoulder and off-peak periods. The model does not otherwise account for distributed generation. The adjustment consists of increasing volumes offered by existing generation plant by 6.5% and 8.5% in shoulder and off-peak periods respectively. No such adjustment is needed at peak as demand for DG at peak is considered explicitly.

2.182 Generation offer curves are shifted up or down as short-run marginal costs change, thus capturing the effects of changes to operating costs (e.g., from increases in gas prices and emissions prices).

2.183 Generator earnings are calculated as part of the dispatch process. Earnings are the surplus of generator revenue (market price multiplied by dispatched quantities) less short-run operating costs (short-run marginal costs multiplied by dispatched quantities). This provides a measure of market surplus attributable to producers (producer surplus), excluding fixed costs (where fixed costs include capital rental costs and fixed interconnection charges).

Transport costs

2.184 Transport costs are modelled as a function of:

(a) average historical price differences at each backbone node from average national generation prices (LCE)

(b) growth in demand, which is assumed to increase price differentials.

2.185 Three types of transport costs are considered:

(a) average LCE during all trading periods

(b) average LCE during periods of local resource scarcity (when demand exceeds generation at the backbone node)

(c) average LCE during periods of local resource abundance (when generation exceeds demand at the backbone node)

2.186 This ensures the model takes account of:

(a) nodes having periods with positive transport costs and periods with negative transport costs (net generation or net load), and thus

(b) the extent to which backbone nodes, and generators and consumers, are beneficiaries of the transmission network.

2.187 Transport costs are also differentiated across peak, shoulder and off-peak periods.

2.188 For reasons of tractability the demand model does not adjust transport costs in response to transmission investment. As a result, transport costs increase whenever demand increases and do not decline unless demand declines. The effects of transmission investment on transport costs are analysed outside the demand model. (See the section above on the effect of changes in transmission investment costs and benefits on more efficient grid use—starting at paragraph 2.46)

2.189 We estimated a model summarising the effects of an increase in demand on transport cost (LCE) mark-ups over generation costs (prices received by generators). The conceptual basis for the model is that energy losses and constraints are an increasing function of demand. Empirically, the relationship is expected to be conditional on:

(a) year-specific differences in grid configuration and assets

(b) node-specific differences in load management

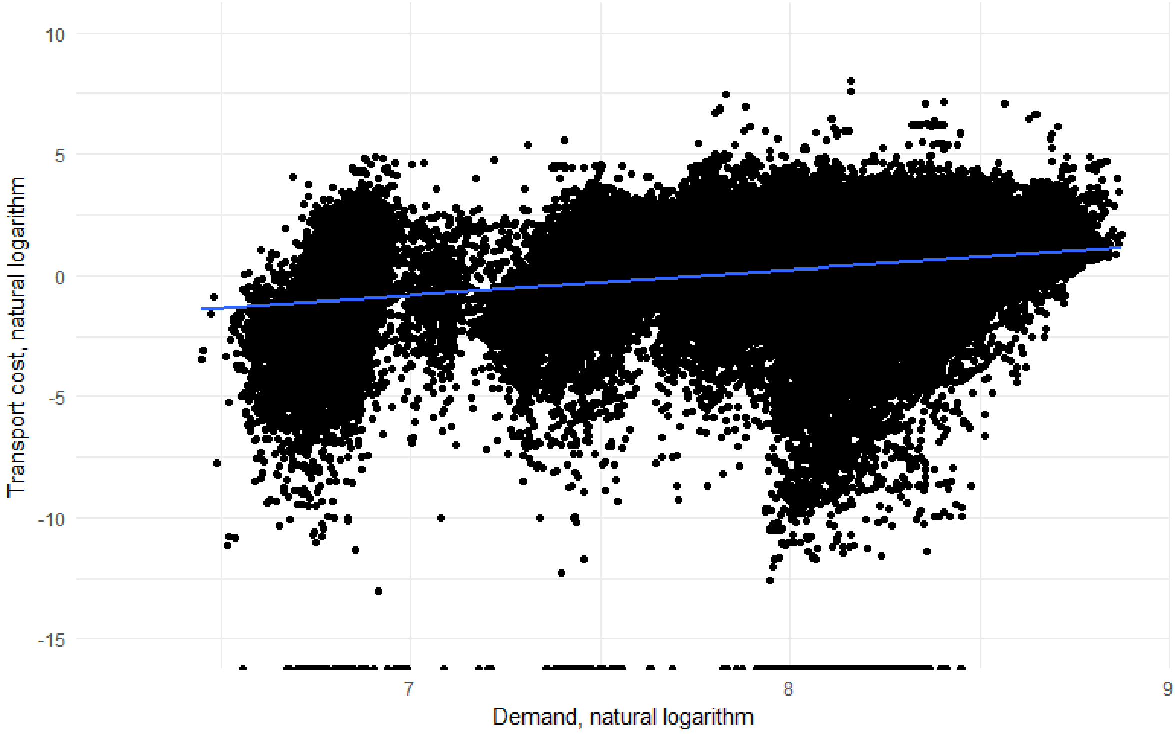
(c) capacity utilisation of the HVDC being constrained

(d) availability and cost of generation

(e) availability of distributed generation.

2.190 Without conditioning on other factors, data shows a positive relationship between demand and transport costs over time. However, the relationship is not strong (see Figure 3).

Figure 3: Relationship between demand and transport costs
Observations by backbone node and trading period, 2007–2018



Source: Electricity Authority

2.191 The model that is estimated is:

$$l_{it} = \alpha_i + \delta_t + x_{it} + g_{it} + u_t + p_{it} + d_{it} \qquad \text{Equation 20}$$

2.192 Where

(a) l is LCE by back-bone node and trading period (indices i, t respectively) per MWh

(b) α_i and δ_t are locational (back-bone node) and year-specific fixed effects (means)

(c) x_{it} is metered grid exports (demand)

(d) g_{it} is generation

(e) u_{it} is utilisation of the HVDC (flows relative to maximum capacity)

(f) p_{it} is price received by generators

(g) d_{it} is distributed generation.

2.193 All variables are transformed by natural logarithms.

2.194 Two variants of the model are estimated:

(a) one for periods and locations where transport costs are positive and generation at a node is scarce (load exceeds generation)

(b) one for periods and locations where transport costs are negative and generation is not scarce (generation exceeds load).

2.195 In the model of negative transport costs, the LCE value is the absolute value.

2.196 The model results, shown in Table 15 and Table 16, indicate that the elasticity of transport costs with respect to an increase in demand are 0.13 for situations of positive transport costs and -0.05 for situations of negative transport costs.

Table 14: Model of transport costs
Dependent variable is natural logarithm of LCE per MWh

Term	Coefficient	Standard error	T statistic	P value
Intercept	-0.35	0.0206	-16.9	0.000
BPE	-0.97	0.0087	-110.5	0.000
HAY	-1.63	0.0105	-155.1	0.000
HLY	-0.18	0.0091	-19.9	0.000
ISL	-0.44	0.0103	-43.1	0.000
KIK	-0.40	0.0097	-41.4	0.000
MDN	-0.01	0.0099	-1.5	0.143
OTA	-0.30	0.0116	-26.1	0.000
RDF	-0.87	0.0099	-88.1	0.000
ROX	0.19	0.0086	21.7	0.000
SFD	-0.84	0.0086	-97.2	0.000
TRK	-0.63	0.0092	-68.5	0.000
TWI	0.27	0.0097	27.9	0.000
WKM	0.02	0.0101	1.5	0.127
2010	-0.17	0.0095	-18.1	0.000
2011	-0.17	0.0095	-18.1	0.000
2012	0.25	0.0100	25.1	0.000
2013	-0.09	0.0096	-9.0	0.000
2014	-0.41	0.0096	-42.8	0.000
2015	-0.65	0.0096	-68.1	0.000
2016	-0.41	0.0096	-42.9	0.000
2017	-0.19	0.0097	-19.4	0.000
x	0.13	0.0027	48.1	0.000
g	-0.20	0.0019	-106.0	0.000
u	0.34	0.0014	252.8	0.000
p	0.73	0.0019	383.9	0.000
d	-0.0004	0.0001	-3.8	0.000

Source: Electricity Authority

Table 15: Model of negative transport costs

Dependent variable is natural logarithm of absolute value of LCE per MWh

Term	Coefficient	Standard error	T statistic	P value
Intercept	-2.29	0.02	-97.26	0.00
BPE	-0.67	0.01	-83.36	0.00
HAY	-0.78	0.01	-79.77	0.00
HLY	-0.29	0.01	-35.85	0.00
ISL	0.20	0.01	18.68	0.00
KIK	0.35	0.01	30.07	0.00
MDN	-0.20	0.01	-14.09	0.00
OTA	-0.06	0.01	-5.61	0.00
RDF	0.15	0.01	16.31	0.00
ROX	0.31	0.01	50.18	0.00
SFD	-0.47	0.01	-67.62	0.00
TRK	0.01	0.01	0.88	0.38
TWI	0.39	0.01	52.46	0.00
WKM	-0.30	0.01	-35.65	0.00
2010	-0.19	0.01	-17.86	0.00
2011	-0.20	0.01	-18.79	0.00
2012	0.40	0.01	36.41	0.00
2013	-0.01	0.01	-1.13	0.26
2014	-0.34	0.01	-31.04	0.00
2015	-0.54	0.01	-49.63	0.00
2016	-0.38	0.01	-34.64	0.00
2017	-0.15	0.01	-13.80	0.00
x	-0.05	0.00	-20.71	0.00
g	0.16	0.00	64.28	0.00
u	0.19	0.00	134.62	0.00
p	0.80	0.00	377.21	0.00
d	0.00	0.00	-27.12	0.00

Source: Electricity Authority

Transmission charges

2.197 Transpower's forecast revenue comprises:

(a) Transpower's base capex

(b) Transpower's listed projects[28]

(c) Transpower's approved major expenditure.

2.198 The demand model implements four methods for recovering transmission interconnection revenue (inclusive of overheads but excluding connection charges, which are not included anywhere in the model):

(a) benefit-based charges on load and generation

(b) RCPD charges on load

(c) SIMI charges on South Island generation

(d) residual charges.

2.199 Benefit-based charges are allocated as discussed above in paragraphs 2.50 to 2.57 and residual charges are allocated based on based on an initial AMD allocation and adjusted over time for growth in consumption.

2.200 SIMI charges are based on shares of the previous five years' average generation for South Island generators (grid-connected generators only).

Price expectations

2.201 In the demand model consumers are assumed to choose their demand for electricity based on their expectations of wholesale energy prices and transmission interconnection prices (i.e., electricity prices inclusive of transmission interconnection charges).

2.202 In the model we assume consumers' expectations of wholesale energy prices are based on the average of:

(a) the prior two periods' wholesale market prices, and

(b) the dispatch price calculated from the prior year's wholesale market offer curves and national demand, by time of use, where national demand is equal to the prior year's national demand multiplied by the rate of exogenous demand growth.

2.203 We use an average to account for the fact that energy prices can be volatile and mean-reverting (a high price last period is likely to be followed by a downward correction in the next period).

2.204 Consumers' expectations of transmission interconnection prices are based on their most recent transmission interconnection charges, combined with information about future

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28 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 capex projects that:

(a) Transpower expects to commission during the regulatory control period, and

(b) must follow the same process for approval as a major capex 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 capex 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.

growth in these charges based on forecast transmission revenue (in the case of interconnection charges that change over time).

2.205 In the case of coincident peak demand charges, consumers do not know for certain what their charges will end up being, as these are only determined after all consumers have made their consumption decisions (in the model and in practice). Ex-post balancing is undertaken to ensure that all transmission revenue is recovered (as happens in practice). However, consumers will not perceive their actual transmission interconnection price until the next year when they recalibrate their expectations.

Model 2: Generation investment model

2.206 Generation investment is modelled using a schedule of potential generation investments based on MBIE's 2020 generation stack update and selecting the lowest cost investments, subject to expected average revenue in the first year of a new generation investment being equal to or larger than annualised long-run marginal generation costs plus expected interconnection charges.

2.207 Expected average revenue in the first year of a new generation investment is based on adding the new investment's offer curves to the previous year's wholesale market offer curves and calculating nodal prices based on the previous year's demand.

2.208 This simplified model of investment decision-making, which has investors requiring an immediate positive return on their investment, is consistent with investors ignoring the possibility that wholesale energy prices will rise in the future. We consider it reasonable to assume investors would take this approach, on the grounds that the future is inherently uncertain—for example, the investment's profitability might be undermined by wholesale prices declining, by negative demand growth shocks, or by technology shocks.

2.209 Expected interconnection charges are based on the previous year's average interconnection charge ($/MWh) at the node where the new generation investment is occurring, adjusted for the effect that a new generation investment would have on those average charges (by sharing the amount of interconnection charges collected in a region over more beneficiaries).

2.210 As summarised in Table 2, the model includes significant declines in the capital costs of intermittent renewables, increasing operating costs of thermal plant, and a ban on new thermal generation from 2030. These factors point to rapidly increasing shares of intermittent renewables.

2.211 A future with high penetration of renewables poses significant challenges, when viewed through the lens of existing market dynamics. Some of these challenges are the subject of active discussion and debate, such as:

(a) the need for thermal plant to remain available to stabilise supply in a market with high penetration of intermittent renewables, particularly during peak periods

(b) how wholesale prices will be set in a market with abundant supply of generation with low operating costs

(c) the scale and types of energy storage that will be needed to ensure that supply can meet growing demand.

2.212 These sorts of challenges carry over into any modelling of future electricity supply and demand and thus affect the modelling used for the TPM CBA where we assume that wind and solar will become much cheaper than alternative resources and when demand is assumed to grow rapidly as the economy electrifies.

2.213 The need for increased storage is accommodated by assuming that wind farms and solar farms can be constructed with batteries. In practical terms this means increasing the potential output of wind and solar investments during peak periods, at a cost in terms of reduced efficiency (losses) and higher capital costs.

2.214 This approach approximates the effect that increased investment in battery storage will have on market dynamics – shifting energy from high production periods to high demand periods but at a cost – and greatly simplifies modelling as compared to explicitly modelling investment in utility scale storage.

2.215 To model the effect of batteries on shifting wind and solar farm output we use estimates of typical rates of energy arbitrage across trading periods from our model of battery operation and investment (see paragraph 2.232 below). The model, based on historical prices and demand, produces optimised charging and discharging rates by time of use and ratios of inputs to outputs (discharge to charge ratios). These ratios of inputs to outputs are used to adjust solar and wind capacity factors to mimic the effects of battery storage. The average capacity factors used in the model are summarised in Table 17.

Table 16 Wind and solar capacity factors with and without batteries

	Peak	Shoulder	Off-peak	Total
Ratio of MW charge: discharge	1.88	1.07	0.74	0.88
Wind capacity factors	0.39	0.41	0.39	0.39
Wind with batteries	0.73	0.44	0.29	0.35
Solar capacity factors	0.11	0.26	0.17	0.18
Solar with batteries	0.20	0.28	0.13	0.16

Source: Electricity Authority

Model 3: Model of investment in distributed energy resources (batteries)

2.216 We have modelled investment in distributed generation or other distributed energy resources, using the specific example of investment in utility-scale batteries. For the purposes of the modelling, we treat these investments as demand-side investments.

2.217 Decisions to invest in utility-scale batteries are based on a model of the optimal amount of battery capacity in a transmission pricing region. The optimal amount of battery capacity is found by equating marginal present-valued earnings (revenue less variable operating costs) with marginal present-valued capital costs (inclusive of fixed operating costs).

2.218 Earnings on utility-scale battery investment are assumed to be a declining function of the amount of battery capacity installed (i.e., decreasing marginal returns) and an increasing function of peak demand charges.

2.219 A simulation model is used to estimate earnings from utility-scale battery investment by transmission pricing region. It takes a fixed amount of battery investment (in MW) and uses a linear programme to find the timing and scale of battery charging and discharging that maximises earnings. By running multiple simulations, varying the amount of battery investment (MW) in each simulation, the model produces a data set that describes the relationship between:

(a) earnings from battery investment, and

(b) the scale of battery investment and peak demand charges.

2.220 Earnings calculated using the simulation model are then adjusted to account for the potential effects of battery operation on wholesale energy prices by trading period. That is, as battery investment increases and load curves are flattened, we would expect energy price arbitrage opportunities to diminish as high prices fall and low prices rise. To capture this effect, we assume that a 1% change in grid energy demand causes a 2% change in prices.[29]

2.221 Earnings functions are then constructed. The natural logarithm of average earnings (e_z) per MW (x) by pricing zone (z) from the simulation model results is expressed as a polynomial of the natural logarithm of the amount (MW) of utility-scale batteries installed and the interconnection rate (ic):

$$e_z = \exp(c_{z1} + c_{z2}\log(x) + c_{z3}\log(x)^2 + c_{z4}\log(x)^3 + c_{z5}\log(x)^4 + c_{z6}\log(x)^5 + c_{z7}.ic) \qquad \text{Equation 21}$$

2.222 The coefficients (c_{zi}) are estimated using ordinary least squares with year fixed effects.

2.223 Costs of investing in utility-scale batteries are similarly characterised by a polynomial. Costs in dollars per MW (c) are expressed as a function of the year (y) of investment:

$$c_y = c_1 + c_2 y + c_3 y^2 + c_4 y^3 + c_5 y^4 \qquad \text{Equation 22}$$

2.224 The linear programming model used to simulate earnings is adapted from Davies et al (2019).[30] The linear programming model determines optimal battery operation cycles (charging and discharging).

2.225 Optimal operation is simulated, for each transmission pricing region, over each trading period between 1 September 2014 and 31 August 2017. The simulation model optimises hourly operation on a daily basis, with links between days created by tracking the amount of energy stored in batteries at the end of each day. Energy prices and demand are exogenous and are based on actual wholesale electricity market demand and prices by trading period. Interconnection charges are based on calculating RCPD charges using 100 trading periods and revenue requirements.

2.226 The main adaptation of the model in Davies et al (2019) is to restrict battery operation to account for the effects that charging and discharging of batteries has on regional coincident peak demands and transmission interconnection prices. This includes the following adjustment to account for uncertainty in predicting RCPD periods:

- upper bound on **charging** is held at zero where forecast regional grid export is within 2% of minimum observed RCPD, to represent load forecasting errors
- upper bound on **discharging** is held at zero where forecast regional grid export is a peak period and within 2% of minimum RCPD.

29 This assumption is informed by a simple linear regression of the natural logarithm of prices on a 3rd order polynomial of demand by trading period between 2010 and 2017 with year fixed effects. The fitted values from that model show the average percentage change in prices is twice the percentage change in demand.

30 Davies, D.M., Verde, M.G., Mnyshenko, O., Chen, Y.R., Rajeev, R., Meng, Y.S., Elliott, G., 2019. Combined economic and technological evaluation of battery energy storage for grid applications. Nature Energy 4, 42. https://doi.org/10.1038/s41560-018-0290-1

2.227 To determine the optimal scale of battery investment, there are also:

- upper bounds on charging per trading period equal to the difference between forecast minimum RCPD and forecast regional grid export, assuming perfect knowledge
- upper bounds on discharging during peak demand periods equal to the difference between forecast regional grid export and forecast minimum RCPD, assuming perfect knowledge.

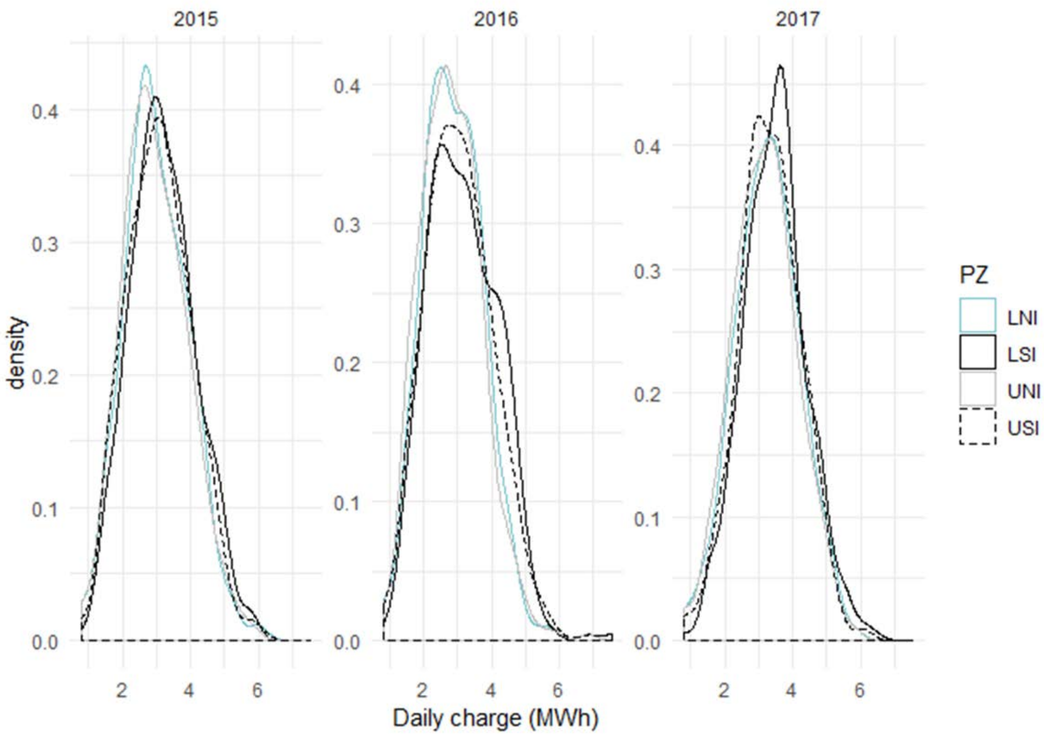
2.228 The simulation model (and our analysis of battery costs) assumes that:

- batteries have a maximum operating range of 10% to 90% of maximum capacity (a state of charge of between 0.1 and 0.9 of capacity)
- all batteries have an energy-to-power ratio of 1 (a 1 MW / 1 MWh battery)
- energy losses of 10% occur during battery operation.

2.229 The simulation model shows significant variation, within a year, of daily battery cycling. Figure 4 shows the distribution of daily charging in MWh for a 1 MWh battery with unit energy to power ratio and operating limits of 10%–90% of battery charge. Average daily discharge is 2.8 MWh per day and average daily charge is 3.1 MWh per day (the difference being losses).

Figure 4: Modelled battery cycles, baseline

PZ is transmission pricing region: Upper North Island (UNI), Lower North Island (LNI), Upper South Island (USI), Lower South Island (LSI)



Source: Electricity Authority

2.230 Battery profitability is highest at low levels of total investment (see Table 17). Battery profitability is constrained, as the amount of batteries increases, because of:

- a narrowing of differences across wholesale energy prices (high prices fall and low prices rise)[31]
- fewer opportunities to flatten load, to avoid peak demand charges.

2.231 Batteries are substantially more profitable with RCPD charges than without RCPD charges and earnings are highest in areas with the peakiest load.

Table 17: Modelled average annual earnings per MW invested ($)[32]

	Without RCPD charge, by pricing zone				With RCPD charge, by pricing zone			
MW	UNI	LNI	USI	LSI	UNI	LNI	USI	LSI
1	26,756	25,175	24,455	22,224	53,827	64,211	39,317	20,832
5	26,513	24,968	24,169	21,997	51,721	62,371	35,575	20,378
10	26,210	24,710	23,813	21,713	50,007	59,654	32,415	19,891
20	25,604	24,193	23,099	21,144	46,752	55,645	28,217	18,975
50	23,785	22,644	20,960	19,438	39,785	45,567	23,193	16,917
100	20,754	20,061	17,394	16,595	32,491	35,538	18,290	14,123
200	14,692	14,895	10,262	10,909	23,109	24,537	10,901	9,916
300	8,629	9,729	3,130	5,223	15,144	16,222	5,428	7,184
400	2,567	4,564	-4,002	-463	8,110	9,669	1,428	5,064
500	-3,495	-602	-11,105	-6,149	2,125	4,414	-1,383	3,333

Source: Electricity Authority

2.232 The simulation model is also used to provide estimates of the net effects of utility-scale battery operation on grid-level demand, by time of use. This is done by noting time of use (being the grid use model's four times of use) prior to the simulation of battery operation and then calculating changes in demand by time of use.[33]

2.233 This calculation indicates that, in the presence of RCPD charges, one MW of batteries causes, on average:

- 100 MWh reduction in peak grid demand

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31 The modelling assumes a price elasticity of supply of 2—a 1% change in demand is assumed to change wholesale energy prices by 2%. This assumption was informed by analysis of correlations between changes in demand and changes in wholesale energy prices.

32 Numbers in this table include losses due to ex-post price adjustment. Daily cycle optimisation does not permit losses.

33 The effects of battery operation on grid-level demand are subject to index number problems in the sense that the effects of battery operation on demand by time of use depends on whether the change in demand is measured with reference to demand before or demand after batteries are introduced.

- 100 MWh increase in peak non-grid demand
- 22 MWh reduction in shoulder demand
- 222 MWh increase in off-peak demand.[34]

2.234 These numbers reflect changes in traded volumes of energy and amount to a 199 MWh net change in the amount of energy traded. The change in final consumption demand is zero. There is a net increase in grid supply/demand of 99 MWh, reflecting energy lost during battery charging and discharging.

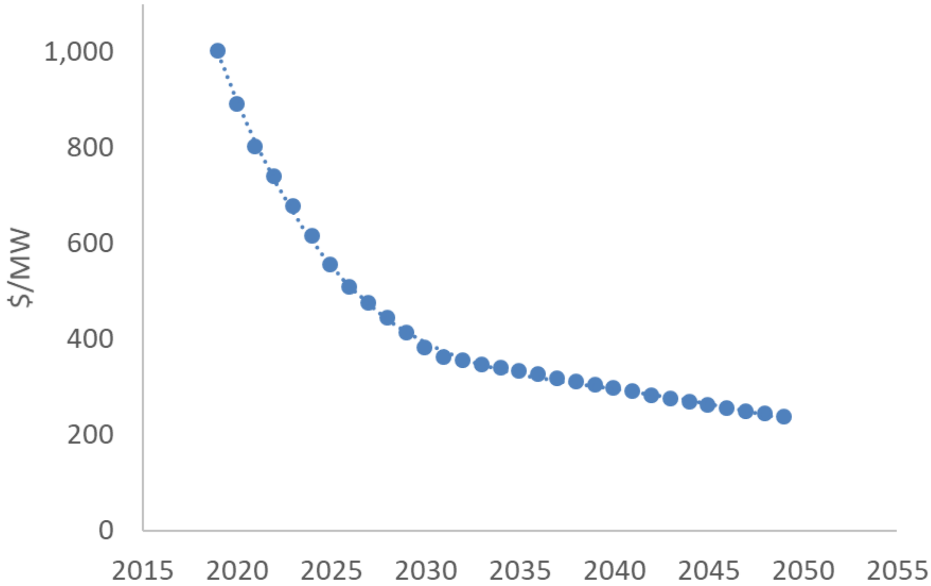
2.235 As noted above, the battery investment model is focussed on optimal investment by transmission pricing region. We have used each backbone node's historical average share of grid demand in the transmission pricing region in which the backbone node is located to determine each backbone node's share of utility-scale battery investment.

2.236 Battery investment cost assumptions reflect recent international research reports and analyses of current and expected battery costs.[35] Figure 5 summarises the central projection for battery investment costs (present-valued costs per MW).

2.237 Our assumed costs include upfront capital and connection costs and the present value of ongoing operating and maintenance costs (fixed at 2.5% of capital costs).

Figure 5: Battery investment cost assumption

Present value cost ($/MW) for a 1 MW battery with energy to power ratio of 1 (1 MWh battery)



Source: Electricity Authority

[34] These are net numbers—the net of charging which increases grid demand and discharging which reduces grid demand.

[35] See Schmidt, O., Melchior, S., Hawkes, A., Staffell, I., 2019. Projecting the Future Levelized Cost of Electricity Storage Technologies. Joule 3, 81–100. Refer also National Renewable Energy Laboratory, 2019 Annual Technology Baseline and Cole, W. and Frazier, A. W., National Renewable Energy Laboratory, June 2019, Cost Projections for Utility-Scale Battery Storage.

Options/variants of the proposal

2.238 The grid use model projects electricity demand and costs (prices) for the period 2021 to 2049, for each of the three proposed options and the baseline. Results for the four are then compared, and consumer welfare changes or cost differences are calculated.

2.239 The following variants have been modelled:

(a) Central – 47:53 percent sharing of benefit-based charges between generators and load under the simple method, overhead opex recovered through benefit-based charges

(b) Simple method, review 75:25 – as for the central except a five-year review leads to a change to a 75:25 percent allocation of benefit-based charges between load and generators under the simple method, but otherwise the same settings as the central scenario

(c) Simple method, 75:25 – as for the central except the proposed TPM commences with a 75:25 percent allocation of benefit-based charges between load and generators under the simple method

(d) BBCs exclude overhead opex – overhead opex is recovered through the residual charge, but otherwise the same settings as the central scenario.

Assessing the transitional cap on transmission charges

2.240 The quantified impact of the transitional cap on transmission charges in the proposed TPM has been carried over from the estimate used in the Guidelines CBA. That estimate was based on the incremental cost to consumers facing increased charges to cover revenue caps (i.e. allocative efficiency costs from discouraging consumption through increased prices).

2.241 The cost of the transitional cap estimated for the Guidelines CBA was not large ($1 million), in the overall scheme of things. And the amount of costs redistributed due to the price cap is expected to be lower under the proposed TPM compared to what was anticipated in the 2020 Decision paper for the TPM Guidelines (a reduction of $2.3 million). As such, retaining the estimate from the Guidelines CBA, as an indicative estimate of the cost of the price cap, may overstate the costs of the cap. But because the estimated cost is not large the effect of any overstatement will be immaterial.

Other key assumptions in modelling more efficient grid use

2.242 We have made a number of key assumptions in our modelling of more efficient grid use. Key assumptions not set out earlier in this section are set out below.

Population growth assumptions

2.243 Population growth parameters used in the CBA are from medium population projections produced by Statistics New Zealand, aggregated to backbone nodes. Other scenarios (low and high) can also be used by setting parameters in the model. These parameter assumptions translate directly into growth in numbers of ICPs. Table 18 sets out our assumptions for the low and high population growth rate scenarios.

Table 18: Population growth rate scenarios

Backbone node	Medium	Low	High
MDN	0.7%	0.2%	1.1%

Backbone node	Medium	Low	High
OTA	1.1%	0.6%	1.5%
HLY	0.9%	0.4%	1.3%
TRK	0.8%	0.3%	1.2%
WKM	0.4%	-0.1%	0.9%
RDF	0.5%	0.0%	1.0%
SFD	0.4%	-0.1%	0.9%
BPE	0.4%	-0.1%	0.9%
HAY	0.5%	0.0%	1.0%
KIK	0.4%	-0.2%	0.8%
ISL	0.7%	0.2%	1.2%
BEN	0.6%	0.1%	1.1%
ROX	0.1%	-0.4%	0.6%
TWI	0.2%	-0.3%	0.8%

Source: Electricity Authority

Income growth assumptions

2.244 Our default assumption is that national per capita income growth (real) is 1% per annum, from which we derive income growth parameters by backbone node using the factors set out in Table 19.

Table 19: Assumed income growth by area, relative to national rate

Backbone node	Value
MDN	0.999
OTA	0.999
HLY	1.010
TRK	1.000
WKM	0.980
RDF	0.997
SFD	0.994
BPE	0.994
HAY	0.998
KIK	1.027
ISL	1.001
BEN	1.020
ROX	0.992
TWI	1.007

Source: Electricity Authority

Other key assumptions or parameters

2.245 Table 20 contains other key assumptions used in the CBA that are not stated elsewhere in this document.

Table 20: Other key assumptions or parameters in modelling of efficient grid use

Assumption / Parameter	Value
Social discount rate (real)	6%
Initial share of benefit-based charges:	
Generation, backbone node BEN	0.1380
Generation, backbone node BPE	0.0117
Generation, backbone node HAY	0.0018
Generation, backbone node HLY	0.0103
Generation, backbone node ISL	0.0053
Generation, backbone node KIK	0.0010
Generation, backbone node MDN	0.0000
Generation, backbone node OTA	0.0000
Generation, backbone node RDF	0.0048
Generation, backbone node ROX	0.0765
Generation, backbone node SFD	0.0135
Generation, backbone node TRK	0.0008
Generation, backbone node TWI	0.0862
Generation, backbone node WKM	0.0564
Mass market, backbone node BEN	0.0110
Mass market, backbone node BPE	0.0144
Mass market, backbone node HAY	0.0423
Mass market, backbone node HLY	0.0317
Mass market, backbone node ISL	0.0567
Mass market, backbone node KIK	0.0112
Mass market, backbone node MDN	0.0336
Mass market, backbone node OTA	0.2591
Mass market, backbone node RDF	0.0108
Mass market, backbone node ROX	0.0087
Mass market, backbone node SFD	0.0122
Mass market, backbone node TRK	0.0103
Mass market, backbone node TWI	0.0089
Mass market, backbone node WKM	0.0002
Large industrials, backbone node BPE	0.0038
Large industrials, backbone node HLY	0.0029
Large industrials, backbone node ISL	0.0010

Assumption / Parameter	Value
Large industrials, backbone node OTA	0.0126
Large industrials, backbone node RDF	0.0033
Large industrials, backbone node SFD	0.0020
Large industrials, backbone node TRK	0.0021
Large industrials, backbone node TWI	0.0548

Source: Electricity Authority

Key sensitivities analysed in modelling of more efficient grid use

2.246 We have undertaken a sensitivity analysis on key input assumptions that can significantly affect the results of our modelling of benefits from more efficient grid use.

2.247 The results of the grid use model are sensitive to the timing and size of changes in underlying costs of, and demand for, electricity. To account for this, the CBA considers the range of results produced by the grid use model for different policy options, through variations to the model's input assumptions about future[36]:

- **short-run costs** of operating electricity generation
- **long-run costs** of investing in electricity generation
- **underlying electricity demand growth** driven by growth in population and incomes
- **NZAS closure**.

2.248 We weight the results of different simulations as it is important to avoid treating highly unlikely results the same as more likely results. As such, our approach involves:

- specifying ranges for the model's key input assumptions
- simulating model results for each of the policy scenarios:
  - o the baseline
  - o the proposal central scenario
  - o the proposal with simple method allocation of 75:25 after the first five year review
  - o the proposal with simple method allocation of 75:25 from the outset
  - o the proposal with benefit-based charges excluding overhead opex
- weighting the model results by the relative likelihood of combinations of input assumptions.

The approach is similar to, but simpler than, Monte Carlo analysis

2.249 This approach has similarities to Monte Carlo analysis, a widely used modelling method where a model is simulated thousands of times, with input assumptions drawn randomly from pre-defined probability distributions. Results obtained from Monte Carlo analysis can be thought of as providing a probability distribution over outcomes.

36 The Guidelines CBA tested the sensitivity of results to changes in assumptions about costs of utility scale batteries. That analysis showed that results are not very sensitive to this assumption. Consequently that sensitivity has not been repeated.

2.250 Applying Monte Carlo analysis to each of the policy scenarios listed above is impractical, primarily because of the amount of data generated. In particular, a simulation for each policy scenario produces 500 MB of data, and 1,000 simulations of a policy scenario (which would take 12 days to complete) would produce 500 GB of results.

2.251 Instead, we took the approach of fitting probability distributions to the input assumptions and then assessing the **relative** likelihood of combinations of input assumption values, as if these values have been drawn randomly. Weighting the grid use model's results by the relative likelihood of each of the model's input assumptions provides a simpler means of reflecting a probability distribution over the model's results.

Ranges of input assumptions

2.252 We carried out model simulations using 100 different combinations of input assumptions in addition to the input assumptions for the 'central scenario' of the proposal. These 100 simulations were chosen to capture a reasonable range of possible input assumption values, while also limiting the number of simulations for practical reasons.

2.253 The ranges of input assumption values we have used are as follows:

- electricity generation short-run cost growth multiplier: 0.990, 0.995, 1.000, 1.005, 1.010
- electricity generation long-run cost growth multiplier: 0.990, 0.995, 1.000, 1.005, 1.010
- electricity demand growth shifter: 0.000, -0.005
- NZAS year of closure: 2024, 2099.

2.254 The cost multipliers are cumulative with the multiplier applied each year on top of prior years' increases or decreases. For example, after 28 years a short run cost multiplier of 1.01 (or 1% additional growth) increases short run costs by 32% compared to the central scenario.

2.255 The demand growth shifter is applied as an addition to growth rates for national per capita income and number of ICPs (a proxy for population). A value of -0.005 for the demand growth shifter reduces growth in both per capita incomes and ICPs by 0.5% per year.

2.256 High rates of demand growth have not been tested as the NZAS closure scenarios provide for alternative growth rate scenarios with higher growth rates in the long run when NZAS closes in 2024 as compared to if NZAS remains open (closure year of 2099).

Probabilities for input assumptions

2.257 The probability distributions for our input assumptions are based on the values used in the Guidelines CBA which were constructed by:

- identifying long-term historical data series that reflect our input assumptions
- deflating any price indices by economy-wide inflation (Statistics New Zealand's GDP deflator)
- de-meaning these series

- fitting distributions to de-meaned data based on graphical analysis and comparison of the fit of the data to commonly used probability distributions[37]
- analysing correlations between the series, to determine whether or not the probability distributions should be treated as independent probabilities.

2.258 The method used to vary cost assumptions differs from that used in the Guidelines CBA because it is based on growth rates that have a cumulative effect rather than a once and for all shift in costs, up or down. We use the same probability distributions for weighting the assumptions as were used in the Guidelines CBA but choose a single year (15 years into the future) in which to evaluate the relative probability of an assumption.

Short-run generation costs

2.259 We modelled variations in short-run generation costs using data on input costs from Statistics New Zealand's Producer Price Index for inputs into the electricity and gas supply industries.

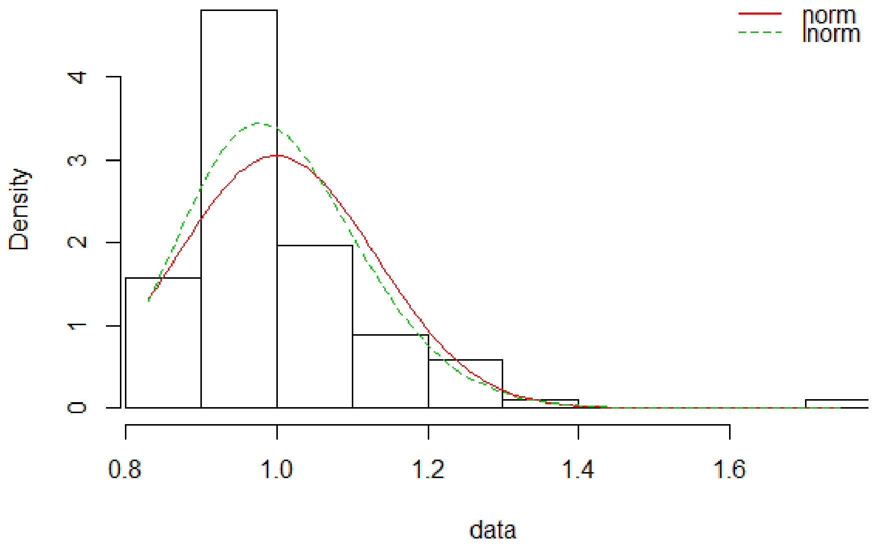
2.260 MBIE data on inflation-adjusted wholesale gas prices was also considered as a source of data on short-run generation costs. We decided not to use this data because:

- it excludes non-fuel short-run generation costs, and
- gas prices exhibit significant structural changes not reflected in broader price indices.

2.261 The probability distribution with the best fit to the data was a log-normal distribution with a log mean of -0.007 and a log standard deviation of 0.117. This distribution has a long right-hand tail, meaning that higher values are more likely than lower values. This is shown in Figure 6. The data in the plot are typical rates of increase after de-trending the data (deducting the average growth rate).

Figure 6: Distribution of changes in short-run costs

Data and fitted distributions: norm = Normal, lnorm=lognormal



Source: Electricity Authority

[37] For example: normal, uniform, exponential, logistic, beta, lognormal and gamma. Utility-scale battery costs are an exception, as there is no obvious candidate data series for fitting distributions. Accordingly, battery investment cost assumptions are assumed to be equally likely (uniformly distributed).

Long-run generation costs

2.262 We modelled variations in long-run generation costs using data on capital costs from Statistics New Zealand's Capital Goods Price Index (CGPI) for all capital goods.

2.263 Other capital goods price indices that we considered were:

- civil construction
- plant, machinery and equipment
- engines and turbines
- electric motors, transformers and generators
- electricity distribution and control apparatus
- an average of civil construction and plant, machinery and equipment indices.

2.264 There are strengths and weakness in using any of these series to characterise long-run generation investment costs.

2.265 No single index can capture all relevant investment costs for electricity generation. This is because some generation investment projects are dominated by civil construction costs (e.g., a large-scale hydro generation project), while other projects are dominated by plant machinery and equipment costs (e.g., an investment in a thermal peaking plant).

2.266 Furthermore, costs for plant, machinery and equipment have been declining steadily over the past 15 years (-20% between 2004 and 2019) relative to general inflation in the economy, while civil construction costs have been rising (+15% between 2004 and 2019). As such, a decision to use either one of these indices over the other would significantly affect the assessed rate of increase in generation investment costs.

2.267 We chose the CGPI for all capital goods, over any particular sub-group of costs, as it:

- captures other capital costs (such as buildings) of some relevance to generation investment
- is closely correlated with an average of civil construction and plant, machinery and equipment costs—so choosing the most general measure of costs does not shift the assessment of growth in costs in any material way.

2.268 The distribution with the best fit for variations in the CGPI cost series was a normal distribution with a mean of 1 and a standard deviation of 0.026.

Underlying demand growth

2.269 We have used growth in Gross National Income (GNI) to depict variations in underlying demand growth. This is an obvious candidate because it reflects the combination of population growth and per capita income growth.

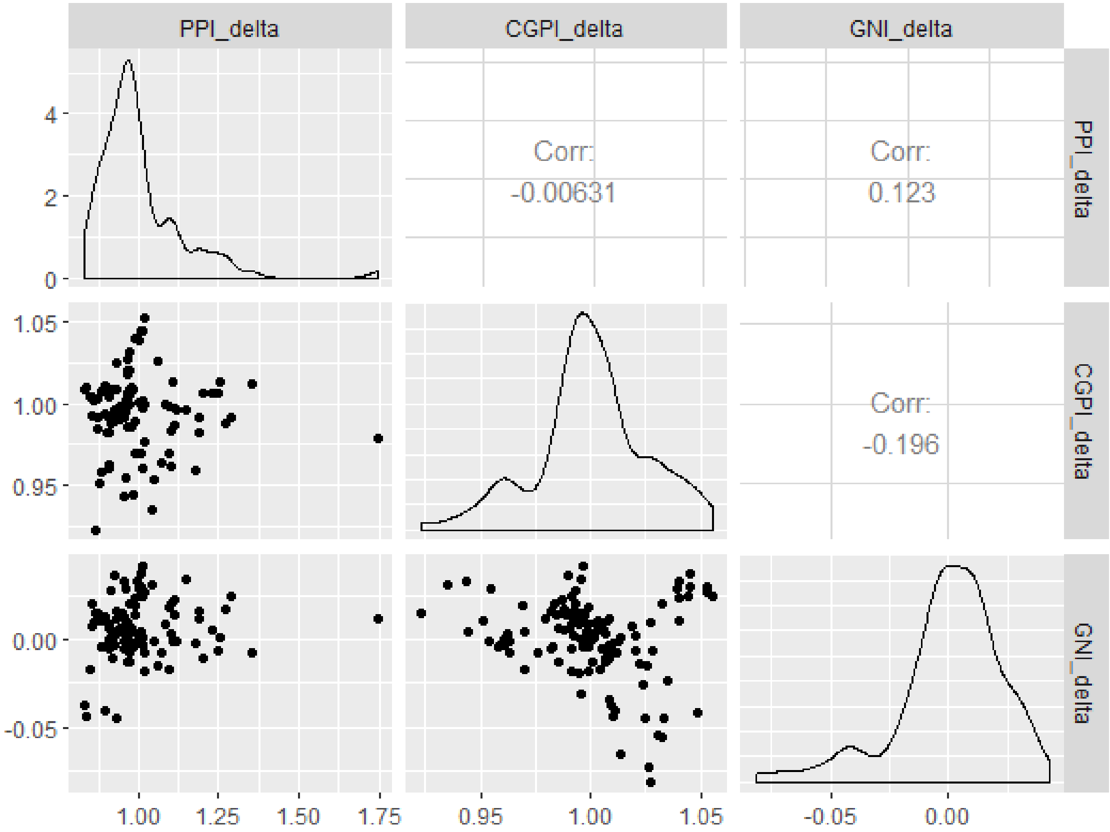
2.270 The distribution with the best fit for this data is a normal distribution, with a mean of 0 and a standard deviation of 0.011.

Distributions assumed to be independent

2.271 We have assumed the probability distributions chosen to depict variations in input assumptions are independent of one another.

2.272 This assumption is based on the observation that variations in the underlying data series (i.e., deviations from average growth rates) are not strongly correlated. This can be seen in Figure 7 below, which shows that the largest correlation is only -0.196—between deviations in GNI ('GNI_delta') and deviations in the CGPI.

Figure 7: Correlations between data used for input assumption probabilities



Source: Electricity Authority

Using probability distributions to weight model results

2.273 The grid use model's results have been weighted using the distributions described above, by assessing the **relative** likelihood of a combination of the input assumption values above as if these values have been drawn randomly.

2.274 For example, in our set of simulated results the input assumption value for short-run generation costs under the proposal's 'central' scenario with NZAS closing in 2024 has a 0.11 probability of occurring relative to the other assumptions in our list. Likewise, the input assumption values for long-run generation costs and demand growth under the proposal's 'central' scenario have 0.4 and 0.24 probabilities of occurring relative to the other values in our list. Thus, using this approach, the notional probability of the input assumption values for the proposal's 'central' scenario occurring is 0.01 (0.11 x 0.4 x 0.24). This notional probability provides a weight to be placed on the grid use model's result for the proposal's 'central' scenario (the central simulation (np_s)).

2.275 The actual weight applied to the result of a simulation of the grid use model (w_s), when summarising the model's results, is the simulation's notional probability divided by the sum of the notional probabilities of all other simulations of the grid use model, i.e., $w_s = np_s / \sum_s np_s$. For the central scenario this weight is 0.136.

Outlier removal

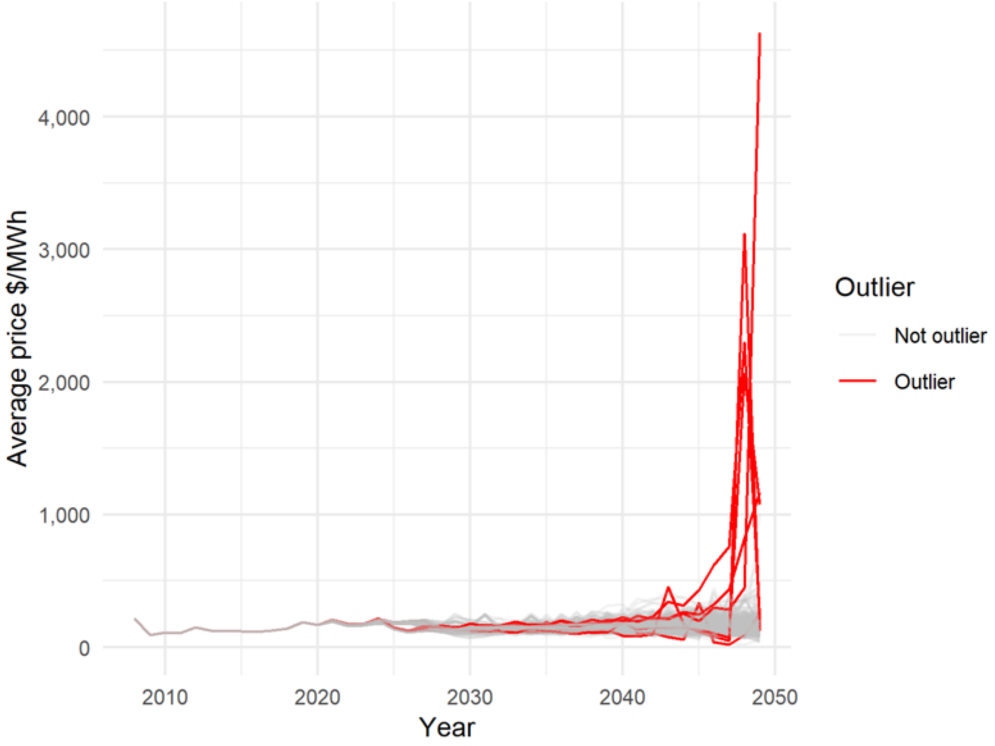
2.276 Seven of the sensitivity simulations (out of 400 simulations) have been excluded from results because they produce implausibly high prices (see Figure 8) and massive swings in demand in the final years of the simulation. These outlier events occur in high-cost sensitivity simulations and reflect the inability of the model, which is calibrated on contemporary market conditions, to adequately deal with extreme market conditions late in the simulation period, namely:

(a) extremely rapid rates of demand growth, with demand requiring substantial increases in generation investment equivalent to e.g. 500 MW of wind capacity built per year in the late 2040s

(b) very large differences between peak and off-peak prices with high penetration of low cost renewables but very high costs of serving peak demand, by historical standards.

2.277 While it would be ideal not to have to discard any simulation results, these results are instructive and point to the fact that the model has limitations, which is precisely the sort of finding that sensitivity testing is used to uncover. Furthermore, these limitations reflect known challenges with meeting high rates of demand growth while decarbonising electricity supply.

Figure 8: Outliers removed



Source: Electricity Authority

3 Benefits from more efficient investment by generators and large consumers

We have used a top-down assessment

3.1 Our estimate of the potential net benefit from the proposal leading to more efficient investment by generators and (large) consumers is based on a top-down assessment.

3.2 We define more efficient load and generation investment as private consumption decisions, over time, that minimise social costs of transmission investment.

3.3 Our focus is on consumption decisions because, from the perspective of a top-down assessment of costs and benefits, growth in consumption is not readily distinguishable from investment decisions by consumers and generators. Furthermore, we measure the costs and benefits of load and generation investment through effects on electricity consumption/demand.

3.4 This top-down assessment looks at a different aspect of consumer and generator investment decisions than does the assessment of more efficient grid use. Here, we are assessing the extent of any net benefit from a generator or consumer in a region being incentivised under the proposal to not make an investment/consumption decision that will necessitate transmission investment:

(a) in that region, or

(b) between that region and other regions.

The basic framework is an externality framework

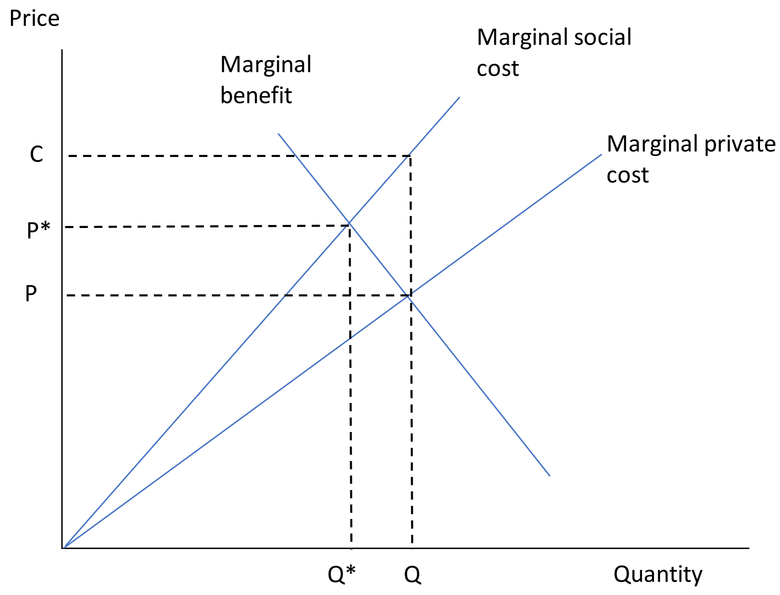
3.5 The basic framework is an externality framework: when marginal private costs of demand are lower than marginal social costs, electricity demand will exceed the level that is economically efficient for society. This is depicted in Figure 8, where the efficient price and quantity combination is P*,Q* but the market equilibrium is P,Q because consumers do not face marginal social costs of consumption. Marginal social costs incurred are C x Q.

3.6 Figure 8 depicts demand in a region that imports electricity under a regime where the costs of transmission are recovered from consumers in the importing region and consumers outside the importing region (the exporting region in a simple two region model).

3.7 Figure 9 provides an alternative representation of Figure 8, reflecting the dynamics of transmission investment. Levels of consumer demand are a function of nodal energy prices (P_e) and expectations of transmission charges under the status quo ($E[P_t]$) and with a benefit-based charge ($E[P^*_t]$). The diagram is a static snapshot of dynamic decisions. The dashed vertical lines reflect capacity limits on peak MW of demand due to fixed capacity (MW). Demand growth is lower when consumers in an importing region face a benefit-based charge. As a result, transmission capacity expansion (Q-Q*) is deferred. At the same time, growth in demand is expected to be higher in the exporting region because expectations of transmission charges will be lower.

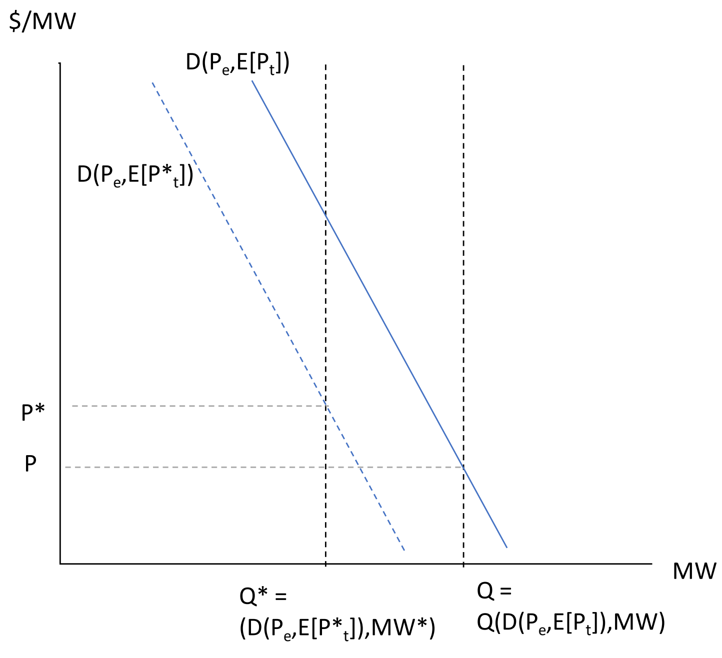
3.8 These fundamentals apply to both generation and demand decisions, however formulae for analysing demand differ from those for generation.

Figure 9: Excess demand with prices that do not reflect marginal social costs



Source: Electricity Authority

Figure 10: Efficient investment deferral, in an importing region



Source: Electricity Authority

Assessing transmission investment efficiency benefits arising from more efficient investment and consumption decisions by consumers

3.9 Our assessment framework for analysing benefits of more efficient demand investment (and consumption) decisions consists of determining:

(a) the extent (incidence and magnitude) to which cost-reflective transmission prices reduce demand growth in areas that are likely to require transmission investment

(b) the extent to which transmission investment follows demand growth, as opposed to enabling generation growth

(c) incremental costs of transmission investment.

3.10 To implement this framework, we further assume that long-run (efficient) transmission investment is, in real and current value terms, a constant function of peak demand growth. This implies that, over a multi-decade time period (from time 0 to time T), the current value of total transmission costs (TC) is simply a reflection of the change in aggregate peak demand (Q) and long-run unit/incremental costs (c) of transmission investment:

$$TC = (Q_T - Q_0).c \qquad \text{Equation 23}$$

3.11 This view of transmission costs is consistent with efficient, cost minimising, transmission investment decisions assuming constant productivity.

3.12 In addition, we make an assumption about the share of incremental transmission investment costs that are due to demand growth rather than to growth in generation independent of demand. Here, for expositional purposes, we refer to this as the share of transmission investment undertaken for reasons of reliability (s_r).

3.13 The current value of the benefit (B_c) of transmission investment deferral can then be measured as the proportional reduction in aggregate peak demand multiplied by expected aggregate peak demand and the expected incremental cost of reliability transmission investments:

$$B_c = -\frac{\Delta Q_T}{Q_T}.Q_T.c.s_r \qquad \text{Equation 24}$$

3.14 The welfare consequences of efficient transmission investment deferral will depend on the current status of transmission capacity. That is, whether investment deferral is likely to occur soon, or in the distant future.

3.15 Timing of transmission investment deferral can be measured, as a first approximation, by:

(a) forecast transmission E&D expenditure (c_t), which can be expected to be lower when transmission capacity is less constrained and higher when transmission capacity is more constrained, and

(b) forecast trend growth in peak demand.

3.16 When combined with discounting to account for social rate of time preference (δ) the formula for the present-valued benefits of transmission investment deferral is then:

$$B = \frac{\sum_t -\frac{\Delta Q_T}{Q_T} Q_t.c_t.s_r.\delta^t}{T} \qquad \text{Equation 25}$$

3.17 The percentage reduction in demand that is expected to occur with benefit-based charges can be calibrated using examples (a case study) and/or assumed long-run price elasticities of demand—elasticities that reflect demand investment decisions as well as short-run demand consumption decisions.[38]

3.18 If long-run elasticities were to be used, case studies would still be needed to determine potential changes in expected transmission charges. Case studies could be drawn from project-specific transmission investment analyses used in the modelling of more efficient grid use. For example, transmission prices and demand associated with the WUNI project could be compared to transmission prices and demand when benefit-based charges exist but when unapproved major capex, including the WUNI project, are not included in the model.[39]

3.19 If a long-run elasticity (η) is used and prices are calculated directly, by scenario, assumptions would need to be made about the typical amounts of demand affected by benefit-based charges. This is for the purpose of determining expected transmission price changes associated with benefit-based charges.

3.20 For example:

$$B = \frac{\left(-\sum_t \eta \frac{\Delta P}{P} Q_t . c_t . s_r . \delta^t\right)}{\mathrm{T}} \qquad \text{Equation 26}$$

$$\frac{\Delta P}{P} = \left(\frac{\frac{I(1+w+\rho+o)}{Y} \cdot \frac{1}{Q_A}}{\frac{I(1+w+\rho+o)}{Y} \cdot \frac{1}{Q_t}} - 1\right) . s_T = \left(\frac{Q_t}{Q_A} - 1\right) . s_T \qquad \text{Equation 27}$$

3.21 In this, a typical transmission investment (I in Equation 30) creates a benefit-based charge proportional to the rate of return on (w), and the rate of return of (i.e., depreciation of) (ρ), the investment, plus an operating expenditure (opex) allowance (o assumed here to be proportionate to the investment), in equal increments over the number of years (Y) that the capital costs are being recovered.

3.22 The annual cost is spread over the estimated typical demand of beneficiaries (Q_A), as opposed to being spread over total demand (Q_t). The reference price (denominator) for measuring the percentage change in demand is assumed to have the same energy (nodal) prices in both cases, so that we are isolating the effect on demand of the move to a benefit-based charge for recovering transmission investment costs. However, the demand elasticity is assumed here to be an elasticity with respect to wholesale electricity prices, inclusive of transmission interconnection charges. So, the price change needs to be adjusted to reflect the share of wholesale electricity prices that relates to recovery of the costs of transmission investment (s_T).

3.23 Note that the effect of the benefit-based charge on demand is evaluated at its maximum value in terms of deferral, occurring immediately before the transmission investment occurs, when expected benefit-based charges are largest.

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38 Consideration should also be given to adjusting long-run elasticities using actual transmission cost data, to account for the possibility that demand response based on expectations about transmission prices may differ from demand response based on actual/observed transmission prices. This difference in demand response would be the result of uncertainty associated with future transmission prices compared with actual/observed transmission prices.

39 Comparing effects under two scenarios that both exclude peak (RCPD) charges is necessary for separating allocatively efficient increases in demand, under the proposal, from effects on the efficiency of transmission investment over time.

3.24 To calculate the estimated transmission investment benefits due to more efficient demand investment (and consumption) decisions by consumers, we have used:

(a) long-run price elasticities of demand, and

(b) assumptions about the scope and incidence of benefit-based charges over the period of the CBA (i.e., 2021 – 2049), rather than modelled results.

3.25 This approach is more transparent than calculating estimated transmission investment efficiency benefits, using changes in demand taken from the model of demand used in estimating the net benefit of more efficient grid use. This sort of transparency is important for top-down analyses, which rely heavily on assumptions, because it enables the effects of assumptions to be interrogated easily.

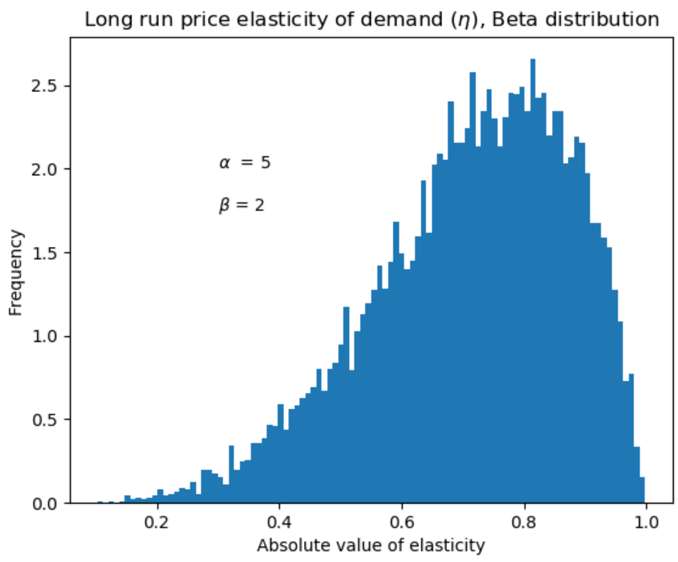
Parameters used

3.26 Table 21 contains the parameter values we used in our top-down assessment of transmission investment efficiency benefits due to more efficient investment and consumption decisions by (large) consumers.

3.27 We have applied a Monte Carlo analysis to some parameter values, to generate a distribution for the values. Figure 10 gives an example of the distribution generated for the long-run elasticity of demand parameter value.

3.28 The distributions chosen for parameter values reflect our knowledge of the parameter values. Where we have strong prior knowledge of a parameter value, uncertainty is expressed with a normal distribution. Where we have weaker prior knowledge about the correct central value for a parameter, we use the parameters of a beta distribution to specify reasonably large variances. We also use the beta distribution to specify skewed distributions. Where we have very weak prior knowledge about the central value of a parameter, we use a uniform distribution. Where reasonable, we have erred on the side of caution, by selecting parameter values that understate benefits and overstate costs.

Figure 11: Long-run price elasticity of demand



Source: Electricity Authority

Table 21: Parameters for transmission investment efficiency benefits due to more efficient investment and consumption decisions by consumers

Parameter	Value	Source / Comment
Long-run unit/incremental costs of transmission investment	Average of \$2.5m (real, \$2018)	Based on forecast average expenditure of \$83m (real, \$2018), and average demand growth (incremental MW) of 0.9% p.a. The use of projected expenditure as a cost basis helps to take account of variable timing in transmission investment.
Average transmission revenue per MWh	\$17	Revenue per MWh is calculated from projected revenue used in the grid use model and projected MWh under the central scenario in the grid use model with NZAS closing in 2024.
Share of transmission investment undertaken for reasons of reliability (being the share of incremental transmission investment costs that are due to demand growth rather than to growth in generation independent of demand)	44% Monte Carlo analysis: Beta (alpha=2, beta=2)	Percentage from modelling of efficient use of the grid.
Long-run price elasticities of demand, and transmission costs (variable i.e., E&D) as shares of wholesale electricity prices including interconnection charges	-0.74 elasticity Monte Carlo analysis: Beta (alpha=5, beta=2) 1.61% transmission costs share of prices Monte Carlo analysis: Normal (mu=0.0161, sigma=0.0005)	Elasticity from aggregate demand elasticity for consumers connected to distribution networks. Transmission share of costs based on: a. Forecast E&D capex b. Grid use model forecast demand and average energy prices c. Average transmission revenue per MWh
Forecast trend growth in peak demand	0.9% p.a. compound annual growth rate)	Growth rates from ‘Environmental’ scenario in Transpower’s Net Zero Grid Pathways 1 Major Capex Project (Staged) investigation (2021), Table B-3. Base year 2021 value updated for observed peak demand in August 2021.
Discount rate	6%	Assumption

Parameter	Value	Source / Comment
Depreciation on transmission investments	5%	Assumption
Quantity of demand over which the benefit-based charge for a demand-driven transmission investment is expected to be recovered (on average)	2,464 MW Monte Carlo analysis, modelled as share of peak demand, with the share distributed: Beta (alpha=2, beta=4)	A proxy for the average demand of the main expected beneficiaries of E&D base capex over the analysis period. Value unchanged from default value used in guidelines CBA based on an average over the following two arithmetic averages: a) The arithmetic average of the 2033 peak grid demand in regions expected to be the predominant beneficiaries of demand-driven E&D capex[40] by Transpower. b) The arithmetic average demand of the main expected beneficiaries of E&D base capex over RCP 2 and RCP 3.

Source: Electricity Authority

Assessing transmission investment efficiency benefits arising from more efficient investment by generators

3.29 Calculation of benefits from more efficient generation investment can be calculated using a similar formula to the one used for demand, but with:

(a) demand replaced by generation investment (MW)

(b) specific identification of areas where increases in generation are likely to create a need for investment in injection and export transmission capacity (export of generation, from a generator's perspective, as opposed to export of energy to load from the grid)—denoted with a subscript x (MW_x)

(c) reliability shares of spending replaced by, for example, economic shares of investment spending (s_e).

3.30 The formula is:

$$B = \frac{\sum_t -\frac{\Delta MW_{X,T}}{MW_{X,T}} MW_{X,t}.c_t.s_e.\delta^t}{T} \qquad \text{Equation 28}$$

3.31 As for the demand analysis, this equation could be parameterised, in terms of generation investment location decisions, using project-specific transmission investment analyses used in the modelling of more efficient grid use. Alternatively, this analysis could be undertaken using estimates of long-run marginal generation investment costs inclusive of transmission charges—so analysed independently of TPM effects on demand growth and hence demand for generation investment.

3.32 We have used estimates of long-run marginal generation investment costs, because this will be the most transparent method. This is consistent with our approach to assessing

40 I.e., major capex and E&D base capex.

transmission investment efficiency benefits arising from more efficient investment and consumption decisions by consumers.

Parameters used

3.33 Table 22 contains the parameter values we used in our top-down assessment of transmission investment efficiency benefits due to more efficient investment decisions by generators. We have applied a Monte Carlo analysis to some parameter values.

Table 22: Parameters for transmission investment efficiency benefits due to more efficient investment decisions by generators

Parameter	Value	Source / Comment
Forecast generation investment in areas likely to be export constrained without a benefit-based charge and without the distortion of SIMI charges or coincident peak demand charges	Sourced from central scenario of grid use model. Monte Carlo analysis: Normal (mu=3350, sigma=500)	Note this is a conservative approach. There may be intra-regional transmission efficiency benefits, which are not captured here.
Expected percentage change in generation investment in areas likely to be export constrained, with a benefit-based charge	-0.8% Monte Carlo analysis: Uniform (-0.02, 0)	From modelling of efficient use of the grid. The average difference in generation investment in export constrained regions under the central scenario in the modelling of the proposal's impact on efficient use of the grid is 0.8% lower than under the baseline. A uniform distribution over values between 0 and -2% is adopted, reflecting that we do not have strong priors as to the 'right' value.

Source: Electricity Authority

Benefits from greater scrutiny of proposed grid investments

3.34 An anticipated benefit of the proposal is a reduction in transmission investment costs, from beneficiaries of transmission investments having a greater incentive:

(a) to more closely scrutinise proposed transmission investments and provide information that enables lower cost (or deferred) transmission investments or transmission investment alternatives, or

(b) to not propose inefficient transmission investments.

3.35 We have modelled (a) as a productivity gain in the long-run cost of transmission investment (the c_t term discussed above). In relation to (b), we have modelled the undergrounding of transmission lines in Auckland, as a case study.

Parameters used

3.36 Table 23 contains the parameter values we have used in our top-down assessment of transmission investment efficiency benefits due to greater scrutiny of proposed grid investments by beneficiaries. The productivity factor improvement values are a little lower than in the 2019 CBA, reflecting our desire to ensure the CBA is conservative in its estimates of the proposal's benefits.

Table 23: Parameters for transmission investment efficiency benefits due to greater scrutiny of proposed grid investments by beneficiaries

Parameter	Value	Source / Comment
Greater stakeholder scrutiny and input into transmission investments	3% productivity factor improvement over Transpower's major capex reviewed by the Commerce Commission Sensitivities: 1% and 5%.	The Authority considers 3% to be reasonable. In support of this view are: • the 3% reduction in Transpower's proposed base capex for RCP 3 following the Commerce Commission's review of Transpower's RCP 3 proposal • the 4.4% reduction in Transpower's E&D base capex for RCP 2 that came from the Commerce Commission's scrutiny of the projects in Transpower's submission on the draft RCP 2 determination • the Commerce Commission's 1.25%, 2.5% and 5% downward adjustments on annual Transpower expenditure not regulated by the Electricity Commission in the 5–10 years preceding RCP 2.[41] We expect that greater stakeholder engagement and information provision in major capex investment decisions would deliver a similar efficiency benefit, over and above any efficiency benefit from the Commerce Commission's review of a major capex proposal.
Greater stakeholder scrutiny and input into transmission investments	3% productivity factor improvement over Transpower's E&D base capex not reviewed by the Commerce Commission when approving Transpower's RCP proposal.	The Authority considers 3% to be reasonable. In support of this view are: • the 3% reduction in Transpower's proposed base capex for RCP 3 following the Commerce Commission's review of Transpower's RCP 3 proposal • the 4.4% reduction in Transpower's E&D base capex for RCP 2 that came from the Commerce Commission's scrutiny of the projects in Transpower's submission on the draft RCP 2 determination • the Commerce Commission's 1.25%, 2.5% and 5% downward adjustments on annual Transpower expenditure not regulated by the Electricity Commission in the 5–10 years preceding RCP 2.

41 The Electricity Commission regulated Transpower's major E&D capex, while the Commerce Commission regulated Transpower's R&R expenditure, E&D expenditure, and operational IT-related expenditure.

Parameter	Value	Source / Comment
	Assume 30% of E&D base capex is not reviewed by the Commerce Commission. Sensitivities: 1% and 5%.	Based on RCP 2 E&D base capex.
Greater stakeholder scrutiny and input into transmission investments	1.5% productivity factor improvement over all of Transpower's E&D base capex that was reviewed by the Commerce Commission when approving Transpower's RCP proposal. Assume 70% of E&D base capex is reviewed by the Commerce Commission. Sensitivities: 0.5% and 2.5%.	Mid-point between lower bound productivity factor improvement (0%) and estimated productivity factor improvement from greater stakeholder scrutiny of E&D base capex not reviewed by the Commerce Commission. Based on RCP 2 E&D base capex.
Greater stakeholder scrutiny and input into transmission investments	1.5% productivity factor improvement over 15% of Transpower's R&R base capex. Sensitivities: 0.5% and 2.5%.	We consider it reasonable to expect stakeholders would be more likely to promote efficiency gains for R&R base capex that could be covered by deeper connection charges (e.g., interconnection transformer capacity, AC substation busbar refurbishments and security upgrades). We estimate approximately 15% of R&R base capex falls in this category. This estimate uses as a proxy for such assets 50% of base capex on AC substations, ACS buildings & grounds, and Secondary assets. Refer to base capex over RCP 1–5 per Transpower's RCP 3 proposal. Consistent with E&D base capex, a 1.5% productivity factor improvement is used over R&R base capex reviewed by the Commerce Commission. We assume no R&R base capex has a 3% productivity factor improvement applied. During a regulatory control period, it is very rare for a new transmission project to be added to the list of projects for which R&R base capex has been approved by the Commerce Commission. This is because R&R base capex relates to the upkeep of existing transmission assets based on known condition assessment and asset life cycle strategies. This contrasts with E&D base capex, which is more uncertain when

Parameter	Value	Source / Comment
		approved by the Commerce Commission, because it is typically demand-driven, and demand forecasts are inherently uncertain over the medium to longer term.
Greater stakeholder scrutiny and input into transmission investments	0.5% productivity factor improvement over R&R base capex that is not: • recovered via connection charges • the 15% of R&R base capex that could be covered by deeper connection charges. Sensitivities: 0% and 1.5%.	One third of estimated productivity factor improvement from greater stakeholder scrutiny of R&R base capex reviewed by the Commerce Commission. We have applied a 0.5% productivity factor improvement because stakeholders are unlikely to be able to promote efficiency gains to the same extent for R&R base capex that is not recovered via connection charges or which could be covered by deeper connection charges. Examples include tower painting (which accounted for $238m of R&R base capex in the RCP 3 proposal), transmission tower foundation refurbishments, and improving the seismic performance of HVDC buildings. We estimate approximately 15% of R&R base capex is recovered via connection charges. This estimate relies on connection charges recovering 50% of base capex on AC substations, ACS buildings & grounds, and Secondary assets. Refer to base capex over RCP 1–5 per Transpower's RCP 3 proposal.
Less likelihood of inefficient investments being proposed Case study: Undergrounding of all urban transmission lines in Auckland	Change in probability of undergrounding all urban transmission lines in Auckland proceeding in absence of a benefit-based charge: 25% Sensitivities: 0% change in probability 50% change in probability	NB: We are only concerned about the probability of economically inefficient investment in the undergrounding of all of Auckland's urban transmission lines occurring in the absence of the proposal. We assume that if the undergrounding of all of Auckland's urban transmission lines occurs with the proposal in effect, then this undergrounding is economically efficient. So, if we assume there is a 5% probability of undergrounding occurring with the proposal in effect, and a 30% probability in the absence of the proposal, then the probability of economically inefficient investment in undergrounding is 25%.
Less likelihood of inefficient investments being proposed Case study: Undergrounding of all urban	Should inefficient undergrounding proceed, assume this occurs over the period 2035-2045.	Refer to "Powering Auckland's Future"—Transpower's strategy to support Auckland's growth and blueprint for further work. Transpower's blueprint for further work in Auckland includes undergrounding new 220 kV lines between 2030 and 2050

Parameter	Value	Source / Comment
transmission lines in Auckland		(Brownhill Road to Otahuhu (as part of the NIGU) and Pakuranga to Albany).

Source: Electricity Authority

Benefits from increased policy certainty for investors

3.37 Compared with the baseline, we expect the proposal would be less likely to be subject to successful challenge and change or reversal, whether on grounds of inefficiency or unreasonableness. We consider that this would reduce the cost of investing (i.e., reduce the return needed to trigger an investment) in both demand-side and supply-side assets.

3.38 This is based on evidence that uncertainty increases the value of delaying an investment (so-called real options), and increases the level of private benefits required to trigger an investment.[42]

3.39 Analysing these effects requires:

(a) specifying the impact on uncertainty (size of shock) of a TPM based on the proposed guidelines

(b) specifying marginal effects of uncertainty on investment costs.

3.40 One simplified (reduced form) framework for assessing these effects is to analyse long-run supply and demand in terms of a static equilibrium (possibly the most simplified approach). For example, assume that long-run electricity demand is a linear function of prices (P), incomes (M) and a measure of policy uncertainty (U),[43] and supply is a linear function of prices and policy uncertainty.

$$Q_d = \alpha_d + \beta_d P + \delta_d U_d + \gamma M \qquad \text{Equation 29}$$

$$Q_s = \alpha_s + \beta_s P + \delta_s U_s \qquad \text{Equation 30}$$

3.41 Given an estimate of the incremental effects of policy uncertainty on investment, measured in terms of, for example, peak supply and peak demand, we can estimate effects on quantities supplied. Assuming prices do not change, the benefits of increased policy certainty would be equal to the change in total surplus from the increase in quantities:

$$\Delta TS = \frac{P\delta_s \Delta U_s + (\bar{P} - P)\delta_d \Delta U_d}{2} \qquad \text{Equation 31}$$

Where $\bar{P}$ is the price at which demand is equal to 0.

3.42 Prices may change too, depending on the responsiveness of demand and supply to changes in policy uncertainty.

3.43 With demand equal to supply, the long run equilibrium price level is:

$$P = \frac{\alpha_d - \alpha_s + \delta_s U_s - \delta_d U_d + \gamma M}{(\beta_s - \beta_d)} \qquad \text{Equation 32}$$

42 A considerable amount of research has been carried out into real options effects over the past quarter century. This research has mostly been theoretical, but it has also been validated in empirical case studies of investment (e.g., Kellogg, R. (2014). The Effect of Uncertainty on Investment: Evidence from Texas Oil Drilling. *The American Economic Review*, 104(6), 1698–1734.)

43 Note that no distinction is made between risk (knowable) and uncertainty (unknowable). Consideration of this difference is, however, relevant when it comes to parameter estimates.

3.44 If we assume that sources of policy uncertainty are identical between demand and supply, then the effect of a change in policy uncertainty on prices is zero:

$$\frac{\partial P}{\partial U} = \frac{\delta_s}{\beta} + \frac{\delta_d}{\beta} = \frac{\delta_s - \delta_d}{\beta} = 0 \qquad \text{Equation 33}$$

3.45 The parameters that need calibrating are:

(a) the long-run response of supply to prices (β_s)

(b) the long-run response of demand to prices (β_d)

(c) the responsiveness of demand and supply to changes in policy uncertainty (δ_d and δ_s)

(d) a measure of the effects of a change in policy uncertainty on investment

(e) a measure of the expected unit change in policy uncertainty.

3.46 A total surplus measure of benefits from increased policy certainty is:

$$\Delta TS = \frac{1}{2}((P'Q' - PQ) + ((\bar{P} - P')Q' - (\bar{P} - P)Q)) \qquad \text{Equation 34}$$

Where new prices and quantities, with increased policy certainty, are P' and Q' and $\bar{P}$ is the notional price at which demand is equal to zero, calculated based on:

$$\bar{P} = \frac{Q(P=0)}{-\beta_d} \qquad \text{Equation 35}$$

$$Q(P = 0) = Q^* - \beta_d . P^* \qquad \text{Equation 36}$$

3.47 We have drawn on several international sources/experiences when considering possible effects of policy uncertainty on investment.

3.48 Research from the United States 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.[44] 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.[45]

(c) Gulen and Ion (2016) use an index of policy uncertainty throughout the economy to estimate effects of uncertainty on economy-wide 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).[46] They also find that the dampening effect

44 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.

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

46 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

of uncertainty on investment is highest in industries where investments are typically irreversible.

3.49 These findings are supported locally by researchers at the Reserve Bank of New Zealand who found a negative relationship between uncertainty and macroeconomic measures of economic activity including investment.[47]

3.50 From the United Kingdom, Buckland and Fraser (2001) found that market risk values ('betas') for electricity distributors showed significant variation in response to policy uncertainty.[48] A policy announcement that induced uncertainty was shown to increase systematic asset risks (beta) by 40% to 60% for five months after the announcement.

3.51 Other research into the effects of policy uncertainty tends to be more theoretical,[49] or related to developments in developing countries.[50] Historically, developing countries have faced fundamentally different (greater) issues in respect to policy uncertainty, due to weaker institutions.

3.52 Given that empirical research focusses on investment effects of uncertainty, estimates of the responsiveness of demand and supply to changes in policy uncertainty (δ_d and δ_s) need to translate investment effects into effects on demand and supply. To calibrate the effect of a change in policy uncertainty on investment and then on output, we make use of typical (average) relationships between the capital stock and output (dY/dK) and typical rates of investment as a share of the capital stock (I/K).

$$dI = dU \frac{dI}{dU} Y \frac{dY}{dK} \frac{I}{K} \qquad \text{Equation 37}$$

3.53 We then consider the average effects on output of a present-valued change in investment (dI_{PV}):

$$\delta = \frac{dQ}{dU} = \left(dI_{PV} \frac{dY}{dI}\right) . \frac{1}{P} \qquad \text{Equation 38}$$

3.54 If we assume linear demands, values for supply and demand response parameters can be calibrated using demand elasticities (η_d) or supply elasticities and assumptions about average market prices (P^*) and quantities (Q^*)—for example:

$$\beta_d = \frac{\eta_d}{\frac{P^*}{Q^*}} \qquad \text{Equation 39}$$

Parameters used

3.55 Table 24 contains the parameter values we used in our top-down assessment of transmission investment efficiency benefits due to increased certainty for investors. We have applied a Monte Carlo analysis to some parameter values.

3.56 Parameter values are unchanged from the Guidelines CBA. While we have updated our baseline demand growth assumptions these have not been carried over into this analysis. The reason for this is that the proposed TPM contains elements of uncertainty

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

48 Buckland, R., & Fraser, P. (2001). Political and Regulatory Risk: Beta Sensitivity in U.K. Electricity Distribution. *Journal of Regulatory Economics*, 19(1), 21.

49 E.g., Pástor, Ľ., & Veronesi, P. (2013). Political uncertainty and risk premia. Journal of Financial Economics, 110(3), 520–545. https://doi.org/10.1016/j.jfineco.2013.08.007. Although the authors do test their theoretical model this testing is rather limited.

50 Rodrik, D. (1991). Policy uncertainty and private investment in developing countries. *Journal of Development Economics*, 36(2), 229–242. https://doi.org/10.1016/0304-3878(91)90034-S

around future calculations of benefit-based charges, from a review of generators shares of benefit-based charges under the simple method. Thus we use a lower demand growth rate so as to moderate the estimated benefits from increased certainty.

3.57 In addition, average forecast demand levels used in this analysis are not very different from those used in the Guidelines CBA because although demand growth rates are higher the baseline scenarios include the NZAS closure in 2024.

Table 24: Parameters for transmission investment efficiency benefits due to reduced uncertainty for investors

Parameter	Value	Source / Comment
Forecast trend growth in electricity prices with current level of policy uncertainty	0.9% p.a. Monte Carlo analysis conducted by varying price growth rates: Normal (mu=0.00906, sigma=0.005)	Select the value that minimises benefits from the proposal (to err on the side of not overstating proposal benefits). Mindful that higher demand growth, with increased generation investment, will increase estimated benefits from reduced uncertainty. However, the proposed TPM may introduce new sources of uncertainty, so we have erred on the side of a low growth rate (the one used in the guidelines CBA), as a central scenario.
Long-run response of demand to prices	-0.74 elasticity Monte Carlo analysis: Beta (alpha=5, beta=2)	As above, long-run price elasticity of demand estimated during preparation of CBA demand model. This elasticity is appropriate as long as the estimated price changes being evaluated are not large (and are within the range, say one standard deviation, of the sorts of price changes observed in the data used to estimate the elasticities—otherwise they could imply infeasibly large demand changes).
Long-run response of supply to prices	1 Monte Carlo analysis: Normal (mu=1, sigma=0.25)	Assume that supply is perfectly elastic over the long run.
Factor representing responsiveness of investment to change in policy uncertainty	A doubling of policy uncertainty reduces investment by 8.7% (elasticity of investment response to change in uncertainty = 0.087/2) Monte Carlo analysis: Normal (mu=0.0435, sigma=0.01)	Refer to Gulen, H., & Ion, M. (2016). Policy Uncertainty and Corporate Investment. The Review of Financial Studies, 29(3), 523–564.

Parameter	Value	Source / Comment
Factor representing expected change in uncertainty	Uncertainty assumed to be proportional to the frequency of political events. Assume 10 yearly political uncertainty events become 11 yearly political uncertainty events. Monte Carlo analysis for percentage change in frequency of events: Normal (mu=0.09, sigma=0.03)	For motivation refer to Buckland, R., & Fraser, P. (2001). Political and Regulatory Risk: Beta Sensitivity in U.K. Electricity Distribution*. Journal of Regulatory Economics, 19(1), 21.
Average forecast demand (MWh)	47,015,448 Monte Carlo analysis conducted by varying demand growth rates: Normal (mu=0.009, sigma=0.005)	Assumption carried over from the Guidelines CBA. Value similar to average demand in grid use model baseline, averaged over scenarios with and without Tiwai closing in 2024 (value of 47,142,457),
Effect of investment on demand and supply	0.05475 Monte Carlo analysis: Normal (mu=0.05, sigma=0.01)	Assess the ultimate effect of an increase in investment on an increase in output. Value-based ratio of investment to capital stock (excluding property) multiplied by the ratio of output to the capital stock—national accounts averages 1987-2017.

Source: Electricity Authority

4 Costs of load or generation not locating in regions with recent investment in transmission capacity

Cost of load not locating in regions with recent investment in transmission capacity

4.1 Once a transmission investment is sunk, a benefit-based charge may continue to deter demand growth, as new demand investment gravitates to areas with lower benefit-based charges. This could lead to displacement of demand investment from the region where the benefit-based charge applies.[51]

4.2 Notably, the displaced demand need not be a consumer moving their demand from a region with a benefit-based charge. Rather, it could be a consumer increasing their demand in a region without a benefit-based charge, while a consumer in a region with a benefit-based charge delays increasing their demand.

4.3 Displacement of demand investment would be inefficient if the decision to invest in load in a location with lower benefit-based charges brings forward transmission investment in that location at a speed and scale that exceeds any incremental effects on the need for new transmission investment in the area with higher current benefit-based charges.[52]

4.4 Costs from displaced demand investment can be calculated using the same formula as for calculating benefits from more efficient demand investment (Equation 29), with adjustments to reflect the fact that:

(a) electricity prices are only one part of a decision to choose a location for new investment, with other factors including:

(i) local amenities

(ii) local prices for, and availability of, inputs (e.g., land, raw materials, and human capital)

(iii) local demand

(iv) transport costs

(b) other things being equal, demand is likely to gravitate to areas that are least constrained, in terms of transmission capacity, because energy prices will be lowest in these locations.

4.5 As such, costs of displaced demand would need to be adjusted by parameters reflecting:

(a) the amount of forestalled demand that is displaced to another region (D, where $0 < D < 1$), and

(b) the extent to which demand displaced to another region by a benefit-based charge reduces the time lag (L) (i.e., brings forward) before investment is needed to relieve transmission congestion in the other region (L, where $0 < L < 1$).

4.6 If the costs are also calculated using a long-run demand elasticity (η), the cost would be:

$$C = \frac{\sum_t \eta \frac{\Delta P}{P} Q_t . D . L . c_t . s_r . \delta^t}{T} \qquad \text{Equation 40}$$

[51] Any net reduction in demand is an unavoidable cost of revenue recovery and something taken into account in our estimates of changes in allocative efficiency.

[52] In addition, it could also be inefficient even if it does not bring forward transmission investment—simply by driving the consumer into a more costly pattern of demand-side investment.

4.7 The displacement parameter could be reasoned using a model (i.e., equation) of its own, based on conventional models of firm location decisions, or drawing on empirical research into locational decisions of firms.[53] Historically, large electricity-intensive loads have tended to locate near raw materials in New Zealand, though this may reflect a mixture of economic fundamentals and past pricing methodologies.

4.8 We have not adopted this approach because we believe identification problems would be considerable, relative to our preferred and simpler approach set out in Table 25. A considerable majority of large electricity intensive manufacturing plants (major direct-connect consumers) were established decades ago when energy and network access pricing differed substantially from the sorts of methodologies and markets used today.

Parameters used

4.9 Table 25 contains the parameter values we used in our top-down assessment of costs due to load not locating in regions with recent investment in transmission capacity. We have applied a Monte Carlo analysis to some parameter values.

Table 25: Parameters for assessment of costs due to load not locating in regions with recent investment in transmission capacity

Parameter	Value	Source / Comment
Discount factor (where 0 < D < 1) representing expected amount of forestalled load locating in another region due to a benefit-based charge	0.5 (Monte Carlo analysis: Beta (alpha=2, beta=2) Sensitivities: a) Very low D value(s) (e.g., D=0, D=0.05, D=0.1) b) Higher D value(s) (e.g., D=0.75)	We consider it is reasonable to expect that, over the long run, a benefit-based charge would displace some forestalled demand. 0.5 chosen as a very conservative estimate, consistent with the CBA being conservative (the higher the "D" value, the more forestalled demand that is displaced to another region, thereby increasing the likelihood of inefficient transmission investment being required in the other region).
The change in the present value multiplier due to bringing forward transmission investment to relieve congestion caused by a change in demand	0.03 (Monte Carlo analysis: Beta (alpha=2, beta=60)	Central estimate based on investment brought forward, from 10 years hence to 9 years hence. Assume demand-driven transmission investment in other region not needed for at least 10 years, because displaced demand would not locate in a region where transmission investment was likely to occur in the short to medium term. Discount rate of 6% used in calculating the change in the present value multiplier.

Source: Electricity Authority

53 For a reasonably recent summary see: Arauzo-Carod, J.-M., Liviano-Solis, D., & Manjón-Antolín, M. (2010). Empirical Studies in Industrial Location: An Assessment of Their Methods and Results*. *Journal of Regional Science*, 50(3), 685–711. https://doi.org/10.1111/j.1467-9787.2009.00625.x

Cost of generation not locating in regions with recent investment in capacity

4.10 We have assessed the cost of generation not locating in regions with recent investment in transmission capacity as part of our assessment of the benefits of more efficient grid use. This cost reduces the net benefit associated with lower energy prices from generation investment.

Cost of grid investment brought forward

4.11 We have assessed the cost of grid investment brought forward as part of our assessment of the benefits of more efficient grid use.

5 Costs of developing, implementing and operating a new TPM

Cost estimates are an update on estimates for the 2020 guidelines CBA

5.1 Costs of developing, implementing and operating the proposed TPM have been estimated by taking the cost estimates in the 2020 Guidelines CBA and updating those costs for new information contained in Transpower's forecasts of implementation costs.

5.2 The Guidelines CBA cost estimates were based primarily on Transpower's assessment in 2016 of costs to develop, implement and operate a new TPM based on the proposed guidelines in the 2016 Issues paper. Those cost estimates erred on the side of overstating costs, choosing estimates from a scenario that presumed the TPM would be highly complex to develop and implement and operate.

5.3 The Guidelines CBA estimated $26m of development, implementation and ongoing operation/administration costs, broken down as follows:

(a) $7.83 million for TPM development and approval, comprising—

(i) $4.08 million of Transpower costs

(ii) $0.75 million of Authority costs

(iii) $1.5 million of stakeholder costs

(iv) $1.5 million of legal costs across the Authority, Transpower and various stakeholders

(b) $8.61 million for TPM implementation, comprising—

(i) $6.44 million of Transpower costs

(ii) $0.67 million of stakeholder costs

(iii) $1.5 million of legal costs across the Authority, Transpower and various stakeholders

(c) $9.26 million for TPM ongoing administration/operation, comprising—

(i) $8.88 million of Transpower costs

(ii) $0.37 million of stakeholder costs.

New information leads to an increase in costs to Transpower

5.4 Transpower is currently forecasting to spend $27.4 million (2020/21 dollars) developing and implementing the systems and processes to administer the new TPM, $11 million of which will be ICT capex.[54] The equivalent cost estimate in the Guidelines CBA was approximately $10.5 million.

5.5 Transpower's 2020-21 financial year (ending 30 June) budgeted expenditure on TPM development and implementation was $4.44 million.[55] Subtracting this $4.44 million from the $27.4 million above leaves approximately $23 million of forecast Transpower

54 Transpower New Zealand, 2021, 2021 Integrated Transmission Plan Narrative, pp. 9-10 and p. 33, and Transpower New Zealand, 2021, 2021 Asset Management Plan, p. 433. Available at https://www.transpower.co.nz/keeping-you-connected/industry/rcp3/rcp3-updates-and-disclosures.

55 Deloitte, November 2020, Transmission Pricing Methodology (TPM) Project Review 2020: Internal Audit Report, p. 10.

expenditure on TPM development and expenditure from 1 July 2021. This is approximately $12.5 million higher than the Guidelines CBA's estimate of Transpower's total TPM development and implementation costs.

5.6 Given this increase, $12 million (2018 dollars) has been added to the estimate in the Guidelines CBA of Transpower's total TPM development and implementation costs, to reflect this new information from Transpower. Adding $12 million rather than $12.5 million mentioned in the above paragraph reflects an allowance for:

(a) costs incurred by Transpower on TPM development and implementation from 1 July 2021 to 30 September 2021, prior to the start of the proposed TPM CBA assessment period

(b) the fact that Transpower's costs are in 2020-21 dollars rather than 2018 dollars.

5.7 Updating our previous estimates to incorporate Transpower's subsequent cost estimates to develop and implement the TPM is reasonable. It is consistent with the prior use, as an input to the Guidelines CBA, of Transpower's estimate of its costs to develop, implement and administer a TPM based on the proposed guidelines in the 2016 Issues paper.

5.8 We have no new information to update our estimates of the ongoing cost to administer the proposed TPM. In the absence of any new information from Transpower, the previous estimate of approximately $8.9m has been adopted. This assumes additional resourcing relative to the status quo of approximately 10.5 FTEs in the first year of the new TPM's operation, dropping to approximately 5 FTEs of additional resourcing thereafter.

5.9 Using the Guidelines CBA's number may be a little conservative (high) given the amount of ICT capex Transpower is proposing to spend implementing the TPM. We infer from the higher capex (relative to Transpower's 2016 estimate) that Transpower is intending to automate processes as much as practicable, thereby minimising the uplift in ongoing human resourcing requirements.

Cost to Authority unchanged

5.10 The Guidelines CBA estimated $750,000 of costs for the Authority's TPM development and approval process. That was based on 4 FTEs, at a cost per FTE of $250,000, working on TPM development and approval for 9 months. The $250,000 was a blended rate for Authority staff, contractors and consultants.

5.11 This cost estimate retains the same $750,000 cost estimate. Although there is less than 9 months' time available for work on TPM development and approval, it is prudent to retain the $750,000 cost estimate for use in this CBA. This allows for the Authority using more than 4 FTEs during the development and approval of the TPM.

5.12 As in the Guidelines CBA, we assume no ongoing administrative costs for the Authority from the proposed TPM, over and above costs that would ordinarily be incurred in the baseline (ie, under the current TPM).

Stakeholders' costs unchanged

5.13 The Guidelines CBA included an estimated $1.5 million in costs to stakeholders engaging in the TPM development and consultation process. The value was based on an estimate of the number of submissions made by stakeholders weighted by expected complexity of submissions.

5.14 Based on engagement to date on Transpower's TPM development,[56] we have retained the $1.5 million cost estimate for this CBA. Using the same input assumptions as the Guidelines CBA,[57] the estimated cost incurred by stakeholders engaging in the TPM development process to date is a little under $0.5 million. This leaves a cost estimate of a little over $1 million for stakeholder engagement during the Authority's consultation on the proposed TPM.

Legal challenge costs unchanged

5.15 Given the current legal challenge to the Authority's decision to publish the 2020 TPM guidelines, it would seem prudent to retain an allowance for legal fees during the development and implementation of the TPM. The Guidelines CBA's $3 million estimate has thus been retained for this CBA.

Costs estimated to range from $19m to $57m

5.16 Table 26 sets out the items that make up our estimates of development, implementation and operation costs. In total these are $38 million. To place a range around this value we add and subtract 50% of these costs, yielding a cost range of $19 million to $57 million. The 50% variation is the same percentage used in the 2020 CBA, which in turn was the same percentage Transpower and PWC adopted when estimating these costs in 2016.

Table 26: TPM development, implementation and operation costs

TPM development / approval

Cost category	Cost
Transpower TPM development cost	$5,080,000
Authority TPM approval cost	$750,000
Stakeholder participation cost	$1,500,000
Legal challenge cost	$1,500,000
Total	**$8,830,000**

TPM implementation costs

Cost category	Cost
Transpower TPM implementation cost	$17,440,000
Designated transmission customers' implementation cost	$670,000
Legal challenge cost	$1,500,000
Total	**$19,610,000**

56 Based on information on its website (https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm), it appears Transpower received the following on its consultations during the development of the TPM:

a) 97 submissions

b) 17 cross-submissions

c) 6 new external consultant reports, plus one external consultant report prepared in 2015.

57 Electricity Authority, CBA approach, methods and assumptions: TPM decision paper 2020 – Technical paper, Table 27, p. 94.

TPM ongoing/operational costs

Cost category	Cost
Transpower year 1 administration cost	$1,140,000
Transpower years 2-5 administration cost	$1,970,000
Transpower years 6-30 administration cost	$5,770,000
Stakeholder ongoing cost – transmission asset optimisation	$370,000
Total	**$9,250,000**

Source: Electricity Authority