Electricity distribution business pricing reform

Analysis of Electricity Networks Association pricing review and proposed changes

NZIER report to MEUG

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Key points

EDB approaches to fixed charges vary widely in terms of both the type of fixed charge (daily/ monthly, maximum demand or maximum capacity) and the proportion of revenue earned through fixed charges. This means that EDB potential exposure to a change in revenue due to a change in energy supplied to residential customers also varies widely. This variation appears to have existed for some time, which suggests EDB are not converging to a single ‘preferred or ideal’ pricing structure.

Solar PV installation is gradually replacing electricity supplied by EDB for some customers but at the moment the growth rate is linear rather than exponential. Unregulated and to a lesser extent small to medium sized regulated EDB are much more exposed to reduced demand for electricity supply due to solar PV growth than large regulated EDB.

Our sample of EDB pricing methodologies indicates that the most common method of allocating transmission costs is based on contribution to RCPD (for customers for whom this can be measured) and contribution to anytime maximum demand for mass market customers (if contribution to RCPD cannot be measured or the EDB has summer and winter peaks attributable to different customer groups).

The proposal to abolish RCPD based allocation of transmission costs and implement a combination of area of benefit charge and residual charge allocated on historical network use is likely to be replicated in EDB pricing.

The ENA pricing option summary table describes the main types of pricing option available to EDB and includes criteria that cover both achieving the objective of efficient pricing and considering stakeholder attitudes. The next steps in improving the assessment of the components could be:

- recognising that EDB are likely to use bundles of the components for the same group of customers rather than one component
- cross-checking the assessment of the components against current EDB pricing plans, recent experience of rationalising pricing plans and stated intentions for change
- describing the case for change for types of EDB.

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1. EDB pricing information

1.1. Introduction

This section includes:

- number of interconnection points (ICP) and the volumes of energy used grouped according to the type of fixed charge[1] applied by electricity distribution business (EDB) for the year ended 31 March 2016[2]
- number of ICP, capacity and estimated generation for residential solar photo voltaic (PV) for 2016 and estimated shares of EDB.

1.2. Pricing plans

The analysis in this section is based on data provided by EDB in section 8 of their information disclosures to the Commerce Commission. For each reported pricing plan, these information disclosures list the number of ICPs, energy supplied and revenue earned. The revenue earned is decomposed by pricing component.[3] For this report we have grouped the pricing components as follows:

- per kWh of energy supplied
- 'fixed time' – a charge per day, month, year or any other set unit of time
- 'fixed demand' – a charge per kW per unit of time
- 'fixed capacity KVA' – a charge per kVA per unit of time
- 'fixed capacity KVAr' – a charge per kVAr per unit of time
- 'fixed other' – which includes charges for transformers fittings etc. per unit of time.

A starting point for the review of EDB pricing is consideration of how well-suited the fixed charging component of price plans is to recovering the cost of the network from customers based on the service they demand from the network.

EDB pricing plans are generally based on a fixed daily charge plus a charge for energy used. However, some EDB do base their fixed charge on maximum demand or agreed capacity (so that they vary by customer) rather than a fixed daily charge. The bulk of EDB revenue continues to be earned from charges based on energy consumed.

The following tables show the number of ICP and energy usage by fixed charge type separately for EDB subject to Commerce Commission price path control (regulated) and for EDB subject to Commerce Commission information disclosure requirements (unregulated). The EDB are sorted by descending order of total revenue (for the tables on both all customers and residential customers).

1 The next version of this report will include information on time of use and controllable load plans for the EDB listed as of interest to MEUG,

2 Source: EDB information disclosures to the Commerce Commission.

3 For some EDB some of these components are negative indicating discounts or rebates in the pricing plans. For this analysis we have used the data as reported and not adjusted for differences in how discounts and rebates are reported by EDB.

Some EDB have both daily and other fixed charges for customers on the same plan. In this case the total of the cells in each row will exceed the total for that EDB shown in the last column.

Our analysis of the basis for setting fixed charges indicates that:

- for residential consumers:
  - fixed charges are set as a time based rate – no discrimination within the pricing plan on the basis of service demanded for most customers
  - only two of the regulated EDB (Orion and Nelson Electricity) set their fixed charges solely on the basis of capacity
  - four of the regulated EDB (Powerco, Aurora Energy, Network Tasman, The Lines Company and Otago Net Joint Venture) set their fixed charges as a combination of daily and capacity charges for their customers[4]
  - all of the unregulated EDB set their fixed charges as a time based rate – no discrimination within the pricing plan on the basis of service demanded for most customers
- for commercial customers:
  - fixed charges by ICP are generally based on a combination of time based charges and components that reflect demand placed on the network such as capacity, maximum demand or other charges
  - fixed charges by energy supply are more likely to include a demand or capacity component than the fixed
  - nearly all of the unregulated EDB (except Westpower) have fixed charges based on time. Less than half have any form of fixed charge based on demand or capacity and these charges only apply to some of the ICPs and part of the energy supplied.

This suggests the following relevant issues for the EDB pricing review:

- for regulated EDB:
  - there is a wide variety of approaches to setting fixed charges (which amplifies the variation in regulated EDB pricing created by different tariff structures for energy supplied as well as differing levels of reliance on fixed and energy supplied charges
  - the variation does not appear to be correlated with either EDB size or mix of customers
- for unregulated EDB:
  - there seems to be little use of fixed charges based on demand or capacity along with heavy reliance on charges for energy supplied.

[4] For most of these EDB (Powerco, Network Tasman, The Lines Company, and Otago Net Joint Venture) it appears that the fixed charges for all residential customers are a combination of daily and capacity charges. For Aurora Energy, it appears that all customers are an affixed daily charge but one group also faces a capacity charge.

Table 1 Residential ICP by fixed charge type (regulated)

Number of ICP for plans where average energy used per ICP is between 1 and 15 kWh per year

EDB	Fixed Time (daily/ monthly)	Fixed Demand	Fixed Capacity KVA	Fixed Capacity KVAr	Other	Total[1]
Vector	479,512	0	0	0	0	479,515
Powerco	328,634	501	328,134	0	0	328,634
Orion NZ	0	0	190,718	0	0	190,718
Wellington Electricity	149,383	0	0	0	0	149,383
Unison Networks	102,585	0	0	0	0	102,958
Aurora Energy	78,167	0	13,744	0	0	78,167
Alpine Energy	28,942	0	0	0	0	28,942
EA Networks	14,685	0	0	0	0	14,685
Top Energy	30,826	0	0	0	0	30,826
Network Tasman	35,539	0	35,511	0	0	35,540
The Lines Company[2]	21,135	21,135	21,135	0	0	21,135
Otago Net Joint Venture	4,905	0	6,876	0	0	11,781
Eastland Network	24,903	0	0	0	0	24,903
Horizon Energy Distribution	22,988	0	0	0	0	22,988
Electricity Invercargill	15,224	0	0	0	0	15,224
Centralines	7,602	0	0	0	0	7,745
Nelson Electricity	0	0	9,062	0	0	9,062

Note:

1. Some EDB have both daily and other fixed charges for customers on the same plan. In this case the total of the cells in each row will exceed the total for that EDB shown in the last column. This applies to Powerco, Aurora Energy, Network Tasman and Otago Net Joint Venture.

Source: NZIER analysis of EDB information disclosures to the Commerce Commission

Table 2 Residential energy used by fixed charge type (regulated)

Energy used in MWh for plans where average energy used per ICP is between 1 and 15 kWh per year

EDB	Fixed Time (daily/ monthly)	Fixed Demand	Fixed Capacity KVA	Fixed Capacity KVAr	Other	Total[1]
Vector	3,366	0	0	0	0	3,366
Powerco	2,604	3	2,601	0	0	2,604
Orion NZ	0	0	2,346	0	0	2,346
Wellington Electricity	1,061	0	0	0	0	1,061
Unison Networks	712	0	0	0	0	713
Aurora Energy	616	0	87	0	0	616
Alpine Energy	297	0	0	0	0	297
EA Networks	124	0	0	0	0	124
Top Energy	203	0	0	0	0	203
Network Tasman	238	0	238	0	0	238
The Lines Company	185	185	185	0	0	185
Otago Net Joint Venture	23	0	52	0	0	76
Eastland Network	161	0	0	0	0	161
Horizon Energy Distribution	154	0	0	0	0	154
Electricity Invercargill	135	0	0	0	0	135
Centralines	42	0	0	0	0	42
Nelson Electricity	0	0	82	0	0	82

Note:

1. Some EDB have both daily and other fixed charges for customers on the same plan. In this case the total of the cells in each row will exceed the total for that EDB shown in the last column. This applies to Powerco, Aurora Energy, Network Tasman and Otago Net Joint Venture.

Source: NZIER analysis of EDB information disclosures to the Commerce Commission

Table 3 Non-residential ICP by fixed charge type (regulated)

Number of ICP for plans where average energy used per ICP above 15 kWh per year

EDB	Fixed Time (daily/ monthly)	Fixed Demand	Fixed Capacity KVA	Fixed Capacity KVAr	Other	Total[1]
Vector	64,008	0	6,089	6,125	0	66,452
Powerco	1,678	0	1,873	1,943	0	1,943
Orion NZ	400	0	411	0	800	411
Wellington Electricity	17,207	38	1,016	38	0	17,207
Unison Networks	8,030	7,978	0	8,029	0	8,088
Aurora Energy	6,498	6,470	6,950	0	0	6,487
Alpine Energy	2,948	1,752	0	0	0	2,948
EA Networks	2,473	1,567	47	0	0	4,042
Top Energy	199	0	0	0	0	199
Network Tasman	0	2,850	147	136	3	2,906
The Lines Company	2,517	2,474	2,515	0	0	2,516
Otago Net Joint Venture	305	204	3,354	0	0	3,659
Eastland Network	504	0	0	0	0	504
Horizon Energy Distribution	1,505	148	204	0	0	1,709
Electricity Invercargill	2,148	0	0	0	0	2,148
Centralines	721	103	0	103	0	721
Nelson Electricity	147	0	185	0	0	145

Note:

1. Some EDB have both daily and other fixed charges for customers on the same plan. In this case the total of the cells in each row will exceed the total for that EDB shown in the last column.

Source: NZIER analysis of EDB information disclosures to the Commerce Commission

Table 4 Non-residential energy use by fixed charge type (regulated)

Energy use in MWh for plans where average energy used per ICP is above 15 kWh per year

EDB	Fixed Time (daily/ monthly)	Fixed Demand	Fixed Capacity KVA	Fixed Capacity KVAr	Other	Total[1]
Vector	2,944	0	3,123	3,838	0	5,063
Powerco	1,391	0	1,315	1,926	0	1,926
Orion NZ	714	0	808	0	1,427	808
Wellington Electricity	1,292	176	1,185	176	0	1,292
Unison Networks	859	628	0	859	0	873
Aurora Energy	642	616	979	0	0	632
Alpine Energy	513	479	0	0	0	993
EA Networks	233	244	102	0	0	479
Top Energy	111	0	0	0	0	111
Network Tasman	0	238	140	107	118	366
The Lines Company	185	39	168	0	0	184
Otago Net Joint Venture	298	6	59	0	0	356
Eastland Network	119	0	0	0	0	119
Horizon Energy Distribution	321	48	52	0	0	373
Electricity Invercargill	131	0	0	0	0	131
Centralines	64	47	0	47	0	64
Nelson Electricity	58	0	58	0	0	58

Note:

1. Some EDB have both daily and other fixed charges for customers on the same plan. In this case the total of the cells in each row will exceed the total for that EDB shown in the last column.

Source: NZIER analysis of EDB information disclosures to the Commerce Commission

Table 5 Residential ICP by fixed charge type (unregulated)

Number of ICP for plans where average energy used per ICP is between 1 and 15 kWh per year

EDB	Fixed Time (daily/ monthly)	Fixed Demand	Fixed Capacity KVA	Fixed Capacity KVAr	Other	Total
MainPower NZ	32,527	0	0	0	0	32,527
WEL Networks	74,777	0	0	0	0	74,777
Northpower	57,165	0	0	0	0	57,165
The Power Company	25,939	0	0	0	0	25,939
Counties Power	38,659	0	0	0	0	39,441
Electra	43,331	0	0	0	0	43,331
Marlborough Lines	21,142	0	0	0	0	21,142
Waipa Networks	19,672	0	0	0	0	19,672
Westpower	12,525	0	0	0	0	12,525
Network Waitaki	11,276	0	0	0	0	11,276
Scanpower	4,722	0	0	0	0	4,722
Buller Electricity	3,969	0	0	0	0	3,969

Source: NZIER analysis of EDB information disclosures to the Commerce Commission

Table 6 Residential energy use by fixed charge type (unregulated)

Energy used in MWh for plans where average energy used per ICP is between 1 and 15 kWh per year

EDB	Fixed Time (daily/ monthly)	Fixed Demand	Fixed Capacity KVA	Fixed Capacity KVAr	Other	Total
MainPower NZ	259	0	0	0	0	260
WEL Networks	506	0	0	0	0	506
Northpower	453	0	0	0	0	453
The Power Company	218	0	0	0	0	218
Counties Power	352	0	0	0	0	352
Electra	295	0	0	0	0	295
Marlborough Lines	146	0	0	0	0	146
Waipa Networks	155	0	0	0	0	155
Westpower	80	0	0	0	0	80
Network Waitaki	80	0	0	0	0	80
Scanpower	58	0	0	0	0	58
Buller Electricity	20	0	0	0	0	20

Source: NZIER analysis of EDB information disclosures to the Commerce Commission

Table 7 Non-residential ICP by fixed charge type (unregulated)

Number of ICP for plans where average energy used per ICP is above 15 kWh per year

EDB	Fixed Time (daily/ monthly)	Fixed Demand	Fixed Capacity KVA	Fixed Capacity KVAr	Other	Total[1]
MainPower NZ	6,565	0	0	0	0	6,730
WEL Networks	12,926	12,865	0	12,863	60	12,926
Northpower	82	6	76	0	0	82
The Power Company	9,535	0	0	0	0	9,535
Counties Power	124	0	314	0	0	306
Electra	876	0	0	0	0	876
Marlborough Lines	3,729	0	0	0	0	3,729
Waipa Networks	5,252	0	29	0	4	5,277
Westpower	0	878	44	0	0	878
Network Waitaki	1,364	0	0	0	0	1,364
Scanpower	0	0	38	0	0	27
Buller Electricity	620	16	540	0	0	636

Note:

1. Some EDB have both daily and other fixed charges for customers on the same plan. In this case the total of the cells in each row will exceed the total for that EDB shown in the last column.

Source: NZIER analysis of EDB information disclosures to the Commerce Commission

Table 8 Non-residential energy use by fixed charge type (unregulated)

Energy used in MWh for plans where average energy used per ICP is above 15 kWh per year

EDB	Fixed Time (daily/ monthly)	Fixed Demand	Fixed Capacity KVA	Fixed Capacity KVAr	Other	Total[1]
MainPower NZ	370	0	0	0	0	373
WEL Networks	719	706	0	689	10	719
Northpower	576	491	85	0	0	576
The Power Company	491	0	0	0	0	491
Counties Power	9	0	220	0	0	202
Electra	114	0	0	0	0	114
Marlborough Lines	231	0	0	0	0	231
Waipa Networks	195	0	38	0	14	218
Westpower	0	185	129	0	0	185
Network Waitaki	181	0	0	0	0	181
Scanpower	0	0	35	0	0	19
Buller Electricity	14	19	9	0	0	33

Note:

1. Some EDB have both daily and other fixed charges for customers on the same plan. In this case the total of the cells in each row will exceed the total for that EDB shown in the last column.

Source: NZIER analysis of EDB information disclosures to the Commerce Commission

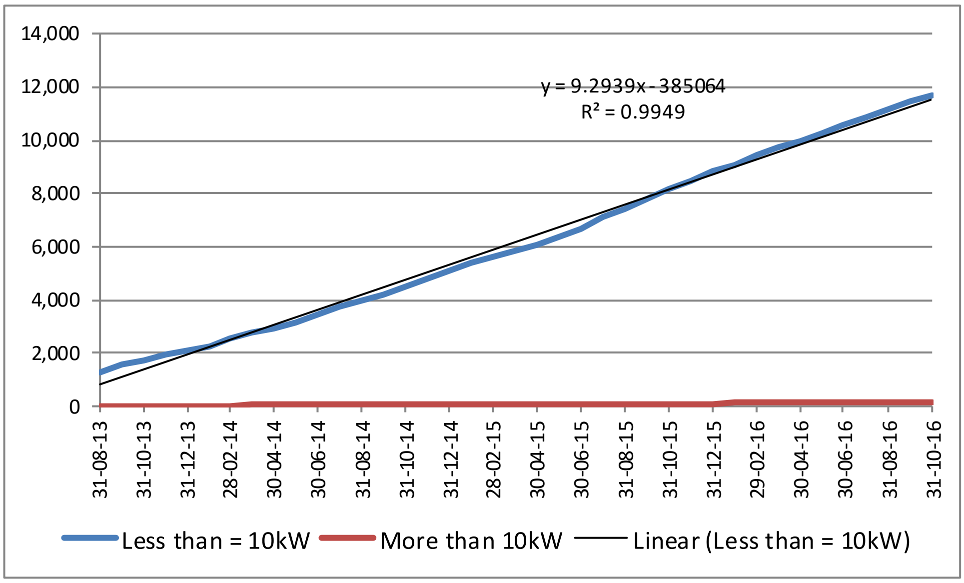
1.3. Solar PV and battery

The number of ICP with solar PV is approximately 0.5 percent of the number of residential ICP (across New Zealand) and is estimated to generate 0.2 percent of the energy used (across New Zealand). (The average capacity of residential solar PV installations is 3.5 kW per ICP.)

Residential solar PV installation seems to be following a linear rather than an exponential growth path over the past three years. On average about 270 residential ICP systems are installed across the country each month adding about 1 MW of capacity each month or 12 MW of capacity per year. Commercial installation of solar PV is also increasing but at a much slower rate than residential installation. The average capacity of commercial solar PV installations is 33 kW per ICP. The following charts show the number of ICP with solar PV and total installed capacity.

Figure 1 Solar PV installations residential and commercial

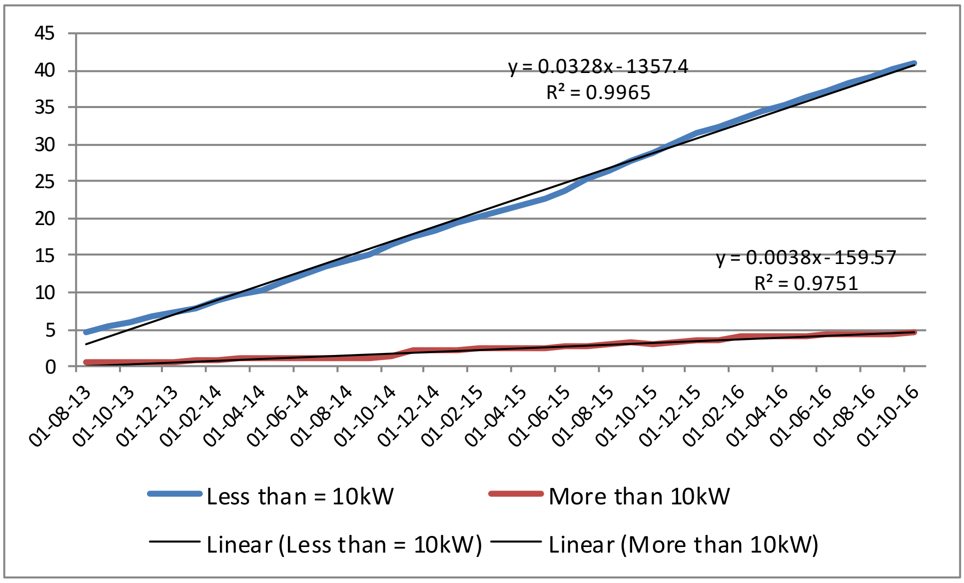
Total number of ICP with solar PV over the period 31 August 2013 to 31 October 2016



Source: NZIER analysis of Electricity Authority data on generation

Figure 2 Solar PV capacity residential and commercial

Total solar PV capacity over the period 31 August 2013 to 31 October 2016



Source: NZIER analysis of Electricity Authority data on generation

The Electricity Demand and Generation Scenarios EDGS 2016[5] forecast solar PV capacity to grow by an average of 20 MW per year over the next five years. The EDGS

5 Source: 'Electricity Demand and Generation Scenarios 2016', Mixed Renewables, Ministry of Business, Innovation, and Employment. (The EDGS estimate of capacity for 2016 is 57 MW compared to a maximum of 46 MW for the EA data.) available at http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/edgs-2016/?searchterm=EDGS%2A.

2016 and extrapolation of the trend in installation suggest the following range for the growth in solar PV generation over the next five years:

- low-side estimate (extrapolation of trend) – capacity installed reaches about 105 MW in 2021 and generates about 0.9 percent of residential demand[6]
- high-side estimate (EDGS growth in capacity[7]) –installed capacity reaches about 169 MW in 2021 and generates about 1.2 to 1.4 percent of residential demand[8].

1.4. Variation across EDB

The main effect of increased solar PV on EDB revenue is from the reduction in revenue from charges linked to ICP consumption of electricity. EDB exposure to this reduction in revenue is a combination of both EDB reliance on consumption based charging and the increase in solar PV generation in their area. The following tables list the estimated generation from residential solar PV as a percentage of the share of the energy supplied to residential consumers.

We have multiplied the estimated percentage of 'energy supplied from solar PV' by the percentage of residential revenue from per kWh charges and used this an indicator of EDB exposure to reduced income from installation of solar PV. For illustrative purposes, we have highlighted EDB where this indicator is above 0.4 percent.

6 Estimated as 1.35GWh/MW of capacity based on estimated generation from the website http://pvwatts.nrel.gov/pvwatts.php.

7 See: 'Electricity Demand and Generation Scenarios 2016, Mixed Renewables, Installed capacity'

8 The high-side estimate (EDGS growth in capacity) for solar PV generation per unit of capacity vary over the forecast period but for the period 2019 to 2023 seem to average between 1.15 and 1.25 GWh/MW of capacity or about 8 to 15 percent below the estimated generation used for the 'low side estimate (extrapolation of trend)'.

Table 9 Residential solar PV – estimated generation (regulated)

Estimated generation as a percentage of energy supplied and percentage of revenue from energy supplied

EDB	Solar PV generation as a percentage of energy supplied[1]				Per kWh revenue as a percentage of total revenue
	2014	2015	2016	31 Oct 2016[2]	
Vector	0.08%	0.22%	0.31%	0.33%	73%
Powerco	0.07%	0.12%	0.23%	0.30%	64%
Orion NZ	0.05%	0.14%	0.23%	0.29%	54%
Wellington Electricity	0.04%	0.09%	0.14%	0.16%	74%
Unison Networks	0.09%	0.26%	0.42%	0.45%	69%
Aurora Energy	0.11%	0.27%	0.41%	0.48%	83%
Alpine Energy	0.11%	0.22%	0.38%	0.33%	69%
EA Networks	0.29%	0.43%	0.51%	0.52%	91%
Top Energy	0.19%	0.34%	0.63%	0.92%	98%
Network Tasman	0.44%	0.72%	0.99%	1.12%	91%
The Lines Company	0.06%	0.07%	0.07%	0.07%	0%
Otago Net Joint Venture	#DIV/0!	0.35%	0.55%	0.59%	68%
Eastland Network	0.05%	0.15%	0.32%	0.40%	79%
Horizon Energy Distribution	0.13%	0.18%	0.24%	0.28%	52%
Electricity Invercargill	0.03%	0.12%	0.16%	0.17%	72%
Centralines	0.15%	0.41%	0.68%	0.80%	65%
Nelson Electricity	0.29%	0.33%	0.44%	0.46%	61%

Note:

1. As at 31 March for the years 2014, 2015 and 2016
2. For 31 Oct 2016, estimated solar pv generation based on installations as 31 October 2016, is stated as a percentage of energy supplied over the year to 31 March 2016. This will slightly overstate the share of solar pv.

Source: NZIER

Table 10 Residential solar PV – estimated generation (unregulated)

Estimated generation as a percentage of energy supplied and percentage of revenue from energy supplied

EDB	Solar PV generation as a percentage of energy supplied[1]				Per kWh revenue as a percentage of total revenue
	2014	2015	2016	Oct 2016[2]	
MainPower NZ	0.21%	0.51%	0.34%	0.85%	92%
WEL Networks	0.07%	0.24%	0.42%	0.47%	99%
Northpower	0.08%	0.16%	0.35%	0.50%	88%
The Power Company	0.09%	0.30%	0.41%	0.43%	66%
Counties Power	0.07%	0.16%	0.46%	0.55%	81%
Electra	0.05%	0.11%	0.30%	0.30%	93%
Marlborough Lines	0.20%	0.46%	0.69%	0.79%	64%
Waipa Networks	0.14%	0.25%	0.44%	0.50%	91%
Westpower	0.02%	0.02%	0.05%	0.07%	94%
Network Waitaki	0.12%	0.14%	0.22%	0.27%	86%
Scanpower[3]	0.02%	0.04%	0.05%	0.18%	96%
Buller Electricity	0.12%	0.27%	0.30%	0.33%	74%

Note:

1. As at 31 March for the years 2014, 2015 and 2016
2. For 31 Oct 2016, estimated solar pv generation based on installations as 31 October 2016, is stated as a percentage of energy supplied over the year to 31 March 2016. This will slightly overstate the share of solar pv.
3. Estimated Scanpower solar pv generation is an outlier, possibly due to data error.

Source: NZIER

1.5. Conclusion

The wide variation in EDB approach to fixed charges means that their potential exposure to a change in revenue due to a change in energy supplied to residential customers also varies widely. This variation appears to have existed for some time, which suggests EDB are not converging to a single 'preferred or ideal' pricing structure.

Growth in solar PV installation is gradually replacing electricity supplied by EDB but the extent to which this has been offset by other growth factors is unclear. The statistics on solar PV installations suggest that unregulated and to a lesser extent small to medium sized regulated EDB are much more exposed to reduced demand for electricity supply due to solar PV growth than large regulated EDB.

2. TPM pass-through

2.1. Introduction

The purpose of this section is to assess the readily available data on the pass-through of Transpower charges to residential, commercial and industrial customers and to identify areas where additional analysis is required. For this section we have used the data obtained from the information disclosure and cross-checked this with Transpower data on interconnection charges. We have also reviewed the pricing methodology reports for Vector and Orion.

Three of the regulated EDB and seven (most) of the unregulated EDB do not report payments to Transpower by price plan. The Transpower data for payments by EDB does not reconcile with the Commerce Commission information disclosure data. Some of the gaps are due to differences in the codes used for EDB.

2.2. EDB cost allocation

2.2.1. EDB pricing methodology reports

We have reviewed a sample of the EDB pricing methodology reports. These reports describe the methodology used to allocate costs and list the costs and customer groups to which they are allocated. The allocation of distribution cost seems to be guided by the common principle of recovering the costs of sub-transmission assets and the high and low voltage networks that use the assets. The pass-through of transmission costs varies by EDB but a sample of the approaches is:

- Vector: allocation based on contribution to RCPD
- Powerco: allocation based on contribution of each load group to RCPD divide by number of ICPs in each group
- Orion: allocation based on diversity maximum demand for summer peaks plus an additional allocation for users that only contribute to winter peaks
- Wellington Electricity: customer’s share of monthly GXP volume. (Monthly Customer Volume / Monthly GXP Volume * Monthly GXP Connection Charge)
- Unison: customer contribution to RCPD (as measured or estimated)
- Aurora: customer contribution to RCPD (Aurora is considering the possibility of moving to a capacity charge to spread the recovery of this coats to users with summer peaks.)
- Network Tasman: contribution to RCPD
- Otago Net Joint Venture: contribution to RCPD for customers with time of use metering and for customers without time of use metering an average of contribution to after diversity maximum demand at peak, shoulder and low usage periods
- Horizon Energy: share of anytime maximum demand

- Nelson Electricity: contribution to RCPD (recovered through the energy supplied charge for residential consumers and a mixture of a ‘winter control’ period charge and an energy supplied charge for larger users
- MainPower; allocated across pricing plans by share of consumption
- WEL Network; share of coincident peak demand
- NorthPower;
  - Very large industrial – contribution to RCPD
  - Commercial and industrial – weighted average of anytime maximum demand and shoulder demand
  - Mass market – recovered through energy supplied charges. The difference between transmission components for controlled and uncontrolled loads reflects the impact of regional demand peaks
- The Power Company; after diversity maximum demand during periods of peak network demand adjusted for the duration of the peak for each customer
- Counties Power; contribution to RCPD

2.2.2. Transmission payments and EDB revenue

The following tables compare the share of EDB transmission cost payments recovered from residential customers with the share of EDB revenue from residential customers and the share of energy supplied to residential customers. These tables are an initial attempt to assess whether the recovery of transmission costs is proportional to either EDB revenue from residential customers or the energy supplied. Our naïve hypothesis was that:

- the diversity of pricing methodologies would make the shares of transmission costs from residential customers more widely dispersed across EDB than the share of EDB revenue earned from residential customers
- the recovery of EDB low voltage asset cost as well as some high voltage asset costs from residential would make the share of EDB revenue from residential customers higher than the share of transmission costs recovered from residential customers.

Table 11 Residential share of transmission revenue (regulated)

Share of transmission revenue for residential customers compared to share of revenue and energy supplied

EDB	Share of payment to Transpower	Share of EDB Revenue	Share of total energy supplied
Vector	52.9%	53.8%	39.9%
Powerco	68.1%	76.2%	57.5%
Orion NZ	79.3%	81.7%	74.4%
Wellington Electricity	NA	NA	NA
Unison Networks	NA	NA	NA
Aurora Energy	59.6%	62.0%	49.3%
Alpine Energy	24.5%	40.6%	36.6%
EA Networks	27.1%	22.5%	20.6%
Top Energy	79.8%	81.1%	62.7%
Network Tasman	43.9%	50.7%	39.4%
The Lines Company	67.2%	65.0%	50.2%
Otago Net Joint Venture	22.7%	41.7%	17.6%
Eastland Network	74.6%	77.2%	57.5%
Horizon Energy Distribution	42.5%	59.5%	29.2%
Electricity Invercargill	53.1%	58.9%	50.7%
Centralines	NA	NA	NA
Nelson Electricity	62.1%	71.1%	58.5%

Source: NZIER

Table 12 Residential share of transmission revenue (unregulated)

Share of transmission revenue for residential customers compared to share of revenue and energy supplied

EDB	Share of Transpower	Share of EDB Revenue	Share of total energy supplied
MainPower NZ	45.6%	46.7%	41.1%
WEL Networks	NA	NA	NA
Northpower	NA	NA	NA
The Power Company	30.6%	42.0%	30.8%
Counties Power	NA	NA	NA
Electra	81.8%	81.9%	72.1%
Marlborough Lines	NA	NA	NA
Waipa Networks	NA	NA	NA
Westpower	31.3%	46.6%	30.3%
Network Waitaki	37.3%	42.6%	30.7%
Scanpower	NA	NA	NA
Buller Electricity	NA	NA	NA

Source: NZIER

2.2.3. Estimates of transmission cost

The following tables compare alternative sources of data on transmission costs.

Table 13 Transpower charges paid by EDB (regulated)

Comparison of Transpower and Commerce Commission data for 2015 and 2016

EDB	2015	2015		2016	2016	
	Transpower	Commerce Commission	Difference	Transpower	Commerce Commission	Difference
Vector	188.0	217.5	15.7%	186.0	208.9	12.3%
Powerco	94.0	NA		94.6	115.5	22.1%
Orion NZ	74.5	81.1	8.8%	67.7	78.7	16.1%
Wellington Electricity	65.8	NA		61.5	NA	
Unison Networks	33.4	NA		31.6	NA	
Aurora Energy	24.8	30.5	22.9%	23.9	30.5	27.7%
Alpine Energy	14.0	19.0	35.8%	14.0	15.1	7.9%
EA Networks	5.6	NA		4.6	7.8	
Top Energy	5.9	0.0		5.2	12.6	
Network Tasman	17.7	14.6	-17.7%	11.7	14.6	25.3%
The Lines Company	5.5	7.2	31.8%	5.5	7.4	35.2%
Otago Net Joint Venture	6.6	9.0	35.1%	6.1	8.0	31.7%
Eastland Network	9.1	9.6	6.0%	5.5	9.0	64.7%
Horizon Energy Distribution	6.1	11.0	79.6%	6.6	9.2	39.0%
Electricity Invercargill	0.2	6.2		0.3	6.0	
Centralines	2.8	NA		2.8	NA	
Nelson Electricity	0.0	NA	15.7%	1.1	3.5	12.3%

Source: NZIER

Table 14 Transpower charges paid by EDB (unregulated)

Comparison of Transpower and Commerce Commission data for 2015 and 2016

EDB	2015	2015		2016	2016	
	Transpower	Commerce Commission	Difference	Transpower	Commerce Commission	Difference
MainPower NZ	12.8	12.9	1.1%	12.8	27.2	111.4%
WEL Networks	24.7	NA		19.9	NA	
Northpower	19.4	NA		18.2	NA	
The Power Company	20.4	16.1	-21.4%	19.9	15.6	-21.4%
Counties Power	11.8	NA		10.3	NA	
Electra	8.1	10.4	28.7%	7.2	10.5	44.9%
Marlborough Lines	7.1	NA		7.0	NA	
Waipa Networks	8.2	NA		8.2	NA	
Westpower	2.5	4.7	84.5%	2.7	4.9	79.3%
Network Waitaki	4.6	5.8	26.2%	4.5	6.3	41.6%
Scanpower	2.2	NA		2.1	NA	
Buller Electricity	3.1	NA	1.1%	3.1	NA	111.4%

Source: NZIER

2.3. Conclusion

Overall the readily available information on the allocation of Transpower charges is not adequate for a detailed assessment of the EDB methodology being implemented. The sample of pricing methodologies indicate that the most common method of allocating transmission costs is based on contribution to RCPD (for customers for whom this can be measured) and contribution to anytime maximum demand for mass market customers.

Most of the EDB pricing methodologies that we have reviewed, base their allocation of transmission charges on the method used by Transpower used to allocate the charges. Accordingly, the proposal to abolish RCPD based allocation and implement a combination of area of benefit charge and residual charge allocated on historical network use is likely to be replicated in EDB pricing.

3. ENA pricing options

3.1. Introduction

The comparison of the pricing options in the ENA paper includes the feasible components of pricing, and a set of criteria that cover both the objective of achieving cost reflective pricing and the key stakeholders that would need to be considered. The assessments of each of the pricing components provide a good starting point for discussion of the options.

Rather than comment on the ratings for the individual pricing component we make the following types of comment in this section:

- general observations on how the pricing options summary fits with the current practice by EDB could contribute to the discussion about how pricing methods might change
- specific observations on some of the components of the summary assessment of the options

3.2. Pricing options

The summary assessment suggests five pricing options: 'time of use', 'customer peak demand', 'installed capacity', 'booked capacity' and 'network peak demand'. Our general observations on the choice of components are:

- it would be helpful if the summary table linked the options to current EDB pricing practice and in particular:
  - link these options to a description of how widely they are used across EDB and customer groups at the moment
  - acknowledge the continuation of the use of simple energy supplied (cents/kWh) as an option to reflect a key driver of current practice.
- the summary table presents the components as separate options when the current practice of EDB seems to have multiple components for different customer grouped and sometimes two or more fixed charge components along with an energy supplied component for the same group of customers
- it would be useful if the discussion of the pricing options considered their compatibility with the proposed changes to the transmission pricing methodology or at least how transmission pricing components could be passed through to customers under the different pricing options.

Specific observations on the choice of pricing options within the table are:

- it should indicate what if any options currently used by EDB are not covered in the table – for example it seems that the kVA and kVAr charges used by some EDB could fit under the peak demand charges but it is not clear that they do

- it should clarify whether fixed time (daily/monthly) charges are expected to continue along-side all of the price components or whether they are considered redundant for some or all of the components.

3.3. Criteria

The summary analysis suggests criteria grouped under the headings 'economic efficiency', 'consumers', 'retailers' and 'distributors'. The efficiency criteria seem to define two separate problems:

- a cost recovery problem – how to ensure that current network users pay for the services they demand from the network
- signalling future network costs.

The remaining criteria reflect stakeholder (consumer, retailer and distributor) attitudes to the components and focus on how the stakeholders would be affected by the each of the pricing components:

- whether consumers will understand and act on the signal sent by the change in distribution pricing
- how much effort is required for retailers and distributors to implement the change and what will be required to ensure the implementation is compliant with regulations.

Overall the criteria are a reasonable starting point for comparing the options. We have read the assessments of the options in the summary table as broad and indicative. We suggest the following as next steps for the refining the assessments and anchoring them more firmly to the available evidence:

- the assessment of the options against 'efficient cost recovery', 'causer beneficiary pays' and 'signals efficient investment in emerging technology' could be quantified now based on analysis of existing pricing methodologies and customer groupings. The sample of the pricing methodologies all focus on efficient cost recovery and causer beneficiary pays across customer groups. This information should provide the basis for assessing how the recovery of cost would be different under the pricing component options. The analysis of solar PV in Section 1.3 of this report provides a rough starting point for assessing the current and future exposure of EDB cost recovery under the different price components for this emerging technology
- consumer ability to understand alternative price components and their response could be partly gauged from the diverse natural experiments underway across EDB due to the variation in their pricing plans as well as the changes in pricing plans that have been implemented by EDB over the past 5 to 10 years
- as most retailers operate across multiple EDB many of them should already be used to be operating with the range of pricing options listed in the summary table. The extent to which their billing systems can accommodate these options and how they bundle distributor pricing would provide a cross-check on the feasibility of wider geographical use of the summary table pricing options

- many of the EDB pricing methodologies we reviewed include comment on both areas for improvement in pricing plans and an indication of the priority and timing for change. A summary of these statements would complement the assessment of distributor readiness and capacity to adopt each of the components
- overall it would be helpful if the summary table included an assessment of the 'case for change' for types[9] of EDB for each of the components to provide a sense of which component or bundle of components would be most effective in resolving the cost recovery issues faced by EDB.

3.4. Conclusion

The summary table describes the main types of pricing option available to EDB and includes criteria that cover both achieving the objective of efficient pricing and considering stakeholder attitudes. The next steps in improving the assessment of the components could be:

- recognising that EDB are likely to use bundles of the components for the same group of customers rather than one component
- cross-checking the assessment of the components against current EDB pricing plans, recent experience of rationalising pricing plans and stated intentions for change
- describing the case for change for types of EDB.

[9] Type of EDB could be based on size of network, mix of customers or existing charging structure.

Appendix A ToR

There are 3 deliverables. First a report to be part of submissions on 20 December covering:

a) An estimate of the number of ICP and volumes by EDB for different forms of pricing and the relative importance where there has been and is expected to be either growing demand and or uptake of PV/EV/batteries. This will assist identify EDB with material volumes/ICP and the level of divergence between current tariff structures where new pricing frameworks to manage emerging technologies most important.

b) TPM pass through issues such as whether pass-through to mass market and C&I sectors is consistent with current tariff structures or the pricing options in the ENA paper. This may need to be undertaken on a sample of EDB rather than all EDB (eg one NI and one SI EDB such as Vector and Orion). Indirectly related to TPM is to consider how a change in DGPP (ACOT) as proposed by the EA should affect EDB prices.

c) A review of the analysis of pricing options in the summary table on pp 73-75 of the ENA paper. The review will consider whether other pricing options should have been considered along with the 5 pricing options in the ENA paper, if the assessment criteria are appropriate and if the subsequent analysis is reasonable.

There are other material issues the ENA paper does not consider such as whether the underlying cost allocation to different classes of consumers is efficient in the first place including the treatment of stranded assets. Another topic is whether changed pricing structures and any resulting change in consumer behaviour have or should have any feedback loop into investment and operating decisions by EDB. Whether we need to respond in detail on these topics in this submission round is still under consideration. As the project proceeds the scope and if needed the budget may change to accommodate any change in focus for the written NZIER advice.