Appendix F TPM supplementary consultation modelling results

This appendix summarises the results of supplementary consultation modelling of the impacts of the proposed TPM guidelines. Two modelling scenarios are presented below, each estimating the charges for the first year of implementation of the TPM proposal.

Scenario 1 includes:

- some anomalies addressed (as discussed below)
- transmission and distribution charges adjusted to reflect potential changes to the weighted average cost of capital (WACC) that may apply for Transpower and regulated distributors for Regulatory Control Period 3 (RCP3), that commences from April 2020
- the North Island grid upgrade (NIGU) investment remodelled (as discussed below)
- a capping mechanism intended to limit any transmission charge increase:
    - for a distributor, to no more than 3.5% of the distributor's end customers estimated total electricity bills in the 2019/20 pricing year (plus inflation)
    - for a direct consumer, to no more than 3.5% of the direct consumer's estimated total electricity bill in the 2019/20 pricing year (plus inflation)[1]

Scenario 2 includes the same effects as scenario 1 except that it does not include the WACC adjustment to Transpower and distributors that could apply for RCP3.

Neither scenario includes the loss and constraint excess (LCE) adjustment component of the TPM proposal (ie, as described in chapter 3). A case study or studies will be provided separately, during the consultation period for this paper, of the effect of the LCE adjustment.

The specific changes arising under each scenario are explained in more detail below.

It is important to note that the modelling assumes that the avoided cost of transmission (ACOT) subsidy to distributed generators will continue to be paid in full. This is a conservative assumption as it inflates the impact of the TPM proposal on electricity prices for households and other consumers. On 6 December 2016, the Authority announced a decision to amend the Code so that distributed generation that does not efficiently defer or reduce grid costs will no longer receive ACOT payments under the regulated terms.[2] ACOT payments are currently in the vicinity of $60 million per year and the Authority's initial estimate is that ACOT payments will reduce by $25 to $35 million per year. Reductions in ACOT payments to distributed generators flow through to consumers in the form of lower retail electricity prices. If current ACOT payments were reduced by half for scenario 1, this would cause even greater price reductions for households. For scenario 2, on average, the ACOT adjustment would roughly offset the indicative increases for households, meaning a (roughly) zero impact of the TPM proposal on households.

1 See chapter 3 for the exact specification of the cap.

2 The decision paper is available at: http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-part-6-dg-pricing-principles/development/authority-decision-on-the-review-of-dgpps-and-acot/.

Anomalies in earlier modelling

A review of the modelling for the May 2016 second issues paper found a number of anomalies that affected the 'gross AMD' measure for some parties. Addressing these anomalies has resulted in lower modelled residual charges than shown in the second issues paper for affected parties. Specifically, the anomalies include:

- adjustment of gross AMD[3] for:
  - Westpower, reflecting:
    - Oceania mine's exit from Reefton, and
    - aggregation of load[4] at Reefton
  - Buller, reflecting:
    - Holcim Cement's exit from Westport, and
    - aggregation of load at Orowaiti
  - Electricity Ashburton, reflecting
    - aggregation of load at Ashburton.
- modelling 25 MW of additional Ngawha generation by removing demand from Kaikohe
- the inclusion of Pacific Steel's charges into NZ Steel's charges, and the de-rating of load at Mangere (MNG)[5]
- improved modelling of demand response at NZ Steel's Glenbrook (GLN) site.

Reduction in WACC effect

The fall in interest rates since 2014 when the Commerce Commission (Commission) last reset the WACC and thus the revenue requirements for Transpower and price-regulated distributors means that it is possible that a lower WACC may be used by the Commission to reset the price paths that apply to Transpower and price-regulated distributors from April 2020.

In the May 2016 second issues paper, the Authority calculated indicative transmission charges and electricity bill impacts based on the revenue requirements and WACC determined by the Commerce Commission in 2014 (ie, ignoring the subsequent fall in interest rates). The Commerce Commission recalculates the WACC regularly, using recent market data. The most recent determination on WACC (September 2016) showed the WACC has declined to 5.32%.[6]

For scenario 1 of our modelling, we have applied the effect of a WACC of 5.32%. Reducing Transpower's WACC from 7.19% to 5.32% would result in an estimated $86m (or 9%) reduction in Transpower's maximum allowable revenue (MAR) for the 2020 transmission pricing year, all other factors being equal.[7] Applying the reduced WACC to distributors results in an average

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3 These reductions are required because the modelling uses 2014 market data, which does not include subsequent material load changes such as the exit of Holcim Cement from Westport.

4 When two points of connection (POCs) serve the same load from a single bus, this is combined to a single POC.

5 In the second issues paper, Pacific Steel's Mangere load was modelled as zero, reflecting media reports that that plant was to be closed, with a lesser quantum of load to be transferred to other sites. However, the Authority has been informed that this is not the case and there is still load at Mangere (this lesser load is now attributable to NZ Steel due to the change in ownership).

6 Commerce Commission, Cost of capital determination for customised price-quality path proposals made by electricity distribution businesses [2016] NZCC 20, 30 September 2016.

7 This calculation assumes that Transpower's regulatory asset base (RAB) in 2020 remains constant at the current level of $4,600 million. This is a simplifying assumption made for indicative purposes. For information on the current level of the Transpower RAB see www.transpower.co.nz/sites/default/files/uncontrolled_docs/IPP%20Disclosures%202015-16.xlsx.

10.7% reduction in MAR across all distributors for the 2020 distribution pricing year, all other factors being equal.[8]

The analysis assumes that distributors not subject to price regulation will behave in a manner that is similar to regulated businesses in relation to their pricing decisions (ie, they will pass on to their customers the savings in their costs associated with WACC).

The charts and tables in scenario 1 show that changes in the WACC could more than offset changes to the TPM.

The ‘status quo‘ is the current TPM and the current WACC for regulatory control period 2 (called RCP2) which is for 2015-2020. The charts and tables therefore do not provide a comparison with what would happen under the current TPM with a WACC adjustment.

In reality, by the time the revenue allowances for Transpower and distributors are reset in 2019 (to apply for 2020-2025), the MAR may vary from these modelled figures. This is because the WACC that will be applied will depend on interest rates that are applicable at the time and these may change from the most recent 2016 determination. Furthermore, other factors may also change that affect the revenue Transpower and distributors will be entitled to receive in the RCP3 period (2020-2025) such as the allowance provided for forecast expenditure.

NIGU investment remodelling

Ngawha generation has announced that it intends expanding its generation capacity by 25MW. Given the Authority intends that area-of-benefit (AoB) charges would be based on expected future benefits, the Authority has remodelled benefits from the NIGU investment, using vSPD, to reflect this expected change in capacity.

The inclusion of the additional Ngawha generation, and the improved modelling of Glenbrook’s response to high prices (discussed above), modifies the indicative AoB charges for the NIGU investment. These changes to Ngawha and Glenbrook may also affect the AoB charges for other investments. However, only the NIGU investment has been remodelled as this is the largest investment, and is most affected by the changes.

The remodelling of the NIGU investment produces lower overall benefits for the investment than in the second issues paper because the two adjustments described above reduce the demand served by this investment. The change also results in proportionately less of these benefits (and therefore charges) accruing to upper North Island (UNI) parties, and more to the rest of the load parties across New Zealand. This is because the reduction in net UNI load results in less of a ‘constraint’ benefit (which mainly UNI load benefits from) and more of a ‘losses’ benefit (which all load benefits from).

Application of capping mechanism

The Authority is proposing to cap transmission charges for distributors and direct consumers.

[8] This calculation assumes that electricity distribution businesses’ RAB in 2020 remains constant at the current level of $10,250 million. This is a simplifying assumption made for indicative purposes. For information on the current level of the EDBs’ total RAB see PWC, *Electricity Line Business, 2016 Information Disclosure Compendium*, p. 63, October 2016.

The proposed cap is expressed in relation to a base value for each year. For a distributor, the base value is the estimated total of the electricity bills (including all charges in respect of transmission, distribution, energy, levies and taxes[9]) of all the distributor's customers in the 2019/20 pricing year, plus inflation. For a direct consumer, the base value is the direct consumer's estimate total electricity bill in the 2019/2020 pricing year (including all charges in respect of transmission, energy, levies and taxes[10]), plus inflation (CPI).

The proposed cap is also expressed in relation to a "net charge".

For a distributor, the net charge will include the sum of the estimated electricity bills of all of the distributor's customers for the year (including all charges in respect of transmission, distribution, energy, levies, and taxes). For a direct consumer, the net charge will include the direct consumer's estimated electricity bill for the year (including all charges in respect of transmission, energy, levies and taxes).

In both cases, the net charge will be exclusive of any amount payable by the distributor or direct consumer for the year in respect of an LRMC charge, kvar charge, any charge attributable to assets commissioned after the end of the 2019/20 pricing year, any AoB charge for further assets included as eligible investments under the additional component, and any increase in the distributor's or direct consumer's uncapped charges as a result of the optimisation of an investment or a material change in circumstances.

The amount of the cap is:

(a) for each distributor, 103.5% of the distributor’s base value in that year

(b) for each direct consumer, 103.5% of the direct consumer's base value. The level of the cap for a direct consumer starts to rise by two percentage points per annum three years after the date the TPM comes into force (or when Transpower extends the AoB charge to other pre-guidelines assets if it does so and that occurs earlier). That is, in the first year the percentage increases, the cap rises to 105.5% of the direct consumer’s base value in that year, the next it rises to 107.5% of the direct consumer’s base value in that year, and so on.

This approach means distributors and direct consumers will see an increase in transmission charges that is:

- for a distributor, no more than 3.5% of the distributor's end customers estimated total electricity bills in the 2019/20 pricing year (plus inflation)
- for a direct consumer, no more than 3.5% of the direct consumer's estimated total electricity bill in the 2019/20 pricing year (plus inflation).

Modelling is indicative only

The modelling presented below necessarily makes assumptions and simplifications in some areas when estimating the impacts of the proposed TPM charges. For some variables, the modelling also relies on scaled historical market data, which may not be representative of future outcomes. Further, there are some aspects of the guidelines which can be interpreted and

9 Note that the modelling excludes GST.

10 Note that the modelling excludes GST.

applied in the final TPM in different ways. For these reasons the modelling is broadly indicative only.

The results of modelling scenarios 1 and 2 are shown below.

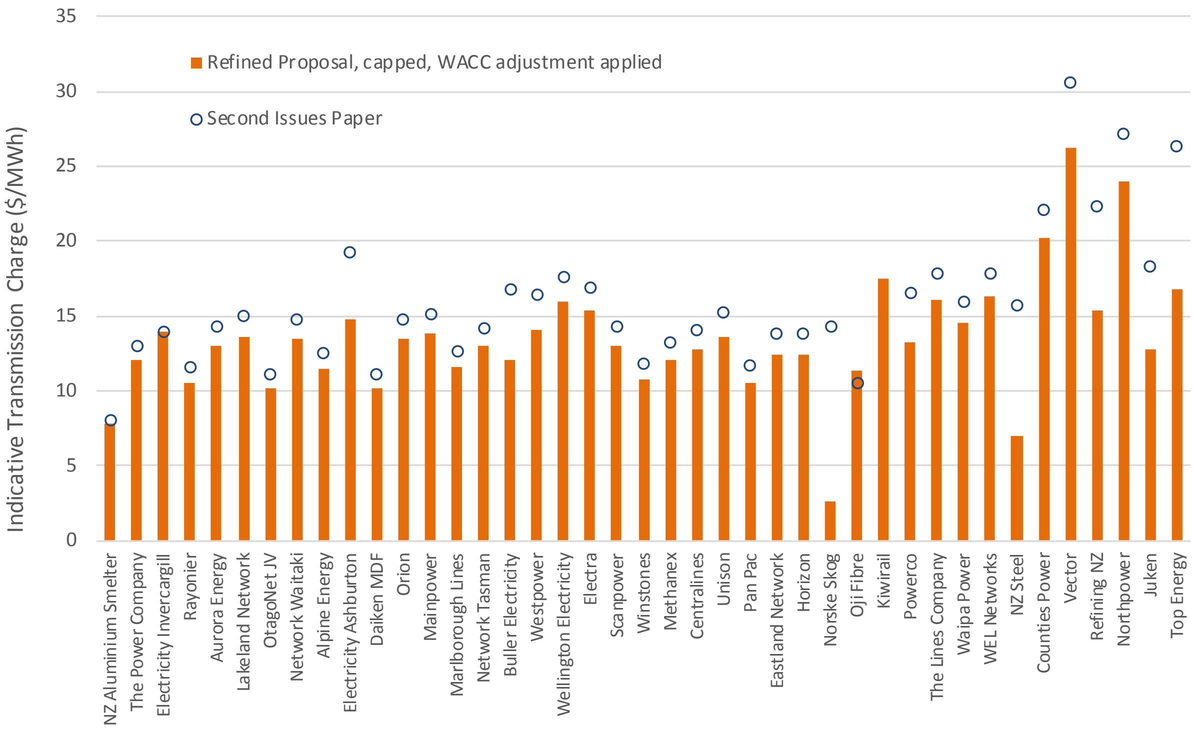
Modelling scenario 1 - impacts of all modelled changes

The charts and tables in this section show the impact in 2020 of the refined TPM proposal with all of the changes described above. Specifically, this includes the removal of known anomalies, updated NIGU AoB charges, the estimated reduction in the WACC based on current interest rates for Transpower and distributors to 5.32%, and the effect of the proposed capping mechanism.

The main changes to indicative transmission charges (shown as $/MWh) can be seen in Figure 1, with the circle markers showing the indicative charges arising from the proposals in the second issues paper and the orange columns showing the indicative charges of all of the proposed changes (ie, including the refinements discussed above), the cap and the estimated change in WACC. Relative to the proposal in the second issues paper, the refinements and the WACC reduction result in:

- a reduction to almost all parties' transmission charges due to the estimated reduction in Transpower's WACC
- a material reduction in parties' transmission charges where anomalies in the demand data have been addressed (eg, see Electricity Ashburton, Westpower, Buller)
- a material reduction in Top Energy's transmission charges arising from the remodelling of the NIGU investment with 25 MW added to Ngawha's generation[11]
- a reduction in proposed transmission charges for parties whose charges have been capped.

Figure 1 – Transmission charges as $/MWh with parties sorted geographically (all changes, 2020)[12]



[11] Other UNI parties who are allocated area of benefit charges from the NIGU investment also see a reduction in charges due to the remodelling of the NIGU investment. This occurs because flow into the entire UNI is constrained less often.

[12] KiwiRail has been left out due to scaling. Please refer to Tables 2 and 7 for KiwiRail's charges in $/MWh.

Figures 2 and 3 below show the transmission charges (expressed as $m/year, with the x-axis sorted alphabetically) with the same changes as discussed above. These charts also provide a comparison to the status quo charges (ie, the indicative charges that would apply if the TPM remains unchanged and the current WACC and revenue allowances apply). Figure 2 has the same data as Figure 3, but is shown with a different vertical scale (and with Vector removed) so that parties with lesser charges can be more easily seen.[13]

Figure 2 – Transmission charges as $m/year (all changes, 2020)

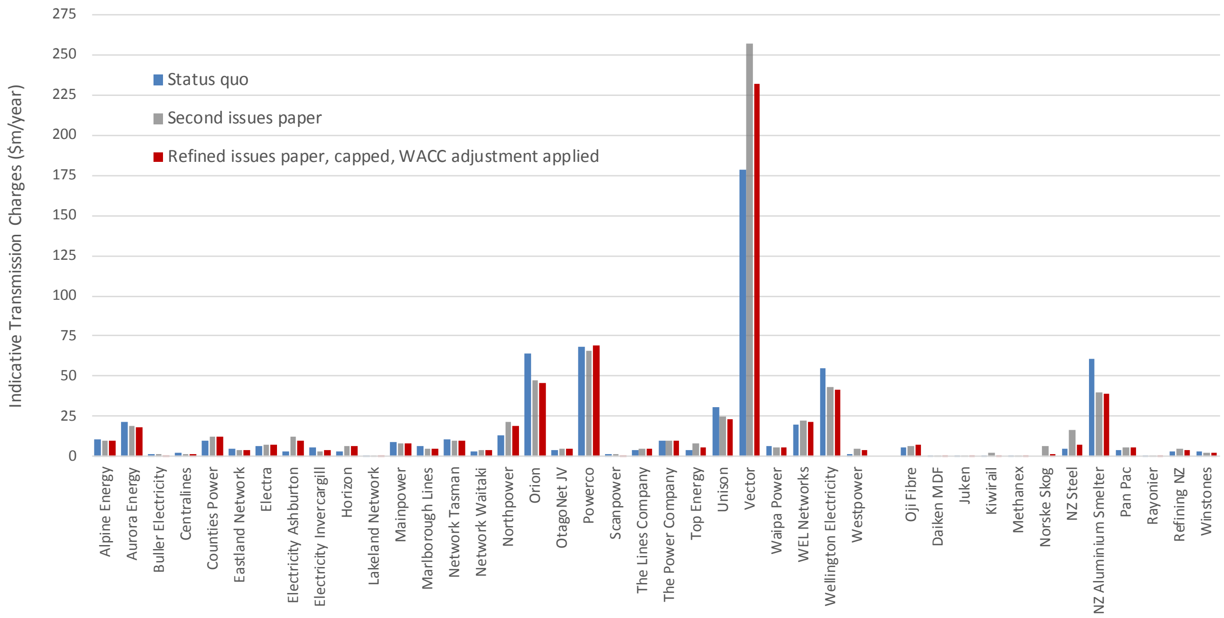
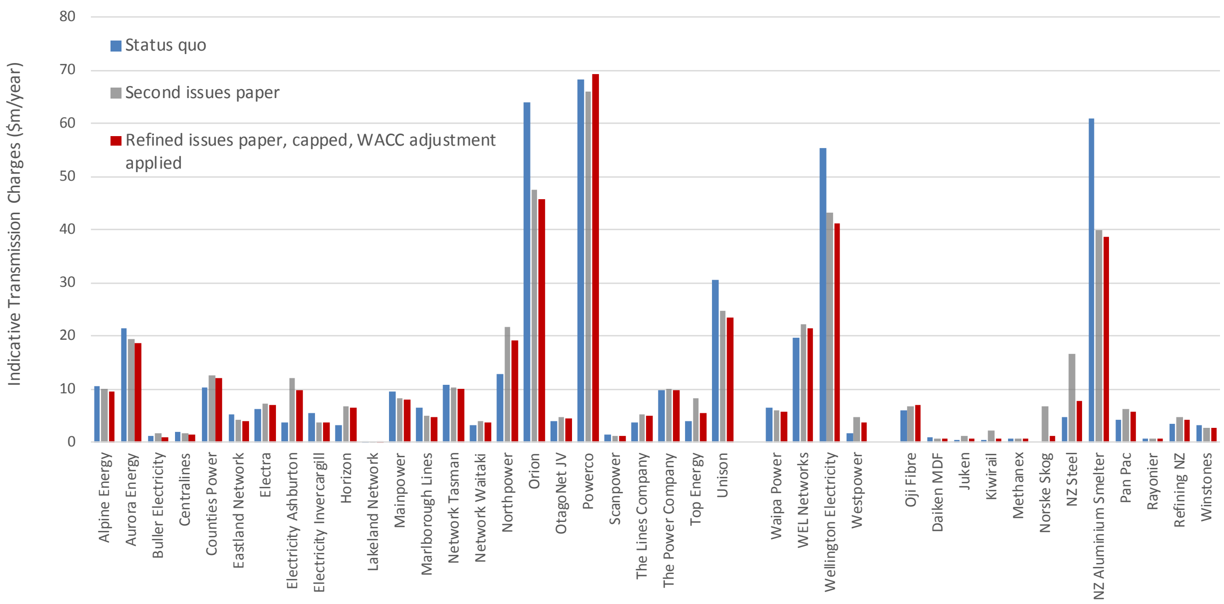


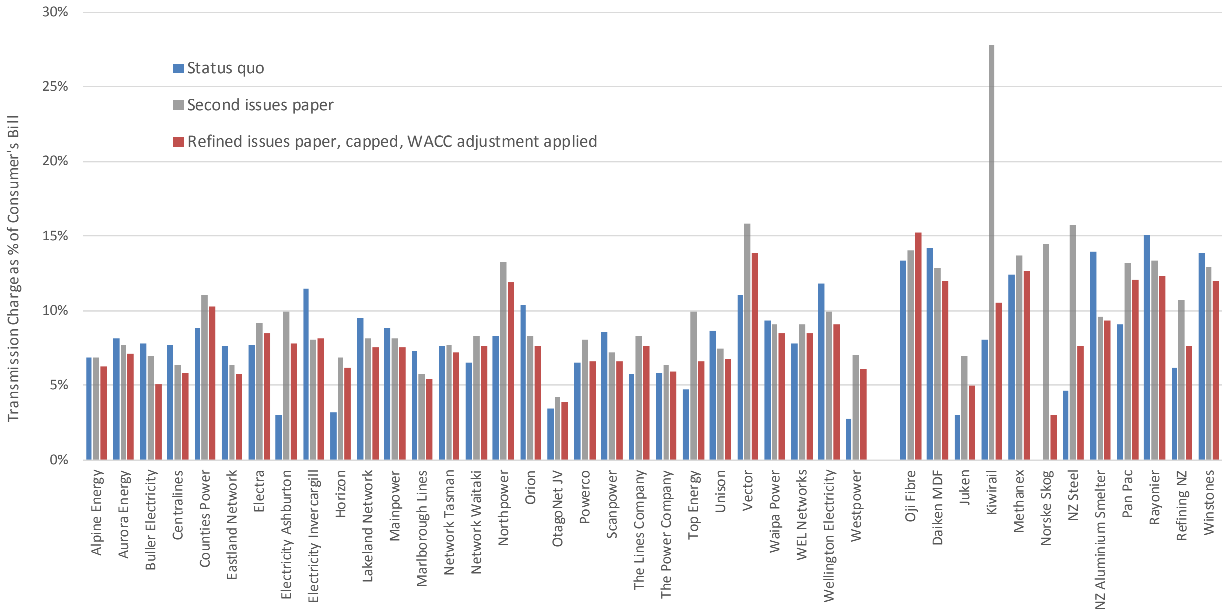
Figure 3 - Transmission charges as $m/year (all changes, 2020) – with the vertical scale changed and Vector not shown.



13 Lakeland Network charges are unchanged at $0.2 million per year under the status quo, the second issues paper and the refined issues paper. The values appear to be zero because of the scale of the charts.

Figure 4 below shows the same base data as that above, but the transmission charges are expressed as a percentage of total bills of consumers connected to a distributor's network (assuming that transmission charges are passed through to those consumers), and as a percentage of each direct connect consumer's total bill. We can see that the refined proposal has a moderating effect compared with both the second issues paper and the Status Quo.

Figure 4 - Transmission charge as a percentage of consumers' electricity bills (all changes, 2020)



The above charts have all focused on transmission charges only. However, a reduction in the WACC on distributors will reduce distribution charges, reducing the total electricity bills for consumers connected to the distributor's network (assuming that transmission charges are passed on to those consumers). The following charts show the combined impact of all these changes, first as the $/year impact on households' (ie, residential consumers') electricity bills (Figure 5) and then in Figure 6 relative to the status quo in which there are no changes to the TPM or to the WACC (ie, the status quo is the horizontal line, reflecting 0% change).

The bars in Figure 5 represent the estimated effect on households' electricity bills under each distributor (the reduced distributor WACC has a significant effect here). Commercial customers are not shown because they lack homogeneity as a customer group. The residential consumers' bills for each distributor have been estimated from the average residential retail electricity tariffs for each electricity network (as surveyed by the Ministry for Business, Innovation, and Employment).

In Figure 6 the direct connect consumers' charges comprise a transmission component, and an estimate of the energy component of the charge (modelled as 7.5 c/kWh for all parties).[14] The main result shown in this chart is the overall reduction in residential consumers' electricity bills, which mainly arises from the potential WACC reduction for Transpower and distributors. Further, approximately half of the directly connected industrial customers' charges are affected by the capping mechanism.

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14 The energy costs for parties will obviously vary depending on location, pattern of demand, and other factors. The 7.5 c/kWh is used as a simplifying assumption in the absence of better information.

Figure 5 – Indicative impact ($/year) on a typical household's electricity bill (all changes, 2020 impact)

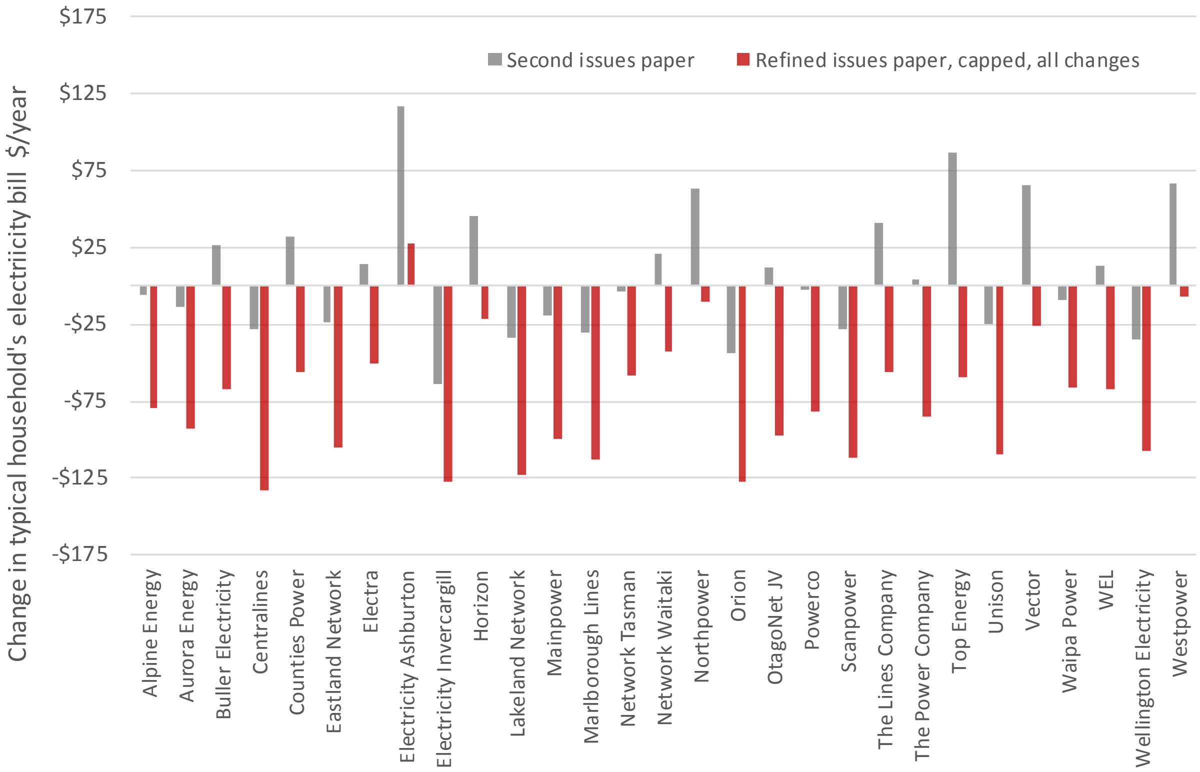
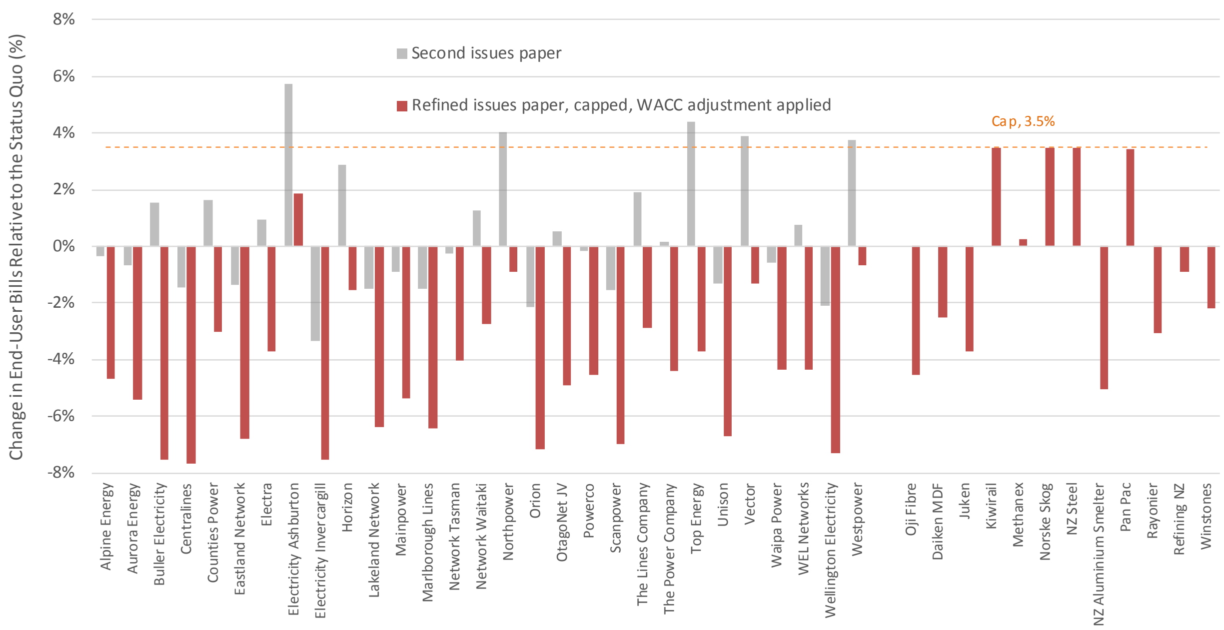


Figure 6 - Percentage change in consumers' electricity bills relative to status quo (all changes, 2020 impact)



The remainder of this section of the appendix contains the tables with the data for each of the above charts. The tables are in the same order as the charts (i.e. the first table below relates to Figure 2, not to the chart directly above.

Table 1 – Indicative transmission charges as $m/year (scenario 1, data for Figure 2)

Includes all the changes as described in this paper	Status quo charge	Second Issues Paper	Refined Second Issues Paper (all changes)
Alpine Energy	10.5	9.9	9.5
Aurora Energy	21.6	19.3	18.5
Buller Electricity	1.3	1.8	0.8
Centralines	2.0	1.6	1.5
Counties Power	10.2	12.5	12.0
Eastland Network	5.3	4.2	3.9
Electra	6.4	7.3	7.0
Electricity Ashburton	3.6	12.0	9.8
Electricity Invercargill	5.5	3.6	3.8
Horizon	3.2	6.9	6.5
Lakeland Network	0.2	0.2	0.2
Mainpower	9.5	8.3	8.0
Marlborough Lines	6.6	4.9	4.8
Network Tasman	10.7	10.3	10.0
Network Waitaki	3.2	4.0	3.8
Northpower	12.8	21.6	19.1
Orion	63.9	47.6	45.8
OtagoNet JV	4.0	4.7	4.5
Powerco	68.2	65.9	69.3
Scanpower	1.5	1.2	1.1
The Lines Company	3.7	5.2	4.9
The Power Company	9.7	10.1	9.8
Top Energy	3.8	8.3	5.4
Unison	30.5	24.8	23.4
Vector	178.8	256.9	231.7
Waipa Power	6.4	6.0	5.8
WEL Networks	19.7	22.1	21.4
Wellington Electricity	55.2	43.2	41.3
Westpower	1.6	4.7	3.7
Oji Fibre	6.0	6.7	7.0
Daiken MDF	0.9	0.8	0.7
Juken	0.44	1.13	0.7
Kiwirail	0.5	2.3	0.7
Methanex	0.7	0.7	0.7
Norske Skog	0.0	6.8	1.3
NZ Steel	4.6	16.6	7.8
NZ Aluminium Smelter	60.8	40.0	38.7
Pan Pac	4.3	6.2	5.9
Rayonier	0.7	0.6	0.6
Refining NZ	3.4	4.8	4.2
Winstones	3.2	2.8	2.7

Table 2 – Indicative transmission charges as $/MWh (scenario 1, data for Figure 1)

Includes all the changes as described in this paper	Status quo charge	Second Issues Paper	Refined Second Issues Paper (all changes)
Alpine Energy	12.6	12.5	11.5
Aurora Energy	15.2	14.3	13.1
Buller Electricity	19.1	16.8	12.1
Centralines	17.2	14.0	12.8
Counties Power	17.1	22.0	20.2
Eastland Network	16.7	13.8	12.4
Electra	14.0	16.9	15.4
Electricity Ashburton	5.5	19.2	14.8
Electricity Invercargill	20.4	13.9	14.0
Horizon	6.2	13.8	12.4
Lakeland Network	17.7	14.9	13.6
Mainpower	16.4	15.1	13.8
Marlborough Lines	16.1	12.6	11.6
Network Tasman	14.0	14.1	13.0
Network Waitaki	11.3	14.7	13.4
Northpower	16.1	27.1	24.0
Orion	18.8	14.7	13.5
OtagoNet JV	8.9	11.1	10.2
Powerco	13.1	16.6	13.3
Scanpower	17.3	14.2	13.0
The Lines Company	12.0	17.8	16.1
The Power Company	12.0	13.0	12.1
Top Energy	12.0	26.3	16.8
Unison	17.8	15.2	13.7
Vector	20.2	30.5	26.2
Waipa Power	16.3	15.9	14.6
WEL Networks	15.1	17.8	16.4
Wellington Electricity	21.3	17.5	15.9
Westpower	6.1	16.4	14.1
Oji Fibre	9.8	10.4	11.4
Daiken MDF	12.4	11.0	10.2
Juken	7.7	18.3	12.7
Kiwirail	13.0	57.2	17.5
Methanex	11.8	13.2	12.0
Norske Skog	0.0	14.3	2.7
NZ Steel	4.1	15.6	7.0
NZ Aluminium Smelter	12.2	8.0	7.8
Pan Pac	7.7	11.6	10.5
Rayonier	13.2	11.5	10.5
Refining NZ	12.3	22.3	15.4
Winstones	12.8	11.8	10.8

Table 3 – Transmission charges as a % of consumers' electricity bills (scenario 1)

Includes all the changes as described in this paper	Status Quo	Second issues paper	Refined Second Issues Paper (all changes)
Alpine Energy	6.9%	6.9%	6.3%
Aurora Energy	8.2%	7.7%	7.1%
Buller Electricity	7.8%	6.9%	5.1%
Centralines	7.7%	6.4%	5.9%
Counties Power	8.8%	11.1%	10.3%
Eastland Network	7.6%	6.4%	5.8%
Electra	7.8%	9.2%	8.5%
Electricity Ashburton	3.1%	9.9%	7.8%
Electricity Invercargill	11.5%	8.1%	8.1%
Horizon	3.2%	6.8%	6.2%
Lakeland Network	9.5%	8.2%	7.5%
Mainpower	8.8%	8.2%	7.5%
Marlborough Lines	7.3%	5.8%	5.4%
Network Tasman	7.7%	7.7%	7.2%
Network Waitaki	6.5%	8.3%	7.6%
Northpower	8.3%	13.2%	11.9%
Orion	10.4%	8.3%	7.7%
OtagoNet JV	3.4%	4.2%	3.9%
Powerco	6.5%	8.1%	6.6%
Scanpower	8.6%	7.2%	6.6%
The Lines Company	5.8%	8.3%	7.6%
The Power Company	5.9%	6.4%	5.9%
Top Energy	4.8%	9.9%	6.6%
Unison	8.7%	7.5%	6.8%
Vector	11.1%	15.8%	13.9%
Waipa Power	9.4%	9.1%	8.5%
WEL Networks	7.9%	9.1%	8.5%
Wellington Electricity	11.8%	9.9%	9.1%
Westpower	2.8%	7.0%	6.1%
Oji Fibre	13.4%	14.3%	15.2%
Daiken MDF	14.2%	12.9%	12.0%
Juken	3.1%	7.0%	5.0%
Kiwirail	8.1%	27.3%	10.6%
Methanex	12.4%	13.6%	12.6%
Norske Skog	0.0%	14.3%	3.1%
NZ Steel	4.7%	15.7%	7.7%
NZ Aluminium Smelter	14.0%	9.7%	9.4%
Pan Pac	9.1%	13.1%	12.1%
Rayonier	15.0%	13.4%	12.4%
Refining NZ	6.2%	10.8%	7.7%
Winstones	13.9%	12.9%	12.0%

Table 4 - Indicative impact ($/year) on a typical household's electricity bill relative to the status quo (scenario 1)

Indicative household impact relative to the status quo ($/year), (Refined issues paper, capped, all changes)	Second issues paper	Refined issues paper, capped, all changes
Alpine Energy	-6	-80
Aurora Energy	-14	-93
Buller Electricity	26	-67
Centralines	-29	-133
Counties Power	33	-56
Eastland Network	-24	-105
Electra	14	-50
Electricity Ashburton	117	28
Electricity Invercargill	-64	-128
Horizon	46	-22
Lakeland Network	-33	-123
Mainpower	-19	-100
Marlborough Lines	-31	-113
Network Tasman	-4	-58
Network Waitaki	21	-42
Northpower	63	-10
Orion	-44	-127
OtagoNet JV	12	-97
Powerco	-2	-82
Scanpower	-28	-111
The Lines Company	41	-56
The Power Company	4	-85
Top Energy	87	-60
Unison	-25	-109
Vector	66	-25
Waipa Power	-10	-67
WEL Networks	14	-67
Wellington Electricity	-35	-107
Westpower	66	-7

Table 5 – % change in consumers' electricity bills relative to status quo (scenario 1)

Includes all the changes as described in this paper	Second Issues Paper	Refined second issues paper, capped, all changes
Alpine Energy	-0.3%	-4.7%
Aurora Energy	-0.7%	-5.4%
Buller Electricity	1.5%	-7.6%
Centralines	-1.4%	-7.7%
Counties Power	1.6%	-3.0%
Eastland Network	-1.4%	-6.8%
Electra	1.0%	-3.7%
Electricity Ashburton	5.8%	1.9%
Electricity Invercargill	-3.4%	-7.5%
Horizon	2.9%	-1.5%
Lakeland Network	-1.5%	-6.4%
Mainpower	-0.9%	-5.4%
Marlborough Lines	-1.5%	-6.4%
Network Tasman	-0.2%	-4.1%
Network Waitaki	1.2%	-2.7%
Northpower	4.0%	-0.9%
Orion	-2.1%	-7.2%
OtagoNet JV	0.5%	-4.9%
Powerco	-0.1%	-4.5%
Scanpower	-1.6%	-7.0%
The Lines Company	1.9%	-2.9%
The Power Company	0.2%	-4.4%
Top Energy	4.4%	-3.7%
Unison	-1.3%	-6.7%
Vector	3.9%	-1.3%
Waipa Power	-0.6%	-4.4%
WEL Networks	0.8%	-4.4%
Wellington Electricity	-2.1%	-7.3%
Westpower	3.8%	-0.7%
Oji Fibre		-4.5%
Daiken MDF		-2.5%
Juken		-3.7%
Kiwirail		3.5%
Methanex		0.3%
Norske Skog		3.5%
NZ Steel		3.5%
NZ Aluminium Smelter		-5.1%
Pan Pac		3.4%
Rayonier		-3.1%
Refining NZ		-0.9%
Winstones		-2.2%

Modelling scenario 2 - results of capping and anomalies changes (no change to WACC)
The charts and tables in this section show the impact in 2020 of the new TPM with all the above changes except the effect of the estimated reduction in WACC that is assumed in scenario 1. Specifically, this includes the removal of known anomalies, updated NIGU AoB charges, and the effect of the proposed capping mechanism.

The main changes to proposed transmission charges (shown as $/MWh) can be seen in Figure 7, with the circle markers showing the indicative transmission charges arising from the proposals in the second issues paper, and the orange columns showing indicative charges expected from the refinements discussed in this paper (for 2020). Relative to the proposal in the second issues paper, the refinements result in:

- a material reduction in parties' proposed transmission charges where anomalies in the gross AMD data have been fixed (eg, see Electricity Ashburton, Westpower, Buller)
- a material reduction in Top Energy's charges arising from the recalculation of AoB charges for the NIGU investment with 25 MW added to Ngawha's generation
- a slight increase in proposed transmission charges for parties whose charges have not been capped (this is due to reallocation of transmission charges from capped parties).

Figure 7 – Transmission charges as $/MWh with parties sorted geographically (all changes except WACC, 2020)

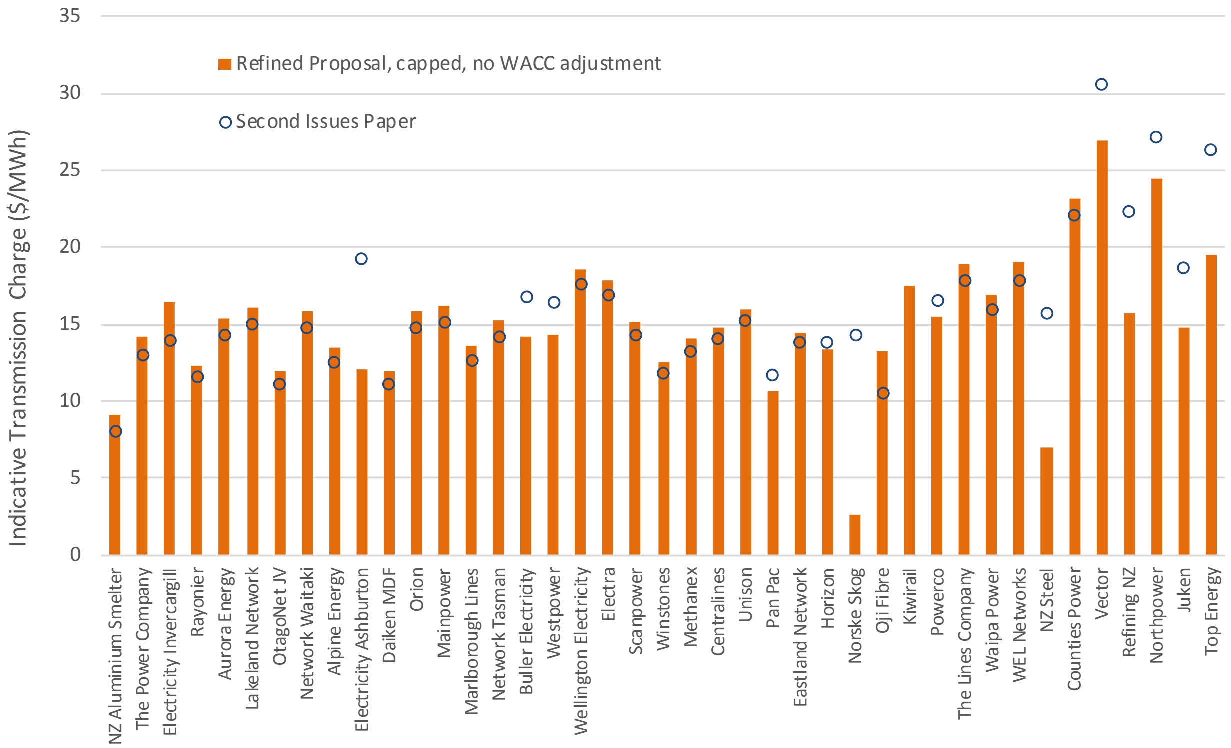


Figure 8 and Figure 9 below show the transmission charges (expressed as $m/year) with the same changes as discussed above. These charts also provide a comparison to the status quo charges (i.e. the indicative charges that would apply if the TPM proposal remains unchanged).

Figure 9 has the same data as Figure 8, but is shown with a different vertical scale (with Vector removed) such that parties with lesser charges can be more easily seen.

Figure 8 - Transmission charges as $m/year (all changes except WACC, 2020)

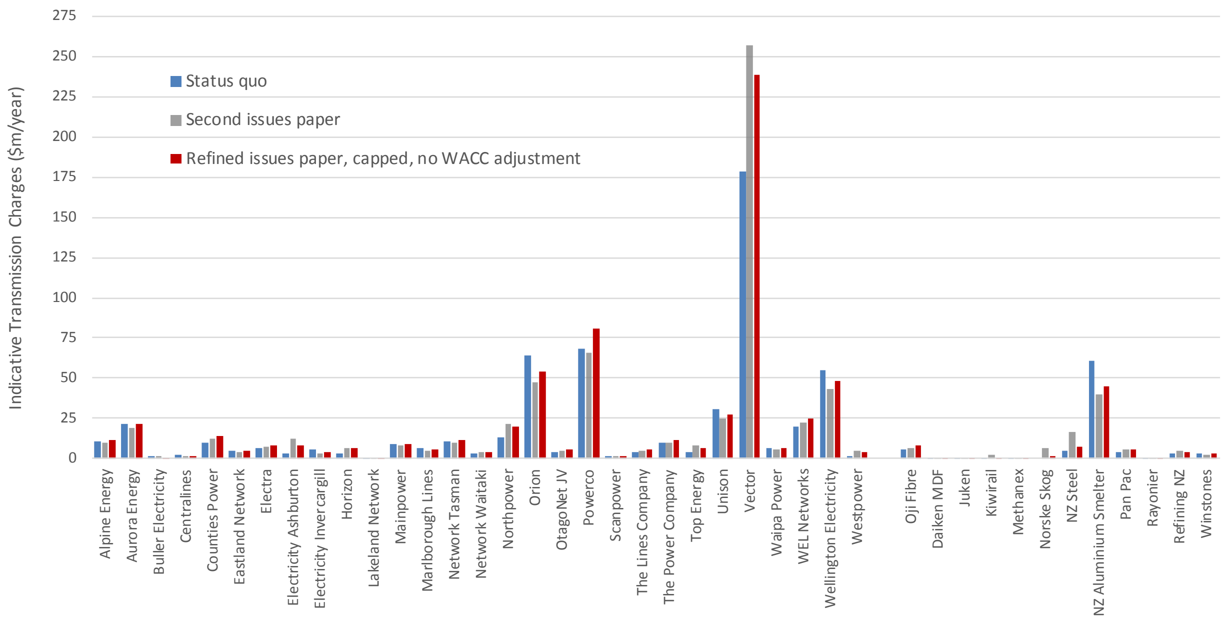


Figure 9 - Transmission charges as $m/year (all changes except WACC, 2020) – with the vertical scale changed

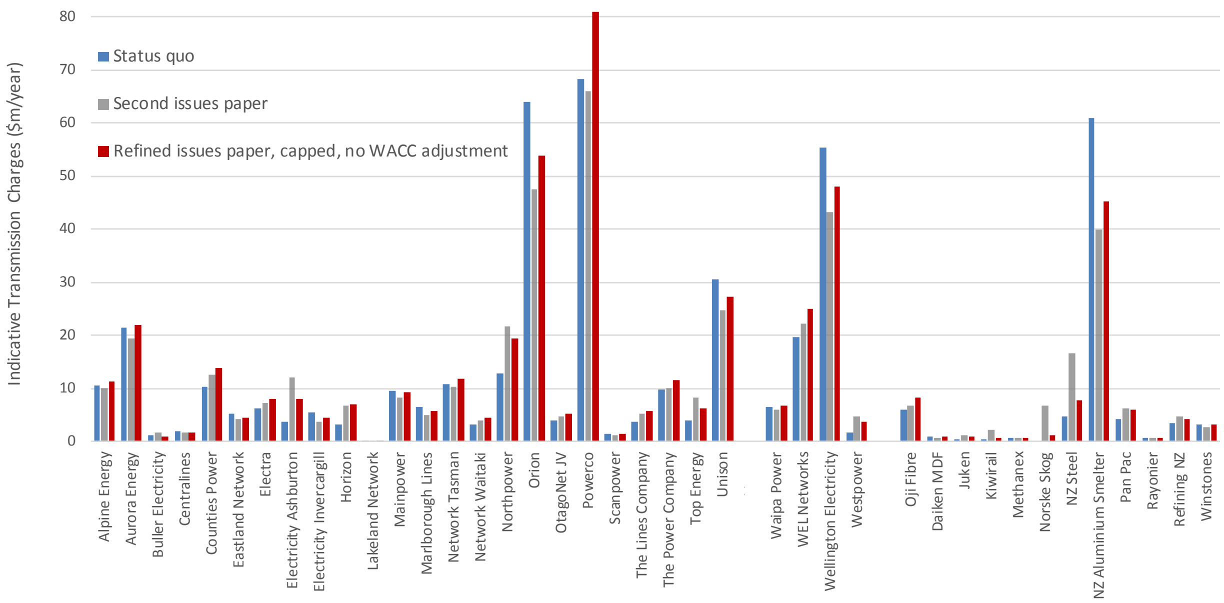
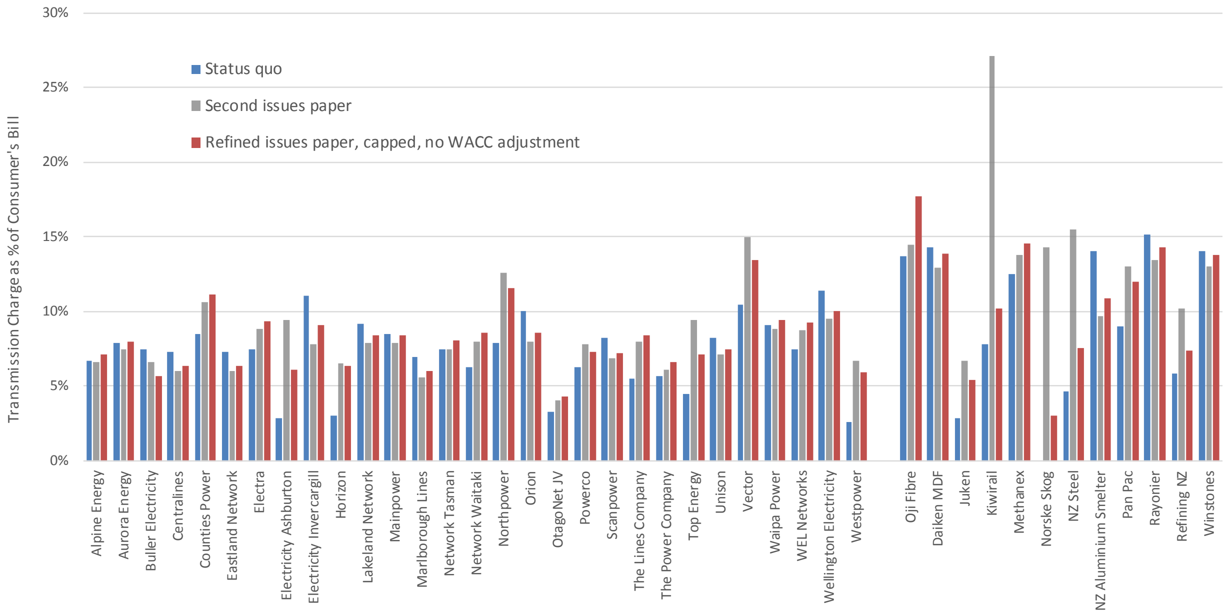


Figure 10 - Transmission charge as a percentage of consumers' electricity bills (all changes except WACC, 2020)



The preceding charts in this section have all focused on the change in the transmission charges only. The following charts show the impact of all the modelled changes on the estimated consumers' electricity bills relative to the status quo (ie, the status quo is the horizontal line, reflecting 0% change) in which there are no changes to the transmission or distributor WACCs.

The bars in Figure 11 represent the estimated effect on residential consumers' electricity bills under each distributor. Commercial customers are not shown because they lack homogeneity as a customer group. The residential consumers' bills for each distributor has been estimated from the average residential retail electricity tariffs for each electricity network (as surveyed by the Ministry for Business, Innovation, and Employment).

In Figure 12 the directly connected industrial parties' charges comprise the transmission component, and an estimate of the energy component of the charge (modelled as 7.5 c/kWh for all parties).[15] The main result shown in this chart is that the indicative charges have been moderated compared to those arising from the second issues paper. This has been mainly achieved through addressing the anomalies for distributors (only Electricity Ashburton reaches the cap in this scenario) and introducing the cap for directly connected industrial customers.

15 The energy costs for parties will obviously vary depending on location, pattern of demand, and other factors. The 7.5 c/kWh is used as a simplifying assumption in the absence of better information.

Figure 11 - Indicative impact ($/year) on a typical household's electricity bill (all changes except WACC, 2020 impact)

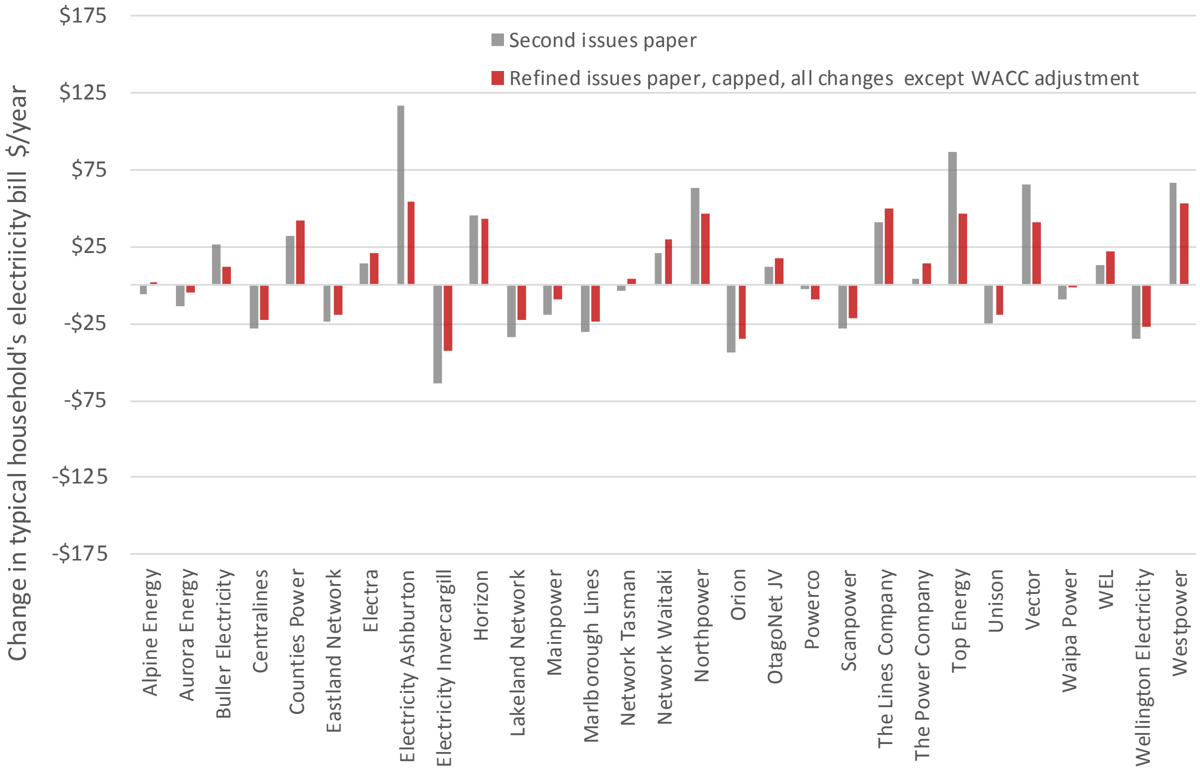
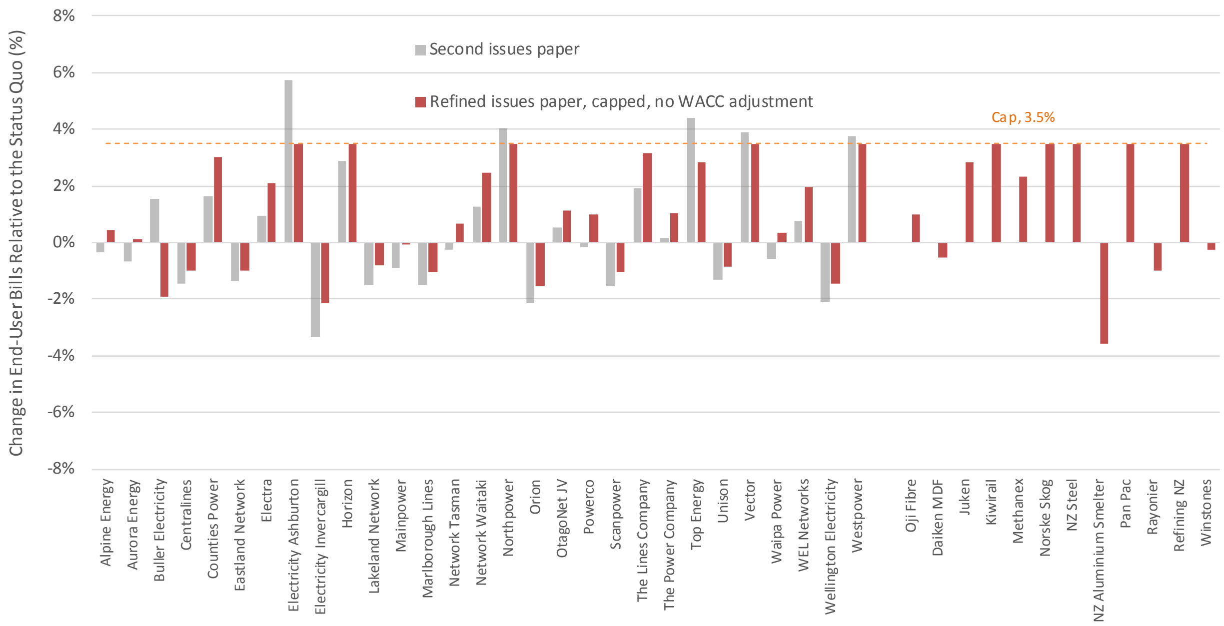


Figure 12 - Percentage change in consumers' electricity bills relative to status quo (all changes except WACC, 2020)



The remainder of this section of the appendix contains the tables with the data for each of the above charts. The tables are in the same order as the charts (i.e. the first table below relates to Figure 8, not to the chart directly above).

Table 6 – Indicative transmission charges as $m/year

Includes all changes except the change to WACC	Status quo charge	Second Issues Paper	Refined Second Issues Paper - no change to WACC
Alpine Energy	10.5	9.9	11.2
Aurora Energy	21.6	19.3	21.9
Buller Electricity	1.3	1.8	0.9
Centralines	2.0	1.6	1.8
Counties Power	10.2	12.5	13.8
Eastland Network	5.3	4.2	4.6
Electra	6.4	7.3	8.1
Electricity Ashburton	3.6	12.0	7.9
Electricity Invercargill	5.5	3.6	4.4
Horizon	3.2	6.9	7.0
Lakeland Network	0.2	0.2	0.2
Mainpower	9.5	8.3	9.4
Marlborough Lines	6.6	4.9	5.6
Network Tasman	10.7	10.3	11.7
Network Waitaki	3.2	4.0	4.5
Northpower	12.8	21.6	19.5
Orion	63.9	47.6	53.8
OtagoNet JV	4.0	4.7	5.3
Powerco	68.2	65.9	80.8
Scanpower	1.5	1.2	1.3
The Lines Company	3.7	5.2	5.8
The Power Company	9.7	10.1	11.5
Top Energy	3.8	8.3	6.3
Unison	30.5	24.8	27.3
Vector	178.8	256.9	238.1
Waipa Power	6.4	6.0	6.7
WEL Networks	19.7	22.1	24.9
Wellington Electricity	55.2	43.2	48.1
Westpower	1.6	4.7	3.7
Oji Fibre	6.0	6.7	8.2
Daiken MDF	0.9	0.8	0.9
Juken	0.4	1.1	0.9
Kiwirail	0.5	2.3	0.7
Methanex	0.7	0.7	0.8
Norske Skog	0.0	6.8	1.3
NZ Steel	4.6	16.6	7.8
NZ Aluminium Smelter	60.8	40.0	45.3
Pan Pac	4.3	6.2	5.9
Rayonier	0.7	0.6	0.7
Refining NZ	3.4	4.8	4.3
Winstones	3.2	2.8	3.1

Table 7 – Indicative transmission charges as $/MWh

Includes all changes except the change to WACC	Status quo charge	Second Issues Paper	Refined Second Issues Paper - no change to WACC
Alpine Energy	12.6	12.5	13.5
Aurora Energy	15.2	14.3	15.4
Buller Electricity	19.1	16.8	14.2
Centralines	17.2	14.0	14.8
Counties Power	17.1	22.0	23.2
Eastland Network	16.7	13.8	14.5
Electra	14.0	16.9	17.9
Electricity Ashburton	5.5	19.2	12.0
Electricity Invercargill	20.4	13.9	16.4
Horizon	6.2	13.8	13.3
Lakeland Network	17.7	14.9	16.1
Mainpower	16.4	15.1	16.3
Marlborough Lines	16.1	12.6	13.6
Network Tasman	14.0	14.1	15.3
Network Waitaki	11.3	14.7	15.8
Northpower	16.1	27.1	24.5
Orion	18.8	14.7	15.8
OtagoNet JV	8.9	11.1	12.0
Powerco	13.1	16.6	15.5
Scanpower	17.3	14.2	15.1
The Lines Company	12.0	17.8	18.9
The Power Company	12.0	13.0	14.2
Top Energy	12.0	26.3	19.5
Unison	17.8	15.2	16.0
Vector	20.2	30.5	26.9
Waipa Power	16.3	15.9	16.9
WEL Networks	15.1	17.8	19.0
Wellington Electricity	21.3	17.5	18.6
Westpower	6.1	16.4	14.3
Oji Fibre	9.8	10.4	13.3
Daiken MDF	12.4	11.0	11.9
Juken	7.7	19.5	14.8
Kiwirail	13.0	57.2	17.5
Methanex	11.8	13.2	14.0
Norske Skog	0.0	14.3	2.7
NZ Steel	4.1	15.6	7.0
NZ Aluminium Smelter	12.2	8.0	9.1
Pan Pac	7.7	11.6	10.6
Rayonier	13.2	11.5	12.3
Refining NZ	12.3	22.3	15.7
Winstones	12.8	11.8	12.6

Table 8 – Transmission charges as a percentage of consumers' electricity bills

Includes all changes except the change to WACC	Status quo	Second issues paper	Refined Second Issues Paper, no change to WACC
Alpine Energy	6.7%	6.6%	7.1%
Aurora Energy	7.9%	7.4%	8.0%
Buller Electricity	7.5%	6.6%	5.7%
Centralines	7.3%	6.0%	6.4%
Counties Power	8.5%	10.6%	11.1%
Eastland Network	7.3%	6.1%	6.4%
Electra	7.4%	8.8%	9.3%
Electricity Ashburton	2.9%	9.4%	6.1%
Electricity Invercargill	11.0%	7.8%	9.1%
Horizon	3.0%	6.5%	6.3%
Lakeland Network	9.1%	7.8%	8.4%
Mainpower	8.5%	7.8%	8.4%
Marlborough Lines	7.0%	5.6%	6.0%
Network Tasman	7.4%	7.5%	8.1%
Network Waitaki	6.3%	8.0%	8.6%
Northpower	7.9%	12.7%	11.5%
Orion	10.0%	8.0%	8.6%
OtagoNet JV	3.2%	4.0%	4.3%
Powerco	6.3%	7.8%	7.3%
Scanpower	8.2%	6.9%	7.3%
The Lines Company	5.5%	8.0%	8.4%
The Power Company	5.6%	6.1%	6.6%
Top Energy	4.5%	9.4%	7.2%
Unison	8.3%	7.1%	7.5%
Vector	10.5%	15.1%	13.5%
Waipa Power	9.1%	8.8%	9.4%
WEL Networks	7.5%	8.7%	9.3%
Wellington Electricity	11.3%	9.5%	10.1%
Westpower	2.6%	6.7%	5.9%
Oji Fibre	13.7%	14.6%	17.7%
Daiken MDF	14.3%	12.9%	13.9%
Juken	2.9%	7.0%	5.4%
Kiwirail	7.8%	26.6%	10.2%
Methanex	12.5%	13.7%	14.5%
Norske Skog	0.0%	14.1%	3.0%
NZ Steel	4.6%	15.5%	7.6%
NZ Aluminium Smelter	14.1%	9.7%	10.9%
Pan Pac	9.0%	12.9%	12.0%
Rayonier	15.2%	13.4%	14.3%
Refining NZ	5.9%	10.3%	7.4%
Winstones	14.0%	13.0%	13.8%

Table 9 - Indicative impact ($/year) on a typical household's electricity bill relative to the status quo

Indicative household impact relative to the status quo ($/year), (Refined issues paper, capped, all changes except WACC adjustment)	Second issues paper	Refined issues paper, capped, no change to WACC
Alpine Energy	-6	2
Aurora Energy	-14	-4
Buller Electricity	26	13
Centralines	-29	-23
Counties Power	33	42
Eastland Network	-24	-20
Electra	14	21
Electricity Ashburton	117	54
Electricity Invercargill	-64	-43
Horizon	46	43
Lakeland Network	-33	-22
Mainpower	-19	-9
Marlborough Lines	-31	-23
Network Tasman	-4	4
Network Waitaki	21	30
Northpower	63	47
Orion	-44	-34
OtagoNet JV	12	18
Powerco	-2	-9
Scanpower	-28	-22
The Lines Company	41	50
The Power Company	4	14
Top Energy	87	46
Unison	-25	-20
Vector	66	41
Waipa Power	-10	-1
WEL Networks	14	22
Wellington Electricity	-35	-27
Westpower	66	53

Table 10 – Percentage change in consumers' electricity bills relative to the status quo

Includes all changes except the change to WACC	Second Issues Paper	Refined issues paper, capped, no WACC adjustment
Alpine Energy	-0.3%	0.5%
Aurora Energy	-0.7%	0.1%
Buller Electricity	1.5%	-1.9%
Centralines	-1.4%	-1.0%
Counties Power	1.6%	3.0%
Eastland Network	-1.4%	-1.0%
Electra	1.0%	2.1%
Electricity Ashburton	5.8%	3.5%
Electricity Invercargill	-3.4%	-2.2%
Horizon	2.9%	3.5%
Lakeland Network	-1.5%	-0.8%
Mainpower	-0.9%	-0.1%
Marlborough Lines	-1.5%	-1.0%
Network Tasman	-0.2%	0.7%
Network Waitaki	1.2%	2.5%
Northpower	4.0%	3.5%
Orion	-2.1%	-1.6%
OtagoNet JV	0.5%	1.1%
Powerco	-0.1%	1.0%
Scanpower	-1.6%	-1.0%
The Lines Company	1.9%	3.1%
The Power Company	0.2%	1.0%
Top Energy	4.4%	2.8%
Unison	-1.3%	-0.9%
Vector	3.9%	3.5%
Waipa Power	-0.6%	0.4%
WEL Networks	0.8%	1.9%
Wellington Electricity	-2.1%	-1.5%
Westpower	3.8%	3.5%
Oji Fibre		1.0%
Daiken MDF		-0.5%
Juken		2.8%
Kiwirail		3.5%
Methanex		2.3%
Norske Skog		3.5%
NZ Steel		3.5%
NZ Aluminium Smelter		-3.6%
Pan Pac		3.5%
Rayonier		-1.0%
Refining NZ		3.5%
Winstones		-0.2%