Demand and generation sensitivities for the TPM options working paper

6 August 2015

This document describes four sensitivities that have been modelled by the Authority, representing different levels of demand growth and/or generation investment. The document should be read in conjunction with the Authority's TPM options working paper,[1] the deeper connection companion paper,[2] and the document 'TPM options working paper – revisions to indicative modelling'.[3]

The four sensitivities represent:

- higher demand
- lower demand
- new generation in Northland
- new generation on the West Coast of the South Island.

The Authority had indicated in the TPM options working paper that it planned to publish the high and low demand sensitivities during the consultation period. For these sensitivities, the distribution of charges is shown for the deeper connection charge on pre-2017 assets,[4] and for all charges combined.

The Authority was asked by stakeholders to prepare the new generation scenarios. For these sensitivities, the distribution of charges is shown for the deeper connection charge on pre-2017 assets only.

The results shown in this document apply to the Base Option under Application A, and do not include any caps or transitions.

Note that references to the 'base case' in this document refer to the version of the analysis that was published in the options working paper – not to be confused with the 'Base Option', which is one of the three options discussed in the working paper.

All results shown are net of LCE (that is, they are lower than they would be if there were no rentals to offset transmission charges). kVar and connection charges are not included.

The modelling included in this document provides the estimated/indicative impact of the options, and applications, as outlined above. The actual impact of any changes

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

[2] https://www.ea.govt.nz/dmsdocument/19471

[3] http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/development/tpm-options-working-paper-and-related-documents-revisions-to-indicative-modelling/

[4] These are the assets for which costs may be recovered through the deeper connection charge under Application A, but not under Application B. Under Application A, they make up over 90% of deeper connection charges.

to the transmission pricing regime will depend on the guidelines published by the Authority (if any), and on how Transpower gives effect to those guidelines in drafting a new TPM.

The modelling included in this document assumes that charges for each deeper connection asset are allocated between nodes that are deemed to be ‘connected by’ the asset in proportion to their anytime maximum demand (AMD) or anytime maximum injection (AMI). This is one of six allocators that are discussed in the deeper connection companion paper. The choice of allocator could materially alter the financial impact of the deeper connection charges and the impact of generation scenarios on the allocation of deeper connection charges. The Authority has not yet decided which allocator is best. In making this decision, the Authority will seek to choose an allocator that avoids inefficient avoidance of deeper connection charges.

High and low demand scenarios

Input assumptions

In the high demand scenario, demand at all nodes except Tiwai and Kawerau is scaled up by:

- 2.5% in 2017
- 3.5% in 2018
- 4.5% in 2019

relative to the base case. Further, an additional 100 MW of geothermal generation is added during the scenario.

In the low demand scenario, demand at all nodes except Tiwai and Kawerau is scaled down by the same factors – ie:

- 2.5% in 2017
- 3.5% in 2018
- 4.5% in 2019

relative to the base case. Further, the amount of geothermal generation added during the scenario is reduced by 50 MW (relative to the base case).

An exception is that *negative* demands (eg, embedded generation injecting into the grid) are not scaled in either of these scenarios.

These changes to demand are modelled in vSPD and lead to changes in generation output. The Authority has used the same generation offers as in the base case.

All other input assumptions are the same as in the base case. In particular, the Authority has assumed that transmission investment, and Transpower's recoverable costs, are the same as in the base case. In practice, reduced demand growth would tend to drive transmission costs downwards, resulting in a reduction in Transpower's recoverable costs. However, such cost reductions might not occur until partway through, or after the end of, the modelled period.

Results

Table 1 shows how these sensitivities affect the modelled allocation of deeper connection charges.

For most parties, there is little difference between the base case and the high and low demand scenarios. In other words, the deeper connection approach is robust to across-the-board increases or reductions in demand (as is the current interconnection charge).

Some exceptions, highlighted in **bold** in the table, are that:

- Aurora is modelled as paying $0.5 million per year more in the low demand scenario than in the base case[5]
- Contact is modelled as paying $0.8 million per year more in the high demand scenario, [6] and $1.5 million per year less in the low demand scenario.[7]

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5 Largely because Aurora pays a higher share of the cost of a transformer at Cromwell, which under the base case is mainly paid by Contact. This, in turn, is because Clyde's flow share through the transformer falls below the 3% cutoff in the low demand scenario (and the Clyde generation station is owned by Contact).

6 Largely because Contact pays a higher share of the cost of the Wairakei Ring and the transmission link from Stratford to Huntly. The former is because Contact is assumed to construct more geothermal generation in the area in the high demand scenario; the latter is because the HHI of the link is lower in the high demand scenario than in the base case.

7 Largely because Contact pays a lower share of the cost of the Wairakei Ring, a transformer at Cromwell and the transmission link from Stratford to Huntly (all for the same reasons as given above), as well as the link from Roxburgh to Naseby (because Clyde's flow share through the link falls below the 3% cutoff).

Table 1: Comparison of deeper connection charges on pre-2017 assets, between the base case and the high and low demand scenarios

	Base case (average $M per year)	High demand (average $M per year)	As % of base case	Difference from base case	Low demand (average $M per year)	As % of base case	Difference from base case
EDBs							
Alpine Energy	0.79	0.79	100%	<0.01	0.79	100%	<0.01
Aurora Energy	0.49	0.50	102%	0.01	**1.01**	**207%**	**0.52**
Buller Electricity	0.73	0.73	100%	<0.01	0.73	99%	<0.01
Counties Power	3.06	3.07	100%	0.02	3.03	99%	-0.03
Eastland Network	1.19	1.20	101%	0.01	1.17	99%	-0.01
Electra	1.90	1.90	100%	<0.01	1.90	100%	<0.01
Electricity Ashburton	0.00	0.00		<0.01	0.00		<0.01
Horizon	0.05	`0.06	102%	<0.01	0.06	104%	<0.01
Mainpower	0.81	0.81	100%	<0.01	0.81	100%	<0.01
Marlborough Lines	5.19	5.19	100%	<0.01	5.13	99%	-0.06
Network Tasman	1.90	1.91	100%	0.01	1.93	102%	0.03
Network Waitaki	-0.01	0.00		0.01	0.00		0.01
Northpower	25.04	25.26	101%	0.21	24.83	99%	-0.22
Orion	2.55	2.50	98%	-0.04	2.54	100%	-0.01
Powerco	15.55	15.52	100%	-0.03	15.57	100%	0.02
Powernet *(incl. The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)*	0.72	0.73	101%	0.01	0.72	100%	<0.01
Scanpower	0.09	0.08	99%	<0.01	0.01	16%	-0.07
The Lines Company	0.26	0.28	108%	0.02	0.24	92%	-0.02
Top Energy	7.05	7.05	100%	<0.01	7.05	100%	<0.01

	Base case (average $M per year)	High demand (average $M per year)	As % of base case	Difference from base case	Low demand (average $M per year)	As % of base case	Difference from base case
Unison *(incl. Centralines)*	4.51	4.51	100%	<0.01	4.18	93%	-0.33
Vector	166.71	166.55	100%	-0.16	166.88	100%	0.17
Waipa Power	0.05	0.05	107%	<0.01	0.04	94%	<0.01
WEL	0.91	0.91	100%	<0.01	0.90	100%	<0.01
Wellington Electricity	5.70	5.71	100%	0.01	5.70	100%	<0.01
Westpower	6.19	6.24	101%	0.05	6.16	99%	-0.04
Generators							
Contact	19.02	**19.86**	**104%**	**0.84**	**17.49**	**92%**	**-1.54**
Genesis	4.02	3.89	97%	-0.12	4.06	101%	0.05
Meridian	9.20	8.92	97%	-0.28	9.47	103%	0.27
Mokai JV	0.11	0.11	94%	-0.01	0.11	100%	<0.01
MRP	3.52	3.51	100%	-0.01	3.54	101%	0.02
NAP JV	1.07	1.02	95%	-0.05	1.06	99%	-0.01
Ngatamariki	0.55	0.52	95%	-0.03	0.54	99%	-0.01
Pioneer	0.24	0.24	100%	<0.01	0.24	99%	<0.01
Todd	0.56	0.53	95%	-0.03	0.56	101%	<0.01
Trustpower	2.00	1.86	93%	-0.14	2.02	101%	0.02
Major consumers							
CHH	0.54	0.58	107%	0.04	0.49	91%	-0.05
Daiken MDF	0.08	0.08	100%	<0.01	0.08	100%	<0.01
Kiwirail	0.00	0.00	83%	<0.01	0.00	95%	<0.01
Methanex	0.09	0.09	92%	-0.01	0.09	99%	<0.01
Norske Skog	0.00	0.00		<0.01	0.00		<0.01

	Base case (average $M per year)	High demand (average $M per year)	As % of base case	Difference from base case	Low demand (average $M per year)	As % of base case	Difference from base case
NZ Steel	0.03	0.03	96%	<0.01	0.03	105%	<0.01
NZAS	1.25	1.25	100%	<0.01	1.24	99%	-0.02
Pacific Steel	0.57	0.58	101%	0.01	0.56	98%	-0.01
PanPac	0.39	0.39	101%	<0.01	0.39	99%	<0.01
Rayonier	0.02	0.02	101%	<0.01	0.02	99%	<0.01
Winstones	0.00	0.00		<0.01	0.00		<0.01

Table 2 shows how these sensitivities affect the modelled allocation of all charges combined (ie, the deeper connection charge, area-of-benefit charge and capacity-based residual charge).

Again, for most parties, there is little difference between the base case and the high and low demand scenarios.

Some exceptions, highlighted in **bold** in the table, are that:

- Aurora is modelled as paying $0.6 million per year more in the low demand scenario than in the base case[8]
- Vector is modelled as paying $0.6 million per year more in the low demand scenario[9]
- Contact is modelled as paying $0.9 million per year more in the high demand scenario, and $1.6 million per year less in the low demand scenario[10]
- Meridian is modelled as paying $0.4 million per year less in the high demand scenario, and $0.5 million per year more in the low demand scenario.[11]

As with Table 1, note that there are some cases where a party pays slightly more in both the low demand scenario and the high demand scenario than in the base case – or the reverse. These cases can be attributed to coincidence – there is no logical reason why there need be a monotone relationship between national demand growth and charges paid by individual parties.

8 Largely because Aurora pays a larger deeper connection charge under the low demand scenario, as set out in the previous table.

9 Largely because the rate of the capacity-based residual charge is lower in the high demand scenario, and higher in the low demand scenario. This, in turn, is because the combined AMD of major consumers is higher in the high demand scenario, and lower in the low demand scenario.

10 Largely as a result of changes in Contact's deeper connection charges, as set out in the previous table.

11 Partly as a result of changes in Meridian's deeper connection charges, as set out in the previous table, and partly because Meridian's generation output – and hence its allocation of the area-of-benefit charge – is higher in the high demand scenario, and lower in the low demand scenario.

Table 2: Comparison of all charges combined, between the base case and the high and low demand scenarios

	Base case (average $M per year)	High demand (average $M per year)	As % of base case	Difference from base case	Low demand (average $M per year)	As % of base case	Difference from base case
EDBs							
Alpine Energy	7.89	7.88	100%	-0.01	7.91	100%	0.02
Aurora Energy	18.71	18.70	100%	-0.01	**19.29**	**103%**	**0.59**
Buller Electricity	1.69	1.69	100%	<0.01	1.68	100%	<0.01
Counties Power	12.51	12.52	100%	0.01	12.51	100%	<0.01
Eastland Network	6.49	6.50	100%	<0.01	6.50	100%	0.01
Electra	10.38	10.37	100%	-0.01	10.41	100%	0.03
Electricity Ashburton	4.83	4.83	100%	-0.01	4.85	100%	0.02
Horizon	5.06	5.06	100%	-0.01	5.08	100%	0.02
Mainpower	8.10	8.09	100%	-0.01	8.12	100%	0.02
Marlborough Lines	10.57	10.57	100%	<0.01	10.54	100%	-0.04
Network Tasman	11.58	11.57	100%	-0.01	11.64	101%	0.06
Network Waitaki	2.80	2.81	100%	0.01	2.82	101%	0.02
Northpower	35.98	36.18	101%	0.20	35.80	99%	-0.18
Orion	42.17	42.08	100%	-0.09	42.29	100%	0.12
Powerco	79.22	79.11	100%	-0.11	79.47	100%	0.24
Powernet *(incl. The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)*	16.10	16.10	100%	-0.01	16.15	100%	0.05
Scanpower	1.44	1.43	100%	<0.01	1.37	95%	-0.07
The Lines Company	4.88	4.90	100%	0.02	4.88	100%	<0.01
Top Energy	13.05	13.04	100%	-0.01	13.07	100%	0.02

	Base case (average $M per year)	High demand (average $M per year)	As % of base case	Difference from base case	Low demand (average $M per year)	As % of base case	Difference from base case
Unison *(incl. Centralines)*	28.54	28.51	100%	-0.03	28.29	99%	-0.25
Vector	285.18	284.88	100%	-0.30	**285.74**	**100%**	**0.56**
Waipa Power	4.96	4.96	100%	<0.01	4.97	100%	0.01
WEL	19.07	19.05	100%	-0.02	19.13	100%	0.06
Wellington Electricity	41.78	41.75	100%	-0.03	41.91	100%	0.13
Westpower	9.08	9.13	101%	0.05	9.05	100%	-0.03
Generators							
Contact	42.40	**43.34**	**102%**	**0.94**	**40.80**	**96%**	**-1.60**
Genesis	7.82	7.68	98%	-0.14	7.88	101%	0.06
Meridian	43.46	**43.02**	**99%**	**-0.44**	**43.97**	**101%**	**0.51**
Mokai JV	0.57	0.54	96%	-0.02	0.58	102%	0.01
MRP	5.05	5.03	100%	-0.02	5.06	100%	0.01
<0.01NAP JV	1.64	1.57	96%	-0.07	1.65	100%	<0.01
Ngatamariki	0.86	0.82	96%	-0.03	0.86	100%	<0.01
Pioneer	0.61	0.61	100%	<0.01	0.61	100%	<0.01
Todd	0.70	0.67	95%	-0.03	0.71	101%	<0.01
Trustpower	4.91	4.91	100%	0.01	4.72	96%	-0.19
Major consumers							
CHH	1.37	1.44	105%	0.07	1.29	94%	-0.08
Daiken MDF	0.19	0.19	102%	<0.01	0.19	98%	<0.01
Kiwirail	0.16	0.17	103%	<0.01	0.16	97%	<0.01
Methanex	0.18	0.18	98%	<0.01	0.18	98%	<0.01
Norske Skog	1.10	1.10	100%	<0.01	1.10	100%	<0.01

	Base case (average $M per year)	High demand (average $M per year)	As % of base case	Difference from base case	Low demand (average $M per year)	As % of base case	Difference from base case
NZ Steel	1.65	1.71	104%	0.06	1.59	97%	-0.06
NZAS	6.86	6.86	100%	-0.01	6.87	100%	<0.01
Pacific Steel	1.24	1.27	102%	0.03	1.21	98%	-0.03
PanPac	1.18	1.22	103%	0.03	1.15	97%	-0.03
Rayonier	0.39	0.40	101%	<0.01	0.39	100%	<0.01
Winstones	0.39	0.40	102%	0.01	0.38	98%	-0.01

Northland and West Coast generation scenarios

Input assumptions

The Northland generation scenario includes an additional 100 MW of embedded geothermal generation at the Kaikohe node. The new plant is assumed to operate as baseload, at 90% of its nameplate capacity, without outages.

The West Coast generation scenario includes an additional 85 MW of grid-connected hydro generation at the Kumara node. The new plant is assumed to be offered similarly to the existing embedded hydro generation at Kumara.

The Authority emphasises that these scenarios are merely illustrative, and are not intended to represent any specific planned or proposed generation projects.

All other input assumptions are the same as in the base case.

Results

Table 3 shows how these sensitivities affect the modelled allocation of deeper connection charges.

For most parties, there is little difference between the base case and the generation scenarios.

For parties that own, or are close to the location of, the new generation, there can be a substantial difference. Some examples, highlighted in **bold** in the table, are that:

- in the Northland generation scenario:
  - Top Energy (assumed to be the owner of the new generating plant) pays $6.8 million per year less than in the base case *(ie 3% of the amount under the base case)*
  - Northpower pays $16.6 million per year less than in the base case
  - Vector pays $24.2 million per year more than in the base case
- in the West Coast generation scenario:
  - Westpower pays $2.7 million per year less than in the base case
  - the owner of the new generation (assumed to be Trustpower for modelling purposes only) pays $1.5 million per year more than in the base case
  - Buller Electricity pays $1.1 million per year more than in the base case
  - Marlborough Lines pays $0.5 million per year more than in the base case
  - Network Tasman pays $1.1 million per year more than in the base case.

There are also changes in charges for some more distant parties. For example, in the Northland generation scenario:

- Genesis pays $1.0 million per year less[12]
- Meridian pays $0.8 million per year less[13]
- Nga Awa Purua geothermal generation pays $0.2 million per year more[14]
- Electra pays $0.2 million per year more[15]
- Waipa pays $0.03 million more (which, while small in absolute terms, is 58% more)[16]

[12] Largely because Genesis pays a lower share of the costs of the Wairakei Ring and the Huntly substation. The former is because Rangipo's flow share through the Ring falls below the 3% cutoff; the latter is because the load HHI of the substation is higher than in the base case.

[13] Largely because Meridian pays a lower share of the costs of several transmission links, including those from Tekapo B to Islington, Haywards to Wilton to Takapu Rd, and Benmore to Ohau B and Ohau C. These changes are largely driven by reductions in Meridian's generation, which is modelled as being displaced by the new generation in Northland.

[14] Largely because Nga Awa Purua pays a higher share of the costs of the Wairakei Ring, which in turn is because Genesis pays a reduced share, for the reason given above.

[15] Because Electra pays an increased share of the costs of the circuits from Wilton to Takapu Rd, which in turn is because Meridian pays a reduced share of the costs of these circuits.

[16] In part, because Waipa pays a higher share of the costs of the Wairakei Ring, which in turn is because Genesis pays a reduced share, for the reason given above.

- WEL Networks pays $0.14 million per year more[17]
- Wellington Electricity pays $0.4 million per year more.[18]

Similarly, in the West Coast generation scenario:

- Scanpower pays $0.07 million less (which, while small in absolute terms, is 84% less)[19]
- Unison pays $0.4 million per year less.[20]

In conclusion:

- the addition of a large amount of new generation in Northland is modelled as shifting charges from Top Energy and Northpower to Vector *(because it leads to Vector paying a larger share of the costs of the North Auckland and Northland (NAaN) and North Island grid upgrade (NIGU) projects)*
- the addition of a large amount of new generation in the Westpower area is modelled as shifting charges from Westpower to Buller and the owner of the new generation *(in large part this reflects the allocation of the costs of the Dobson-Reefton upgrade)*. This change also increases charges on other Upper South Island distributors, resulting in a net increase in the total amount recovered through the deeper connection charge
- there are some 'knock-on' effects on other parties.

Parties should take note that these conclusions may be sensitive to the amount of generation added, the way in which it is assumed to operate, the location and the owner.

[17] Largely because WEL pays a higher share of the costs of the Wairakei Ring and the Whakamaru substation.

[18] Largely because WE pays an increased share of the costs of the circuits from Wilton to Takapu Rd, which in turn is because Meridian pays a reduced share of the costs of these circuits.

[19] Largely because the generation HHI of assets at and around Dannevirke increases, which in turn is largely driven by changes in generation in the area, which is modelled as being displaced by the new generation in the South Island.

[20] For similar reasons to Scanpower above.

Table 3: Comparison of deeper connection charges on pre-2017 assets, between the base case and the Northland and West Coast generation scenarios

	Base case (average $M per year)	Northland generation (average $M per year)	As % of base case	Difference from base case	WCSI generation (average $M per year)	As % of base case	Difference from base case
EDBs							
Alpine Energy	0.79	0.79	100%	<0.01	0.79	100%	<0.01
Aurora Energy	0.49	0.50	102%	0.01	0.49	100%	<0.01
Buller Electricity	0.73	0.72	99%	-0.01	**1.82**	**248%**	**1.09**
Counties Power	3.06	3.13	102%	0.07	3.06	100%	<0.01
Eastland Network	1.19	1.18	100%	<0.01	1.19	100%	<0.01
Electra	1.90	**2.10**	**111%**	**0.20**	1.91	100%	0.01
Electricity Ashburton	0.00	0.00		<0.01	0.00		<0.01
Horizon	0.05	0.05	100%	<0.01	0.05	100%	<0.01
Mainpower	0.81	0.81	100%	<0.01	0.82	101%	0.01
Marlborough Lines	5.19	5.16	100%	-0.02	**5.69**	**110%**	**0.50**
Network Tasman	1.90	1.85	97%	-0.05	**3.05**	**160%**	**1.14**
Network Waitaki	-0.01	0.00		0.01	0.00		0.01
Northpower	25.04	**8.46**	**34%**	**-16.58**	25.04	100%	<0.01
Orion	2.55	2.54	100%	-0.01	2.58	101%	0.03
Powerco	15.55	15.61	100%	0.06	15.55	100%	<0.01
Powernet *(incl. The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)*	0.72	0.73	101%	<0.01	0.72	100%	<0.01
Scanpower	0.09	0.09	100%	<0.01	**0.01**	**16%**	**-0.07**
The Lines Company	0.26	0.21	81%	-0.05	0.28	108%	0.02
Top Energy	**7.05**	**0.21**	**3%**	**-6.84**	7.04	100%	<0.01

	Base case (average $M per year)	Northland generation (average $M per year)	As % of base case	Difference from base case	WCSI generation (average $M per year)	As % of base case	Difference from base case
Unison *(incl. Centralines)*	4.51	4.51	100%	<0.01	**4.15**	**92%**	**-0.36**
Vector	166.71	**190.87**	**114%**	**24.16**	166.70	100%	-0.01
Waipa Power	0.05	**0.07**	**158%**	**0.03**	0.05	100%	<0.01
WEL	0.91	**1.05**	**116%**	**0.14**	0.91	100%	<0.01
Wellington Electricity	5.70	**6.13**	**108%**	**0.43**	5.69	100%	-0.01
Westpower	6.19	6.16	99%	-0.03	**3.47**	**56%**	**-2.72**
Generators							
Contact	19.02	19.23	101%	0.21	18.98	100%	-0.05
Genesis	4.02	**3.02**	**75%**	**-1.00**	4.02	100%	<0.01
Meridian	9.20	**8.35**	**91%**	**-0.85**	9.43	102%	0.23
Mokai JV	0.11	0.13	111%	0.01	0.11	98%	<0.01
MRP	3.52	3.64	104%	0.13	3.49	99%	-0.02
NAP JV	1.07	**1.27**	**119%**	**0.21**	1.05	99%	-0.02
Ngatamariki	0.55	0.65	119%	0.10	0.54	99%	-0.01
Pioneer	0.24	0.24	99%	<0.01	0.24	100%	<0.01
Todd	0.56	0.49	88%	-0.07	0.55	99%	<0.01
Trustpower	2.00	1.90	95%	-0.10	**3.54**	**177%**	**1.54**
Major consumers							
CHH	0.54	0.62	114%	0.08	0.55	102%	0.01
Daiken MDF	0.08	0.08	100%	<0.01	0.08	101%	<0.01
Kiwirail	0.00	0.00	126%	<0.01	0.00	100%	<0.01
Methanex	0.09	0.09	98%	<0.01	0.09	100%	<0.01
Norske Skog	0.00	0.00		<0.01	0.00		<0.01
NZ Steel	0.03	0.06	219%	0.03	0.03	100%	<0.01
NZAS	1.25	1.27	101%	0.02	1.26	100%	<0.01

	Base case (average $M per year)	Northland generation (average $M per year)	As % of base case	Difference from base case	WCSI generation (average $M per year)	As % of base case	Difference from base case
Pacific Steel	0.57	0.61	107%	0.04	0.57	100%	<0.01
PanPac	0.39	0.39	100%	<0.01	0.39	100%	<0.01
Rayonier	0.02	0.02	101%	<0.01	0.02	100%	<0.01
Winstones	0.00	0.00		<0.01	0.00		<0.01