Modelling of caps and transitions for the TPM options working paper

26 Jun 2015

This document describes four alternatives for capping or transitioning transmission charges, under the options in the Authority's TPM options working paper.[1]

All the analysis in this document refers to the scenario described in Appendix A of the options working paper (in which targeted charges are applied to existing and new assets and investments). The Authority has not modelled caps or transitions for Application B (in which targeted charges are applied to new assets and investments only). This is because, under Application B, transmission charges would not be expected to differ greatly from status quo TPM charges in the initial years following changes to the TPM.

The Authority does not intend there to be any cap or transition on connection charges (as opposed to deeper connection charges). At this stage, the Authority is not proposing any changes to the connection charge.

The four alternatives

Four alternatives are discussed in this document: a cap and three transitions. They are the four alternatives described in Section 12 of the options working paper, with two modifications:

- a small change has been made to the way in which the costs of transition are recovered under Alternative 2
- under Alternative 4, the capacity-based residual charge is now transitioned over five years.

Alternative 1: a cap

Under Alternative 1, electricity distribution business (EDB) charging rates (in fully variabilised terms) are capped at the upper quartile of pre-capping charging rates, ie about $22.50/MWh. The cap does not apply to charges for the costs of new assets or investments (ie, those commissioned or approved (or both) after the new TPM Guidelines are published) as the charges for these assets would be implemented immediately.

The cost of the cap (modelled as about $95 million per year, in the scenario) is recovered from other EDBs, with each EDB paying an amount that reflects the extent to which its pre-capped charging rate is below the cap.

(This cap could apply for a limited time period, eg three years, as otherwise some EDBs would never fully transition.)

[1] http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c15374

Alternative 2: a transition

Under Alternative 2, the charging rates to EDBs (in fully variabilised terms) may not increase by more than $12.50/MWh per year, or roughly 5% of a typical retail tariff. This limit does not apply to charges for the costs of new assets or investments as the charges for these assets would be implemented immediately.

The cost of the transition (modelled as about $3 million per year, in the scenario) is recovered through a small per-MWh charge on all EDBs. This is a minor change from the options paper, which described the cost as being recovered from EDBs whose charging rates increased by less than $12.50/MWh per year.

Alternative 3: a transition

Under Alternative 3, charging rates on load customers (in fully variabilised terms) may not increase by more than 20% per year. This limit does not apply to charges for the costs of new assets or investments, as the charges for these assets would be implemented immediately.

The cost of the transition (modelled as about $50 million per year, in the scenario) is recovered from load customers for which the charging rate is lower than it would have been under the status quo.

Alternative 4: a transition

Under Alternative 4, old charges (RCPD and HVDC) are phased out, and new charges (deeper connection, area of benefit, capacity-based residual, etc) are phased in linearly over a five-year period. The transition does not apply to charges for the costs of new assets or investments, which would be implemented immediately.

Section 12 of the options working paper did not identify the capacity-based residual charge as being transitioned over five years, but that is what is intended.

Impact on residential households

Table 1 shows modelled charges on mass-market load, by electricity distribution business (EDB) area, for:

- the status quo
- the Base Option, under the four alternatives for capping or transitioning transmission charges
- the Base Option, with no cap or transition.

The table shows the modelled transmission charge that would be passed on to a typical household, in dollars per year (excluding GST).

The charges shown are averaged over the three years of the scenario. For the transition options, these are the first three years of the transition; in subsequent years, the transition would be complete or near-complete, and charges would be more similar to those under the 'no transition or cap' column.

Key assumptions are that:

- all transmission charges on EDBs would be passed on from distributors to retailers, and retailers to customers, on a per-MWh basis
- all customer classes in a given EDB area would face the same transmission charge in per-MWh terms
- a typical household would consume the following quantity of electricity: [2]

EDB area	Typical household electricity consumption (kWh per year)	EDB area	Typical household electricity consumption (kWh per year)
Alpine Energy	8,339	Orion	8,790
Aurora Energy	8,233	Powerco	6,371
Buller Electricity	5,481	PowerNet	7,993
Counties Power	7,998	Scanpower	7,110
Eastland Network	6,319	The Lines Company	8,033
Electra	6,465	Top Energy	6,065
Electricity Ashburton	8,725	Unison	7,101
Horizon	6,322	Vector	7,119
Mainpower	8,887	Waipa Power	7,648
Marlborough Lines	7,215	WEL	7,026
Network Tasman	6,979	Wellington Electricity	7,160
Network Waitaki	7,577	Westpower	6,151
Northpower	6,369		

[2] Unpublished Electricity Authority data for 2014, based on Registry information. The Authority plans to publish these data on EMI.

Assumptions have also been made about the total amount of electricity consumption in each EDB area. (The more consumption in the area, the lower the charge on each individual MWh of consumption, all else being equal.)

The analysis does not take into account that some EDBs make ACOT payments to embedded generators. As a result, 'status quo' charges may appear anomalously low for networks that include substantial amounts of embedded generation, relative to their amount of load (such as Top Energy or Westpower).

Furthermore, the impact under the capping or transition options do not take into account that:

- consumers, including residential consumers, that would pay higher charges have also gained greater benefits from recent major transmission investment (ie reduced prices and improved reliability)
- the Authority's proposals would be expected to lead to more efficient investment, and hence to place downward pressure on costs faced by all parties in the mid- to long-term.

Table 1: Modelled charges on mass-market load, as $ per year for a typical household, under the Base Option of Application A

EDB area	Status quo	Alternative 1: a cap	Alternative 2: a transition	Alternative 3: a transition	Alternative 4: a transition	No transition or cap
Alpine Energy	119	145	91	102	105	91
Aurora Energy	122	154	116	118	117	115
Buller Electricity	77	104	81	80	77	80
Counties Power	118	(*) 203	217	192	169	217
Eastland Network	115	139	135	134	120	134
Electra	100	145	146	137	116	145
Electricity Ashburton	62	144	77	76	66	76
Horizon	33	107	63	49	44	63
Mainpower	159	173	140	147	148	139
Marlborough Lines	120	162	196	171	148	195
Network Tasman	97	132	101	100	96	100
Network Waitaki	113	134	88	98	101	88
Northpower	100	143	185	146	133	187
Orion	179	161	115	140	149	114
Powerco	104	130	113	113	105	113
PowerNet *(incl The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)*	116	146	89	99	110	88
Scanpower	125	140	115	118	118	114
The Lines Company	106	157	128	128	113	128
Top Energy	82	136	202	120	137	223
Unison *(incl Centralines)*	130	139	113	119	120	112
Vector	142	163	225	202	174	225
Waipa Power	129	139	98	109	113	97
WEL	115	133	101	106	106	100
Wellington Electricity	157	141	116	131	137	115
Westpower	50	138	168	73	104	187

(*) The relatively high rate paid by households in the Counties Power area under Alternative 1 arises because Counties Power is modelled as paying the costs of a hypothetical new investment reinforcing Otahuhu – Wiri. Because the Otahuhu – Wiri upgrade is modelled as taking place after the new Guidelines are published, charges with respect to this investment are not subject to the cap.

Charging rates for major consumers and generators

Table 2 shows modelled charging rates (in fully variabilised terms), for:

- the status quo
- the Base Option, under the four alternatives for capping or transitioning transmission charges,
- the Base Option, with no cap or transition.

Unlike Table 1, Table 2 includes only major consumers and generators.

Also unlike Table 1, the figures in Table 2 refer to charging rates in $/MWh.

The charging rates shown are averaged over the three years of the scenario. For the transition options, these are the first three years of the transition – in subsequent years, the transition would be complete or near-complete, and charging rates would be more similar to those under the 'no transition or cap' column.

Some geothermal power plants (such as Nga Awa Purua) are separated out for ease of reference.

Some industrial consumers are also separated out for ease of reference, even though, in practice, their transmission charges might be paid indirectly through a network or retailer.

Some generators with relatively small injection quantities are omitted.

Table 2: Charging rates under the Base Option of Application A ($/MWh)

	Status quo	Alternative 1: a cap	Alternative 2: a transition	Alternative 3: a transition	Alternative 4: a transition	No transition or cap
Generators						
Contact	2.5	3.3	3.3	3.3	3.2	3.3
Genesis	0.9	1.3	1.3	1.3	1.1	1.3
Meridian	7.9	4.2	4.2	4.2	6.7	4.2
Mokai JV	0.0	0.6	0.6	0.6	0.3	0.6
MRP	0.0	0.7	0.7	0.7	0.4	0.7
NAP JV	0.0	1.5	1.5	1.5	0.7	1.5
Ngatamariki	0.0	1.4	1.4	1.4	0.7	1.4
Todd	0.0	1.1	1.1	1.1	0.5	1.1
Trustpower	1.4	2.0	2.0	2.0	1.7	2.0
Major industrials						
CHH	7.0	2.3	2.3	4.1	5.0	2.3
Daiken MDF	12.1	2.6	2.6	6.3	8.0	2.6
Kiwirail	12.0	4.1	4.1	7.2	8.6	4.1
Methanex	12.0	4.5	4.5	7.5	8.7	4.5
Norske Skog	0.0	2.2	2.2	0.0	0.9	2.2
NZ Steel	8.6	1.7	1.7	4.4	5.7	1.7
NZAS	12.4	1.5	1.5	5.8	7.8	1.5
Pacific Steel	17.9	5.3	5.3	10.2	12.9	5.3
PanPac	4.2	2.3	2.3	3.1	3.4	2.3
Rayonier	12.7	7.0	7.0	9.3	(*) 13.2	7.0
Winstones	13.0	1.4	1.4	6.0	8.1	1.4

(*) The relatively high value for Rayonier under Alternative 4 stems from the relatively high contribution (in $/MWh terms) that Rayonier is assumed to make to recovering the costs of the LSI Reliability upgrade, under the deeper connection method. Because the LSI Reliability upgrade is modelled as being completed after the new Guidelines are published, charges with respect to this investment are not transitioned.