ELECTRICITY PRICE REVIEW

HIKOHIKO TE UIRA

TECHNICAL PAPER
To accompany FIRST REPORT

30 August 2018

New Zealand Government

Contents

Introduction

The Electricity Price Review – *Hikohiko te uira* – released its first report for discussion on the state of New Zealand's electricity sector dated 30 August. This technical paper is a companion to that report, and is intended for a specialist audience.

It includes a technical discussion on these topics:

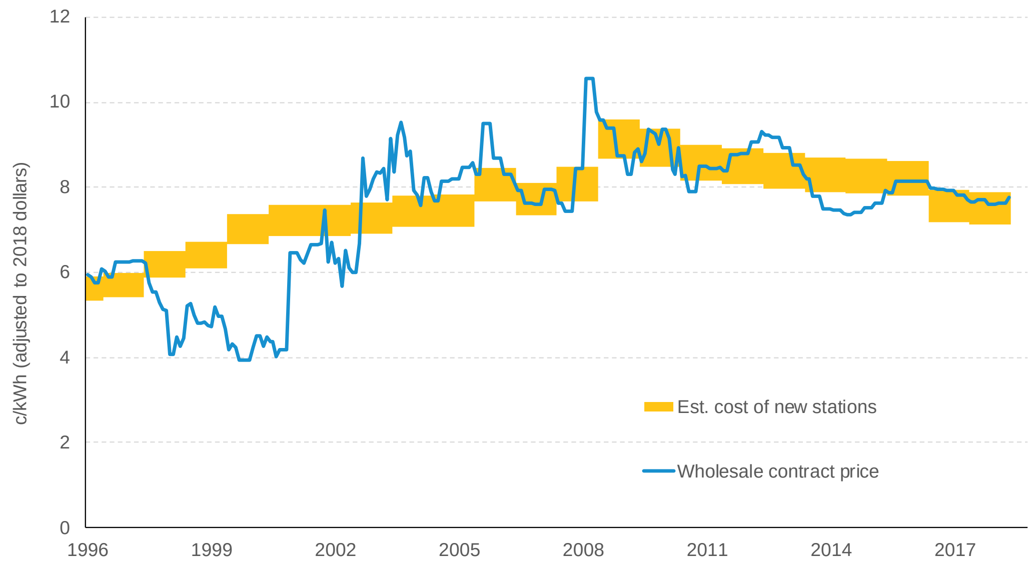
- Pricing analysis comparing wholesale electricity contract prices against the cost of building new power stations – page 32 of the first report;
- The financial performance of generators and retailers, and whether they have been making excessive profits – page 46 of the first report;
- Analysis of the allocation of distribution costs between businesses and residential consumers – page 61 of the first report;
- Technological advances in the electricity sector, including case studies of hydrogen fuel cells, large scale batteries, electric vehicle recharging technology, and technology for managing electricity networks – page 63 of the first report.

Wholesale electricity contract prices and the costs of building generation

The first report includes a comparison of wholesale electricity contract prices and the costs of building new power stations, to assess whether pricing is efficient in the generation sector. This comparative framework is similar to that adopted in earlier reviews, in particular the 2009 Ministerial review of electricity market performance[1] and the 2007 market design review by the Electricity Commission. [2]

The chart from the first report is reproduced in Figure 1. Readers are referred to page 33 of the report for a discussion of the results of the analysis. In this technical paper, we describe the data sources used to compile the chart.

Figure 1: Wholesale contract prices versus cost of building new power stations



Source: Concept Consulting analysis. Prices and costs are adjusted for inflation and expressed in 2018 dollars.

Wholesale contract price data

Contract prices provide a measure of wholesale electricity payments at different points in time. Because prices vary depending on individual contract terms, the data used for the analysis seeks to standardise the basis for comparison as far as practical. In particular:

- Prices are for contracts of one-year – to exclude seasonal and other short-term influences;
- Prices are for baseload contracts – the volume profiles are flat across each day, week and season;
- Contracts signed close to the commencement date for supply have been excluded, where information on execution date was available. This is to reduce the impact of short-term hydrology changes on reported prices. Put another way, the contract

[1] Ministerial review of electricity market performance, improving electricity market performance, pp 93-95, August 2009.
[2] Electricity Commission, issues paper, pp 3-52 to 3-58, October 2007.

prices are intended to reflect the expectation of prices under average hydrological conditions.

Because contract price data is not available on a consistent basis, different sources have been used. For simplicity, these are presented as a single wholesale price indicator in figure 1. The sources are:

- August 1996 to September 2004 – New Zealand tariff and fuels consultants retail electricity indicator price (the NZTF index). This data source was used in the Electricity Commission's issues paper in 2007. Readers are referred to that paper for more detail;[3]
- October 2004 to September 2009 – EnergyHedge prices. This data source was also used in the Electricity Commission's issues paper in 2007. Readers are referred to that paper for more detail;[4]
- October 2009 to December 2018 – prices for Otahuhu baseload futures contracts published by the Australian securities exchange. Contracts with trade dates close to the commencement date[5] have been excluded to reduce the impact of short-term hydrology changes.

Although the sources differ in some aspects, they all reflect actual market data. We therefore consider the data to be a reasonable indicator of the contract prices prevailing in the wholesale market at different points in time.

Costs for building new generation

Unlike contract prices, the costs of building new generation cannot be directly observed. Instead, the most likely type of new generation to provide firm baseload electricity needs to be identified for each point in time. Once the type of generation (such as gas-fired, geothermal, etc.) is identified, the expected cost of electricity can be calculated in dollars per MWh of output, based on estimates of construction, fuel, maintenance costs and hours dispatched per year.

It is important to note the analysis seeks to identify the cost of building new generation based on prevailing knowledge at different points in time.

For 1996 to 2008, we used the costs of building gas-fired combined cycle power stations. These were the predominant form of new baseload generation in the period. The estimated costs of building gas-fired combined cycle stations were drawn from the 2009 Ministerial review.[6] We are not aware of any concerns expressed about these estimates. The only adjustment made to the data was to convert nominal dollars to real 2018 dollars using the Consumer Price Index (CPI).[7]

[3] Ibid at 2.
[4] Ibid at 2.
[5] less than six months.
[6] Ibid at 1.
[7] For simplicity, CPI was used as a common deflator throughout the report. An alternative deflator is the Producer Price Index (PPI). However, while the CPI and PPI series diverge over short time frames, they have been similar over extended periods, including in the period covered in figure 1.

For 2009 to 2018, we drew on sources that presented estimated costs at different points in time. The sources were:

- 2009 Ministerial review report.[8]
- 2012 report from the Ministry of Economic Development;[9]
- 2014 report from the Electricity Authority;[10]
- 2016 report from the Ministry of Business, Innovation and Employment.[11]

While the sources differ in detail, they present a consistent view that geothermal stations, rather than gas-fired power stations, were the main source of new generation after 2008. This reflects the switch in the relative economics of investment in these types of power stations, with the launch of the emissions trading scheme at that time.[12]

The sources indicate the cost of building new generation was around 7.5 c/kWh to 8.5 c/kWh in 2009 and remained close to these levels until 2016, when there was a decline to 7.5 c/kWh (all values in nominal dollars of the day and not inflation adjusted).

Our analysis adopts 8 c/kWh as the mid-point cost estimate for 2009 to 2016, and 7.5 c/kWh thereafter (all expressed in dollars of the day). These values were adjusted into 2018 dollars to take account of inflation. The resulting estimates are as follows:

Table 1: Estimated costs of building new generation 2009 to 2018 (real $ 2018)

Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Cost estimate	9.1	8.9	8.6	8.5	8.4	8.3	8.3	8.2	7.6	7.5

These values appear reasonable, compared to other, informal, sources. For example, during the engagement process for the review, one stakeholder (not a major generator) told the review “new geothermal capacity costs approximately $75/MWh” to develop.[13]

Finally, there is inherent uncertainty about costs and for that reason the estimates shown in figure 1 are presented as a band of +/- 5 percent around the mid-point values.

[8] Ibid at 1, figure 33.
[9] Ministry of Economic Development, Introducing the electricity demand and generation scenarios, July 2012, Figure 3.
[10] Electricity Authority, Analysis of historical electricity industry costs, January 2014, Figure 17.
[11] Ministry of Business, Innovation and Employment, Electricity demand and generation scenarios, August 2016, Figure 8.
[12] Some new wind generation was also developed after 2008 – however it was not the major source of new supply. Looking ahead, wind generation may supplant geothermal plant as the main new source of grid-connected generation, especially as wind turbine costs have been falling and geothermal plant is more sensitive to rising carbon prices.
[13] $75/MWh is equivalent to 7.5 c/kWh.

The financial performance and profits of generators and retailers

The review was asked to examine generators' and retailers' financial performance and whether they have been making excessive profits.

It was not possible to undertake a definitive assessment of these issues because of data limitations. In particular, a comprehensive assessment would require detailed information on the capital and operating costs for generation and retailing activities. This data was not available.

For this reason, the review undertook a high level analysis to examine financial performance trends over time. Furthermore, because robust data for generation and retailing as separate activities was not available, the analysis examined the financial performance of these activities on a combined basis. [14]

The review collated information from company annual reports on net operating cash flows (excluding interest and tax) for companies with substantial interests in electricity generation, retailing or both. A cashflow measure was used because it is subject to fewer accounting adjustments than non-cash measures. It therefore provides a more consistent basis to make comparisons over time. This measure captures the effect of changes in electricity sale prices and variations in operating costs – such as movements in fuel costs. However, it does not account for capital costs. These are a substantial component of total costs – especially for generation activities. For this reason, the analysis by itself cannot be used to assess performance at any particular point. However, the analysis is useful to understand trends.

Cashflow data from 1996 to 2017 was collated for Contact Energy, the Electricity Corporation of New Zealand, Genesis Energy, Mercury Energy, Meridian Energy and Trustpower.[15] Other companies with generation or retail activities were excluded because they did not publish accounts (such as Nova Energy), undertook activities which meant their reported cashflows did not primarily reflect electricity generation and retail activities (such as Natural Gas Corporation), or were small relative to the size of the overall sector.

For the six entities included in the analysis, some of the reported cashflows reflected activities unrelated to New Zealand electricity generation and retail operations. For example, the data includes cashflows from gas retailing in New Zealand and generation or retail investments in Australia. It was generally not practical to exclude these cashflows. However, we were able to adjust cashflows for Genesis to exclude an estimate of cashflows associated with its investment in gas and oil activities.[16]

No cashflow estimates are presented for 1999 to 2002. Significant industry restructuring occurred then, making it impossible to reliably identify the cashflows associated with generation and retail activities. In particular, reported results were substantially affected by the sale and purchase of more than 30 retail businesses following the lines-energy separation in 1999, and the formation of three new entities from the Electricity Corporation of New Zealand. In addition, TransAlta, a major electricity retailer and generator, was purchased by the Natural Gas Corporation in 2000, which sold its retail and generation interests shortly after.

The cashflow estimates prior to 1999 are based on the annual reports of Contact

[14] Some companies reported retail or generation data for some years. However, the data was not consistent over time, so was not used in this analysis.
[15] Excluding the period when Trustpower was an electricity distributor.
[16] The operating cashflow estimate was based on the earnings before interest, tax, depreciation and amortisation reported for the oil and gas segment of Genesis' business.

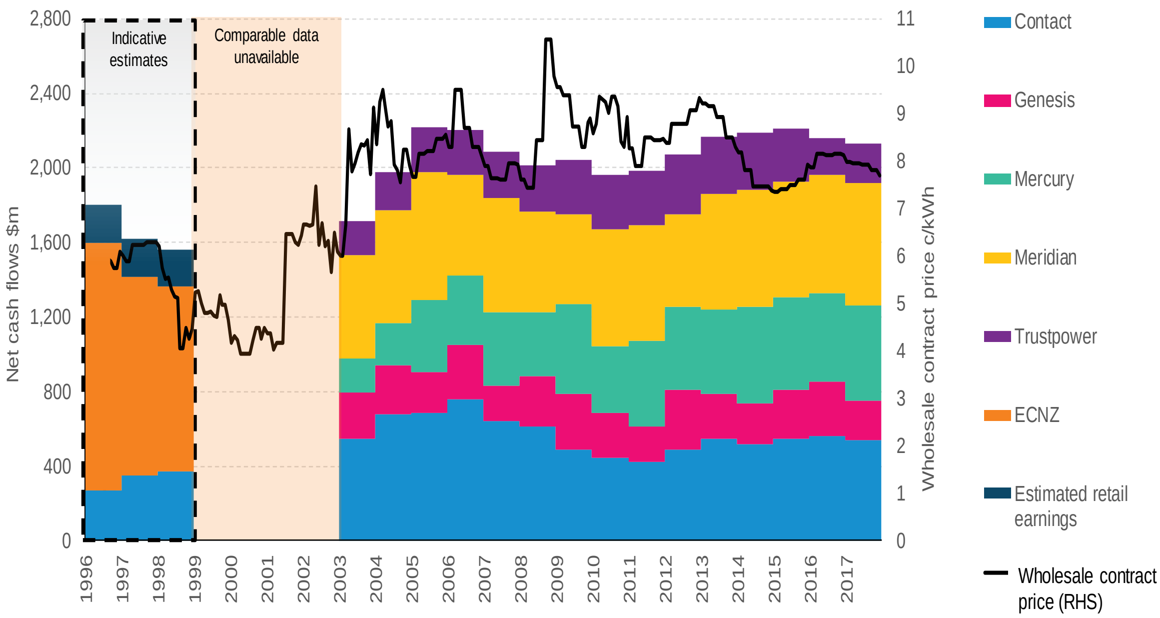
Energy and the Electricity Corporation of New Zealand, the two major generators at the time. Neither organisation had any substantial retailing operation. At that time, electricity retailing was undertaken by more than 30 retail-distribution businesses. These businesses did not separately report cashflows for their retail arms. For this reason, an estimate of cashflows associated with retailing was required for 1996-1998. This was estimated at an aggregate industry level, based on an assumed annual pre-tax margin of $75, over the wholesale price, per retail customer account, multiplied by 1.5 million accounts.

The retail margin assumption is based on transaction prices reported for retail businesses when they were sold in 1998-1999.[17] While there is uncertainty over the estimated retail margin, it is a small component of total generation and retailing cashflows, and therefore the overall results are relatively insensitive to this estimate.

The nominal cashflow data for the 20 years was converted to 2018 dollars using the Consumer Price Index. In addition, the volume of electricity generation and retail sales increased in the period covered by the data. All things being equal, a larger generation-retail sector would be expected to produce more net cashflows. For this reason, the reported cashflows for each year were scaled to reflect the 2017 level of grid demand, and to obtain a more consistent comparison through time.

The results of the calculations appear in figure 20 of the report. The wholesale contract price series (discussed in the preceding section of this paper) was superimposed on the chart for comparative purposes. That chart is reproduced as Figure 2 below. Readers are referred to the first report for a discussion of the results of the analysis.

Figure 2: Cash flows for generators and retailers



Source: Concept Consulting analysis of company reports and other data.

[17] Grant Samuel & Associates Limited, Appraisal Report Contact Energy Limited, May 2001.

The allocation of distribution costs between business and residential consumers

As noted in the *Prices* section of the first report, before 1990 commercial and industrial consumers typically paid a bigger share of common distribution costs, while residential consumers paid a smaller share. This was reversed over time. Shifting costs from businesses to householders was the biggest factor in residential price increases between 1990 and 2018 (a development that began in the early 1980s). During this period, distribution charges for residential consumers rose 548 per cent, while those for commercial and some industrial businesses fell 58 per cent.[18]

Given the scale of this reallocation, we raised the question of whether the reallocation process by electricity distributors has gone too far (see *Distribution*). To get a clearer idea of the current allocation, we compared the share of total distribution charges paid during 2017 by residential consumers on each network with their share of energy used on that network. We compared those payments with what are called incremental and stand-alone cost allocations.[19] The analysis was repeated for business consumers.

This analysis, with qualifications, gives a reasonable overview of how costs are allocated between residential and business consumers.

Compared with usage[20], we found businesses were paying, on average, less than a proportionate share of distribution charges, and residential consumers were paying more. We estimate householders' average yearly bill could fall by $90 (including GST), or about 4.5 per cent, if business and residential allocations were undertaken on a more equivalent basis. Businesses' average yearly bills would increase by about 5.5 per cent. Having said that, there are differences across networks. For some networks, the allocation of distribution charges for residential and business consumers appears to broadly align with usage shares.

Analysis of shared network cost allocation

Our analysis focussed on the allocation of common distribution costs; that is costs which cannot be attributed to a single consumer or group of consumers.

The costs associated with shared network assets are common distribution costs. Shared network assets include the non-peak-demand-driven component of the main power lines and substations in a network area, and a distributor's running costs.

Some assets and the associated costs are not common, such as those for power lines dedicated to a large factory or connecting remote consumers. Further, we consider the peak-demand-driven component of network costs are not common, as they can be allocated to consumers based on their contribution to system peak demand. We discuss the distinction between peak-demand-driven and non-peak-demand driven costs later in this paper.

Our aim was to estimate the range of cost allocations to residential and business consumers which would be subsidy-free for a given share of network usage and to understand the implications of alternative cost allocations within this range.

In economic terms, a subsidy-free cost allocation is one where all users (or groups of

[18] Excludes the effect of GST changes.
[19] See *Analysis of shared network cost allocation* for definitions of stand-alone and incremental costs.
[20] 'Usage' is based on both peak kW demand and annual kWh aspects of network usage.

users) pay an amount between the incremental and stand-alone cost of supply. Conversely a cross-subsidy exists if any user (or group of users) pays less than its incremental cost, or more than its stand-alone cost.

Incremental electricity network costs are those costs which are solely attributable to a consumer group – e.g. connection assets, or low-voltage network assets that solely supply a consumer group. For residential consumers they include their assessed contribution to network peak demand-driven costs, plus the costs of any "connection assets" (such as poles and fuses) needed solely for supplying residential consumers.

Stand-alone electricity network costs for a consumer group are equal to the network costs that would still be incurred if the only consumers served by a network was that consumer group. For example, a large proportion of the core network assets would still be required if the network was only serving residential consumers, or only serving business consumers. They can also be thought of as the lowest cost alternative for serving each consumer or consumer group. In this analysis for residential consumers the stand-alone cost is estimated as the total network costs minus the incremental costs calculated for business consumers. For an individual consumer (as distinct to a consumer group) the stand-alone costs are capped at the costs of providing electricity services from self-generation (solar plus diesel) and batteries for a consumer who completely disconnected from the grid.

Our analysis involved four steps:

Step one – Compare the current share of distribution costs recovered from residential consumers for each network, with their share of network usage, then repeat this for business consumers.

Step two – Identify the factors which would drive a cost-allocation that was not directly proportional to share of usage.

Step three – Estimate the range of cost allocations to residential and business consumers which would be subsidy-free for a given share of usage, taking account of the factors identified in step two.

Step four – Estimate the impact on residential and business consumer bills for different subsidy-free cost allocations.

Step one – Assessing current share of costs

To understand the extent to which residential consumers now pay for shared network assets and whether there is significant variation between networks, our analysis first compared the share of distribution costs recovered from residential consumers for each distribution network, with their share of GWh consumed. The same analysis was repeated for business consumers.

Rebates or dividends are not included in the analysis because they are payments to some consumers in their capacity as "owners" of a local network.

Commerce Commission disclosure information for 2012 to 2017 provided the source data for this analysis. For each reported consumer category[21] we extracted and analysed data on GWh, number of consumers and network revenue recovered. We then manually classified each of the 1,100 different reported consumer categories into:

- Residential only;
- Business only;

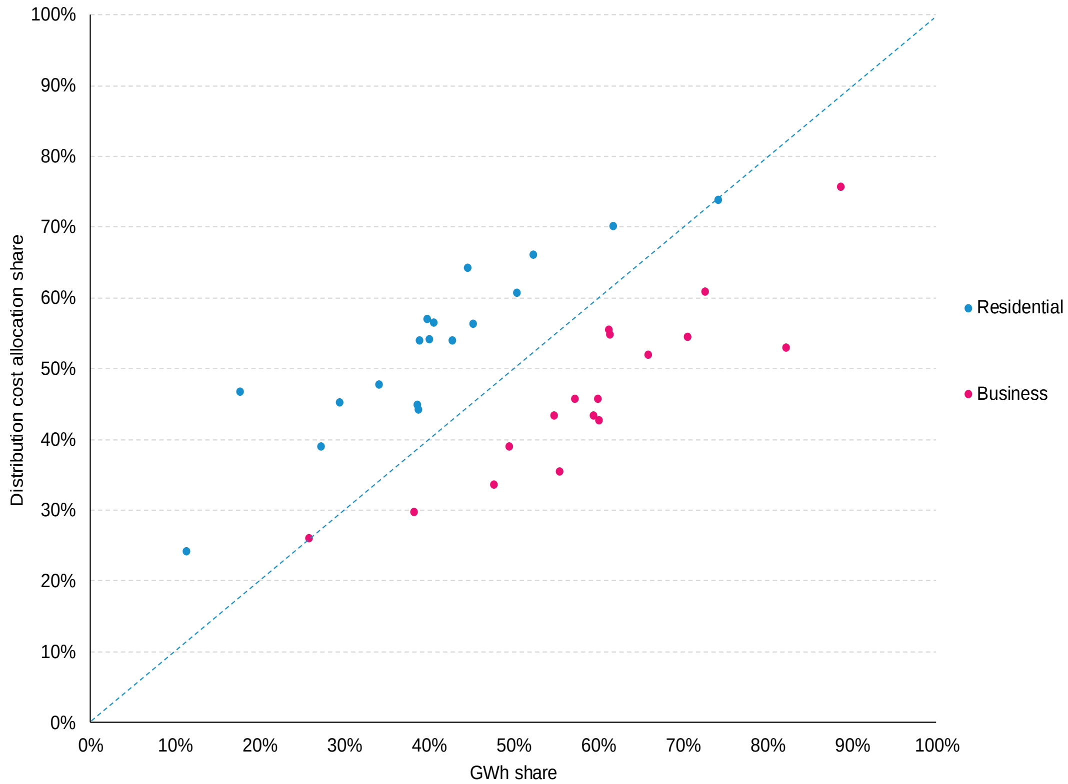
[21] Some networks have relatively few reported consumer categories (e.g. Westpower only has 7), whereas others have many more (e.g. Horizon has 89).

- General – i.e. residential and business.

For each network area we calculated the share of GWh consumed by residential consumers and business consumers and compared that with the share of distribution costs recovered from those consumer groups. We excluded those networks that did not have exclusively residential and business categories – i.e. they also have General categories – making it impossible to determine the exact proportions of costs being allocated to residential and business consumers.

The results are shown in Figure 3. The dots on the graphs represent the residential (blue dots) and business (red dots) consumer categories for different electricity distributors.

Figure 3: Observed comparison between GWh share and distribution cost allocation share for residential and business consumers for different electricity distributors



Source: Concept Consulting analysis of Commerce Commission 2017 data

If distribution network costs were entirely proportional to GWh demand, then the proportion of network costs recovered from consumers in that network area should equal their share of GWh demand. This would mean the dots would all appear on the 45° dotted line shown in Figure 3.

However, in almost all cases, residential consumers have been allocated a greater proportion of network costs than their GWh share (blue dots above the dotted line in Figure 3). It is the opposite for business consumers (red dots) – the red dots are the 'mirror' of the blue dots reflected across the 45° dotted line.

Step two – Identifying factors driving a 'disproportionate' cost-allocation

To consider whether such outcomes are an appropriate reflection of the underlying cost drivers, it is important to explore three key factors which mean that cost-allocation should not be entirely proportional to GWh demand.

First, only a proportion of network costs are driven by demand. Orion, the network company serving Christchurch and central Canterbury, estimates only 50 per cent of its network costs are driven by system demand in the long-run.[22] This means that if (for example), demand in Christchurch were to be 20 per cent higher in 30 years, the level of network costs needing to be recovered would be 10 per cent higher, all other things being equal.

The remaining, non-system demand-driven network costs are largely shared network assets. Where network assets are shared, it is not possible to directly attribute costs to one group of consumers or another, because the assets would be needed for either group. As noted above, the economic test for a subsidy-free allocation of shared network assets is whether the level of allocation to each consumer group is between the incremental and stand-alone costs of supplying that consumer group. The implication of this test is that there is no single cost allocation between consumer groups which avoids cross-subsidies, but rather a *range* of cost allocations which are subsidy free.

For network assets, the range between incremental and stand-alone is an extremely wide band. For example, Wellington Electricity's pricing methodology presents analysis (shown in Appendix A of this paper) which suggests that the incremental (termed 'Avoided' in Wellington Electricity's graph) to stand-alone range for residential consumers is between 25 per cent to 100 per cent of network costs.[23]

Secondly, of the system-demand-driven costs, it is peak MW system demand, not annual GWh demand that drives such costs. The consequence of this is that consumers who consume a greater proportion of their demand at times of system peak than average, should see a proportionately greater cost allocation of such demand-driven costs. In general, residential consumers contribute a proportionately greater amount to system peak than other consumers.

Lastly, there are some shared network assets which are not shared by some consumers. For example, consumers connected at the high voltage level, clearly do not share any low-voltage network assets.

Step three – Estimating the subsidy-free range of cost allocations

A simple model was developed that reflected the above factors and which enabled us to estimate the range of cost allocations to residential and business consumers which would be subsidy-free for a given share of GWh.

To provide building blocks for the model key assumptions were made, drawing on the discussion of the three factors in step two:

- Assume a proportion of network costs which are driven by system peak demand. The central value for this was 50 per cent, based on Orion's estimate (discussed in step two).
- Assume the contribution to system peak demand of residential consumers is 50 per cent peakier than that of business consumers[24 25]. This results in residential

[22] Section 7.1 of Orion's "Methodology for deriving delivery prices for prices applying from 1 April 2017".

[23] In this graph the Wellington Electricity analysis appears to relate to <u>all</u> network costs attributable to residential consumers, including demand-driven costs. If this is the case, then the Incremental lower boundary for residential consumers would be substantially lower than the 25 per cent value shown.

[24] We used the after-diversity contribution to system peak.

consumers being allocated a proportionately greater share of demand-driven network costs.

- Assume the incremental non-demand-driven network costs of mass-market consumers (i.e. residential and similar-sized small business) is 25 per cent of such costs, based on Wellington Electricity's estimate of all network costs as shown in Figure 6 in Appendix A.
- Assume incremental, non-demand-driven network costs of consumers connected to the high voltage (HV) network is 2 per cent of such costs – based on Wellington Electricity's estimate of the incremental costs of 'transformer' consumers.
- Assume 50 per cent of business demand is connected at the HV-level.

While the model is simple and doesn't take into account the specifics of individual network situations, it provides a first-order approximation of the nature and scale of the cost allocation issue.

Using the above parameters the model estimated the incremental and stand-alone range of cost allocations for a given residential share of total GWh network demand:

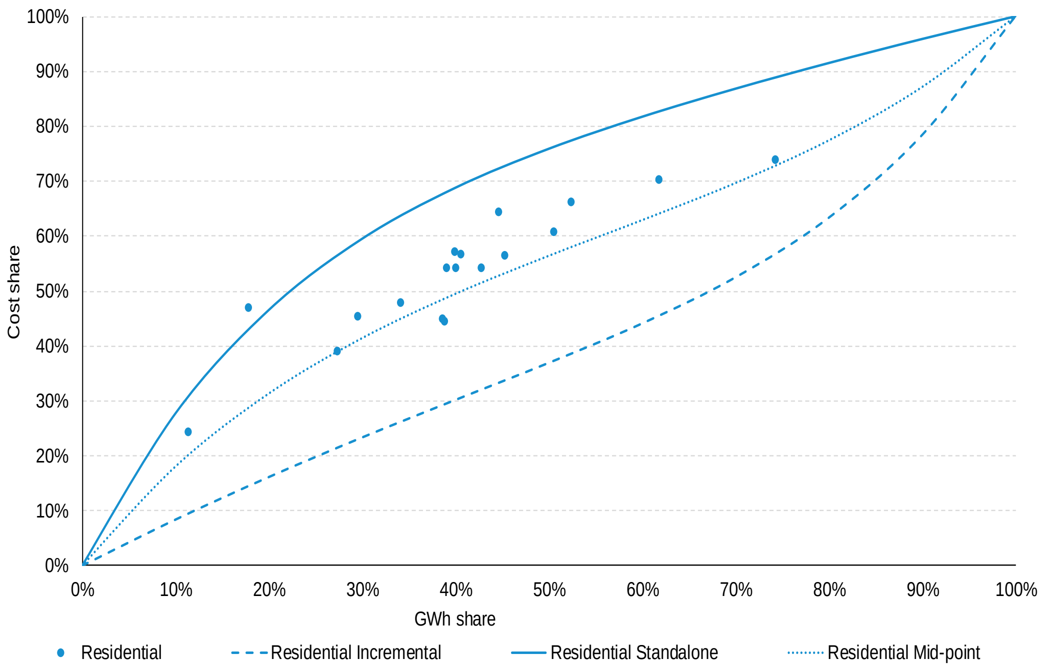
- The incremental bound for the range equals the demand-driven costs attributable to residential consumers plus the incremental level of non-demand driven network costs.
- The stand-alone bound for the range equals the demand-driven costs attributable to residential consumers, plus all the residual non-demand-driven network costs less those incremental costs attributable to business consumers.

The estimated incremental and stand-alone ranges for residential consumers were overlaid on the previous graph of observed cost allocation outcomes for residential consumers to give the results shown in Figure 4 below. The corresponding graph for business consumers is shown in

Figure 5. Each dot represents a different electricity distributor.

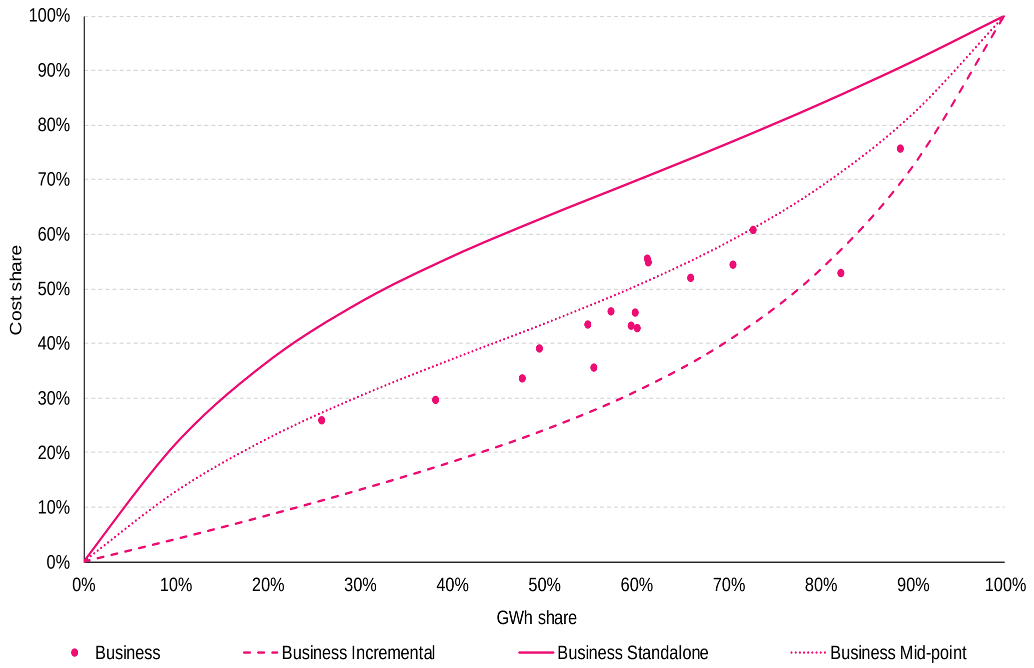
[25] This assumption reflects the widely held view that residential demand is appreciably more "peaky" than that of business consumers, however, we are not aware of any definitive data on this issue. As noted below, the overall results are not particularly sensitive to this specific assumption.

Figure 4: Comparison of estimated incremental and stand-alone distribution network cost allocation ranges for residential consumers, with observed actual 2017 allocations



Source: Concept modelling and analysis of Commerce Commission 2017 data

Figure 5: Comparison of estimated incremental and stand-alone distribution network cost allocation ranges for business consumers, with observed actual 2017 allocations



Source: Concept modelling and analysis of Commerce Commission 2017 data

Key observations from this analysis are:

- Residential consumers have higher incremental and stand-alone costs than business consumers. This is due to residential consumers having peakier demand and a significant proportion of business consumer demand being connected to the HV network.
- In almost all cases, observed network company cost allocation outcomes for residential and business consumers are within the incremental-to-stand-alone range appropriate to each consumer group – i.e. subsidy-free.
- There is variation as to where different distribution companies sit within the incremental to stand-alone range. This variation likely explains some variation in residential network costs between networks as reported in electricity pricing statistics such as QSDEP[26].
- The cost allocation outcomes for residential consumers tend to be at the upper end of outcomes which would be considered subsidy-free – i.e. closer to stand-alone, than incremental. The opposite is true for business consumers.

Step four – Estimating the impact of different subsidy-free cost allocations

Drawing on the results of step three, and using the same model, we then explored the impact of different subsidy-free cost allocations.

As noted, the observed cost allocations for residential consumers tend to be at the upper end of the subsidy-free range, and business consumers at the lower end. Anecdotal evidence suggests this is because network companies have generally used peak-demand-based metrics for allocating shared costs, even though such costs are not driven by peak demand.

Allocating shared network costs which are not driven by peak demand using peak demand metrics will result in residential consumers being allocated a high proportion of network costs.

To examine the outcomes from alternative shared-cost allocation approaches which would still be subsidy-free, we estimated the change in residential and business consumer bills if the following cost allocation approaches were implemented:

- a cost allocation to residential and business consumers set exactly mid-way between the incremental and stand-alone levels
- a cost allocation to residential consumers set at the incremental level – with business consumers effectively being allocated stand-alone costs.

The results are set out in Table 2.

Table 2: Estimated implications of alternative shared-cost allocation approaches

Allocation approach→	Mid-point between incremental and stand-alone for residential and business consumers			Incremental for residential consumers and stand-alone for business consumers		
	Change in network charge	Change in average bill ($)	Change in total bill	Change in network charge	Change in average bill ($)	Change in total bill
Residential	- 11%	- 90	- 4.5%	- 46%	-370	- 17.5%
Business	13%	525	5.5%	54%	2,200	23.5%

[26] Quarterly Survey of Domestic Electricity Prices (QSDEP) undertaken by MBIE.

Source: Concept modelling and analysis of Commerce Commission 2017 data

The sensitivity of the incremental and stand-alone ranges to variations in key assumptions were tested and the consequential change in residential and business consumer bills from moving to a mid-way or incremental cost allocation approach. The sensitivity analysis indicated the results were robust against a range of assumptions, with variation in the scale of effects.

Technology advances in the electricity sector

The following case studies are representative of the types of technological advances that have the potential to significantly disrupt aspects of the electricity market. The case studies presented are not intended to be an exhaustive list, but are examples of the types of developments that have occurred.

Hydrogen fuel cells

The Ene-Farm is a Japanese government-subsidised hydrogen project that provides power to 220,000 households, as of October 2017. The project is part of Japan's wider plan to make extensive use of hydrogen. The Ene-Farm model that was launched in 2012 can work with different types of gas (liquefied petroleum gas and domestic natural gas), from which it extracts hydrogen for its fuel cell. Toshiba said the current model has an efficiency rating of 94 per cent and emits 1.5 times less carbon than earlier models.[27]

Japan had a residential fuel cell target of 1.4 million units by 2020 and 5.3 million units by 2030. However, Bloomberg reported that government subsidies have been insufficient to offset high costs and competition from other technologies, causing Ene-farm sales to drop below intended targets. [28] In addition, Toshiba's exit from the project in July 2017 leaves just two Ene-farm suppliers: Panasonic and Aisin Seiki, which may hamper sales efforts.

Toshiba's exit from the Ene-farm project has allowed it to concentrate on other hydrogen projects. One of these is H2One, which is a commercial scale hydrogen fuel cell that delivers electricity and hot water. This technology is used by the Kawasaki King Skyfront Hotel in Tokyo to provide 100 kW of electricity and hot water. In this example, hydrogen is produced from a waste plastic and piped to the fuel cell.

Converting waste plastic and tyres into hydrogen for fuel cells is being considered in a number of jurisdictions. For example, PowerHouse, a UK company, announced this year it had begun plans to develop a network of up to 200 waste-to-hydrogen plants around the UK. [29] These will use a process called Distributed Modular Gasification, which uses ultra-high temperatures to decarbonise waste and turn it into a pure synthetic gas.

In March this year Berlin-based Home Power Solutions announced their Picea system - a hybrid storage system that combines batteries with hydrogen. Picea represents a development in domestic energy storage that could provide inter-seasonal storage, rather than the inter-day storage provided by current systems.

Picea is due for release in October 2018. It has been designed to enable a four-person German household to run off solar and battery storage in summer, while storing enough hydrogen to cover energy use over the winter.

A typical domestic Picea system will have a peak electrical output of 20 kilowatts, a continuous power rating of eight kilowatts, and will be able to store electricity for thermal, daily and seasonal use. The daily storage capacity amounts to 25 kilowatt-

[27] Japan for sustainability, Toshiba Announces Launch of New Ene-Farm Household Fuel Cell, March 2012.
[28] Article for Bloomberg, Japan's Hydrogen Goals Need More Than Panasonic Fuel Cells, 10 October 2018.
[29] Article for gasworld, PowerHouse Energy to turn waste into hydrogen, 14 April 2018.

hours.[30] In addition, Picea's thermal storage tank will be able to deliver up to 45 kilowatt-hours, with 350 kilowatt-hours to one megawatt-hour of seasonal storage capacity.

Hydrogen fuel cell applications such as H2One and Picea can provide longer term energy storage than current batteries. However, it remains uncertain whether they will prove cost effective when measured against improving battery technology.

Large scale batteries

The Hornsdale Power Reserve battery in Australia is an example of a large scale battery project. It has an 100 MW discharge, a 80 MW charge, and a storage capacity of 129 MWh. This represents about 75 minutes of electricity at full discharge.[31]

The battery is used to stabilise the South Australian electricity grid, facilitate integration of the state's renewable energy and help prevent load shedding. The Australian Electricity Market Operator said the project could provide a range of valuable power system services, including rapid, accurate frequency response and control.[32]

In New Zealand, Mercury Energy recently deployed a one MW, grid-connected, two battery unit as part of a project to test the direct integration of batteries into the national electricity grid, and to provide insight into the relationship between storage and Mercury's renewable hydro and geothermal electricity generation.[33] It is the first large-scale battery to be directly connected to the national grid in New Zealand.

Vector has also invested in one MW batteries to support areas of demand growth and to defer costly upgrades of substations in its network - for example in Glen Innes, where a one MW battery can provide the electricity needed to power 450 average homes for 2.3 hours.[34] For distribution networks, battery can help to reduce peak demand, extend the life of network assets such as substations, and defer capital expenditure.

Smart network tools and applications

Many New Zealand electricity distributors are investing in technologies to improve network management and services. Some recent examples include:

- Ashburton-based distributor EA Networks and Greymouth-based distributor Westpower are introducing a distribution management system that will enable them to take advantage of smart technology within their networks, including two-way power flows from consumers with solar panels.[35]

- In 2015 Alpine Energy's included a bespoke geographic information system into its supervisory control and data acquisition control system, to provide enhanced network detail for dealing with storms and outages.

- Unison is using real time data to provide dynamic rating information, which will be used to inform decisions on how it loads its electrical assets at any given time,

[30] Article for GreenTechMedia, Seasonal Storage for Homes? German Firm Sells Residential Batteries Tied to Fuel Cells, 26 March 2018.
[31] Australian Energy Market Operator, Initial operation of the Hornsdale Power Reserve Battery Energy Storage System, April 2018.
[32] Ibid at 31.
[33] Article of Energy News, Mercury unveils NZ-first 1 MW grid-tied battery, 22 August 2018.
[34] Vector media release, Vector unveils Asia Pacific's first grid scale Tesla powerpack, 20 October 2018.
[35] Article for Energy News, EA Networks rolls out ADMS and mobile wi-fi, 23 Jul 2018.

based on a number of key variables such as wind and ambient temperature. This replaces the traditional industry approach to asset management, which uses standardised information from the manufacturer; expected lifecycle of an asset, and a scheduled maintenance programme. Unison expects this new approach to improve network reliability through better utilisation of existing assets, with the additional benefit of deferring large capital expenditure.[36]

Nissan's free recharging offer

Nissan is offering households in the United Kingdom and the United States of America free power to recharge their Nissan Leaf electric vehicles.

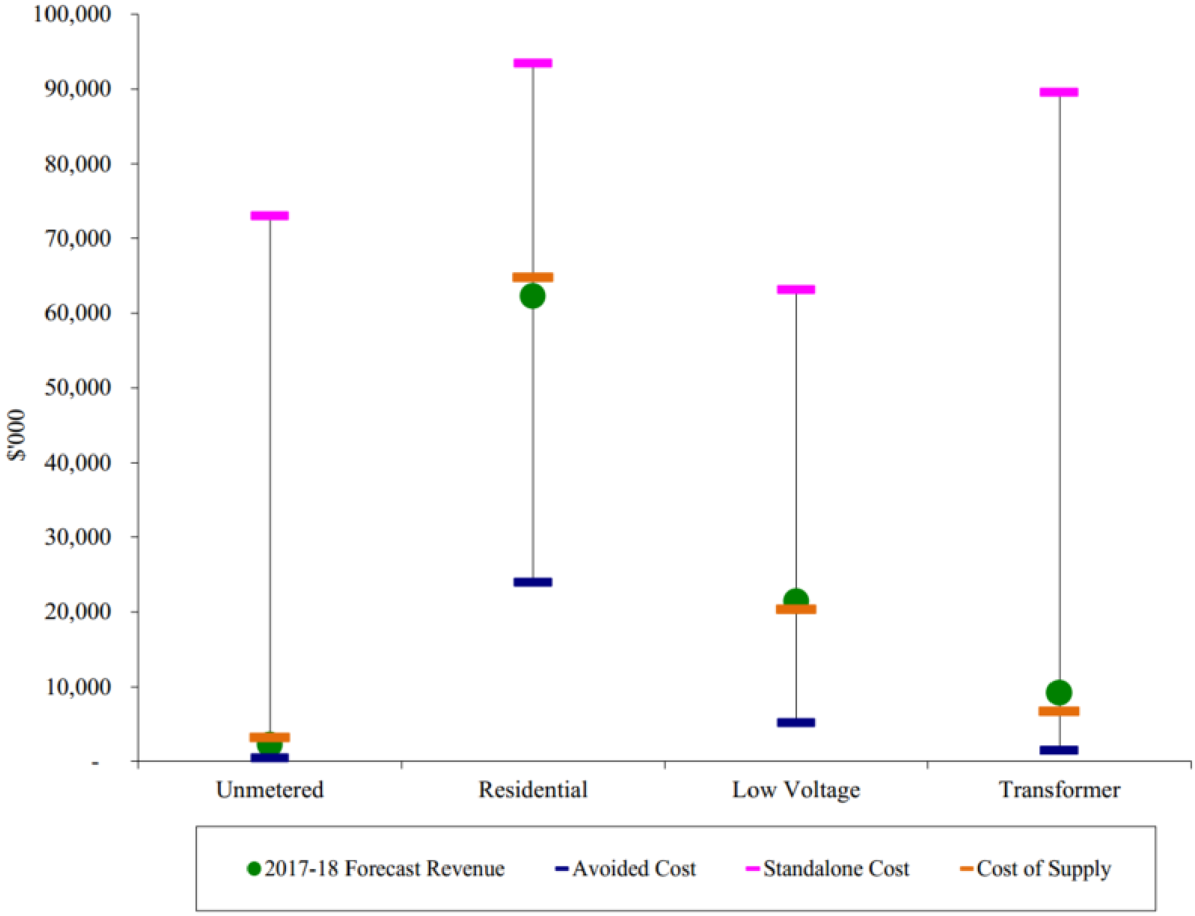
- In the United Kingdom, Nissan has partnered with retailer Ovo to offer a two-way charger as part of a new electricity deal.[37] This will allow the owner to provide electricity from their car's battery into the power grid. In exchange the car can be charged at no cost. Under the arrangement Ovo takes over the management of the car's battery, with owners able to set a minimum amount of charge they want for the next day. Ovo will then trade electricity from the battery, topping it up during off-peak periods when power costs less, and selling it at peak times.[38]
- In the USA Nissan began offering a free charging programme in July 2014.[39] The programme, offered in 25 cities provides two years of no-cost public charging with the purchase or lease of a new Nissan Leaf.

In New Zealand, ChargeNet has created 94 rapid charging locations and 27 standard chargers (as of June 2018), with an aim of reaching 105 rapid chargers by 2018/2019. Vector has developed a phone app that allows users to find and get directions to these chargers, as well as information on port type, charger type, and availability.

[36] See the Unison website for more details.
[37] Article for The Memo, Nissan offers free electric car charging – if you give back to the grid, 3 October 2017.
[38] Article for The Guardian, Electric car owners 'can drive for free by letting energy firms use battery', 2 October 2017.
[39] Article for chargepoint, Nissan Launches Programs to Make Leaf Charging Free and "EZ".

Appendix A: Wellington Electricity's incremental versus stand-alone analysis

Figure 6: Wellington Electricity's comparison of avoided costs, stand-alone costs, costs of supply, and forecasted revenue by consumer group



Source: Wellington Electricity Lines Limited, 2017/18 Pricing Methodology Disclosure, figure 2.