Analysis of historical electricity industry costs

Final report

21 January 2014

Market Performance

Version control

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Executive summary

The electricity industry has gone through a number of significant changes since the 1970s. Although charges to consumers have increased in nominal terms, increasing by an average of 4% per annum since 1996, in real terms they are not much higher now on average than they were in the early 1980s. This is not true for individual consumer types. Residential consumers have seen significant increases in real terms, while commercial consumers have experienced a significant reduction in charges.

To explore possible drivers of the changes in prices, the Electricity Authority (Authority) has prepared a breakdown of electricity industry costs since 1974. The methodology used by the Authority measures the total historical cost of supplying electricity to consumers, and compares those costs to historical retail charges. This review is not focused at measuring whether those retail prices are 'efficient' in an economic sense. The Authority has estimated the annual cost of generation using historical capital and operating costs in order to estimate the total average cost of supplying electricity to consumers.

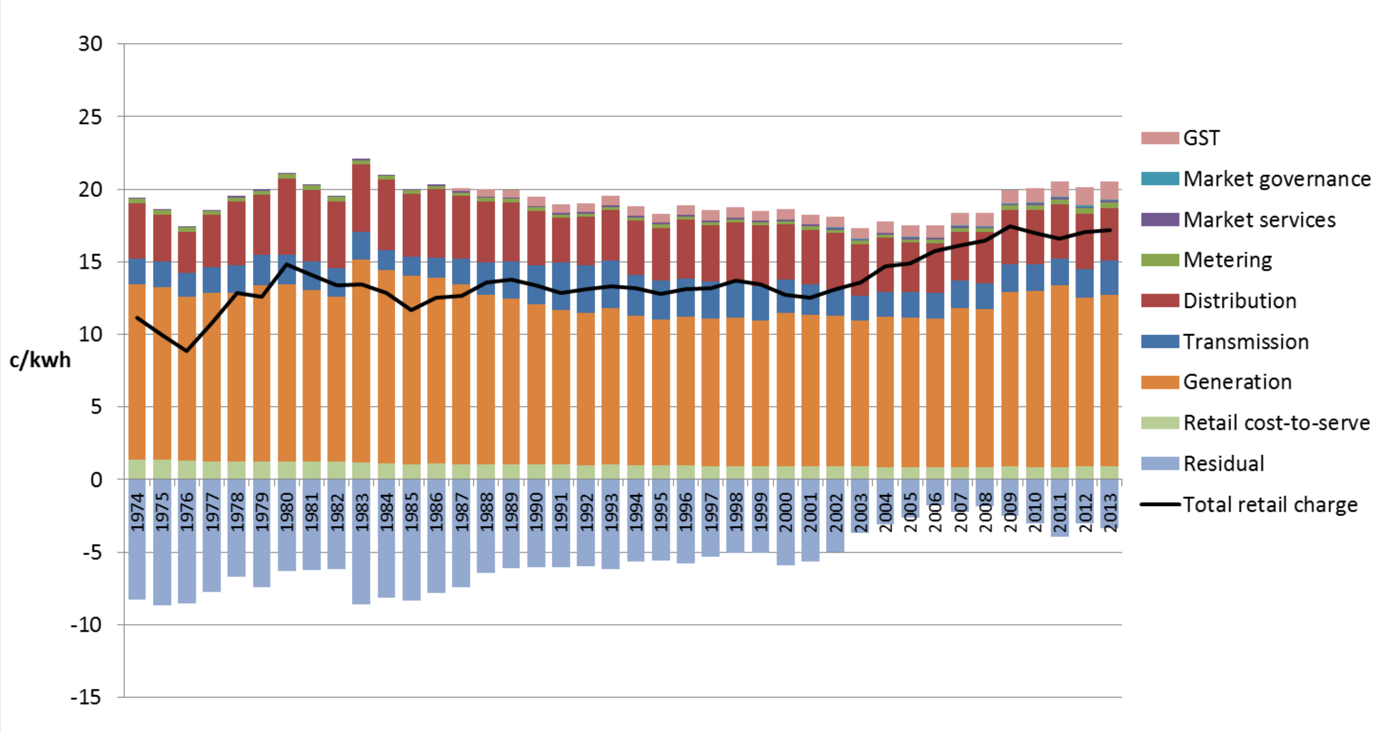
The analysis is based on Ministry of Business, Innovation and Employment (MBIE) data, and data from a range of other sources including New Zealand Electricity Department and other company annual reports and public documents. MBIE is currently investigating a number of issues relating to the recent supply of data published in the Energy Data File. Initial indications are that the supplied data may not fully account for residential customer discounting, and so may overstate retail prices over the past few years. As this analysis relies on these figures, the results below should be treated as provisional. The effect of any adjustment will be to lower the prices paid by residential consumers below those used in this analysis. This would reinforce the key conclusions of the analysis.

The methodology and models used by the Authority have been peer reviewed. The review concluded that the methods, data and modelling are fit for purpose.

The following chart shows changes in modelled cost components averaged for all consumer types between 1974 and 2013. The 'residual' shown in light blue at the bottom of the graph represents the difference between the estimated total cost to serve consumers, and total retail charges. This margin is negative across all the modelled years, implying an under-recovery relative to estimated historical costs.

Figure 1 Modelled cost components between 1974 and 2013

Averaged for all consumer types



Source: Electricity Authority

Real $2013

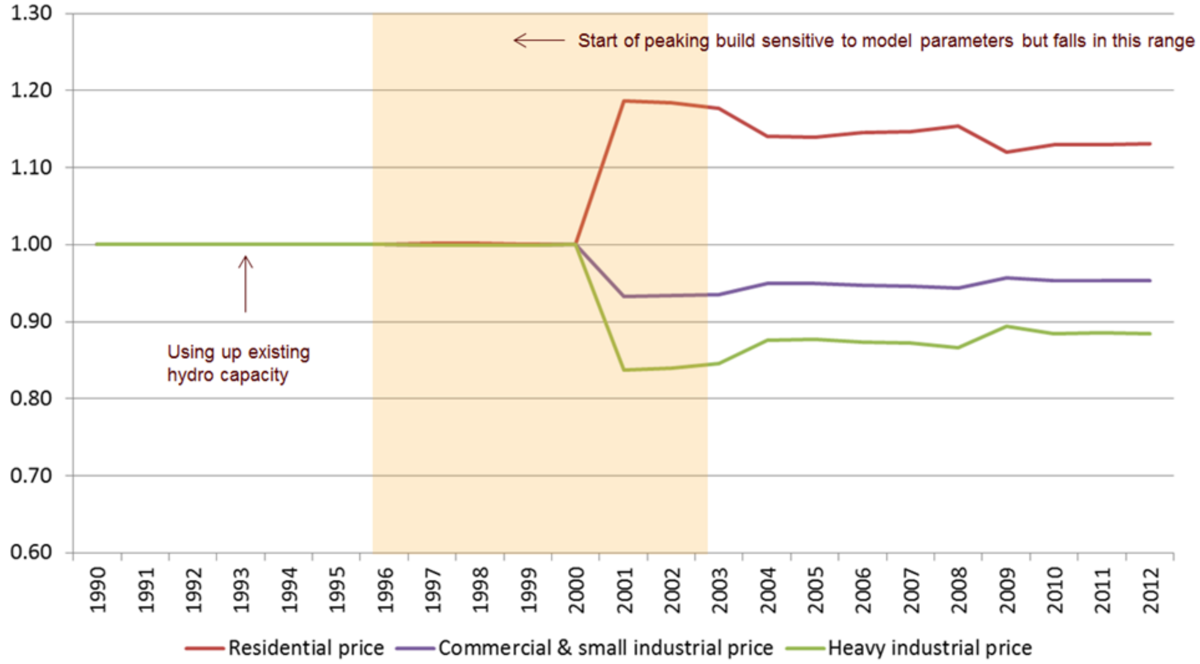
Based on the modelled generation costs presented in this paper, while the early- to mid-2000s saw retail charges increase relative to generating costs on average across all consumer types, at no time did average total charges exceed estimated costs. The cumulative under-recovery resulting from the negative margins shown above has been borne by a mix of taxpayers, and company shareholders. This analysis finds no evidence of windfall gains over historical generation costs accruing to generators or retailers.

Average generating costs have gradually reduced since the 1980s, and then increased again since the early 2000s, mainly as a result of increasing fuel costs. There have also been recent, lesser, impacts on total consumer retail charges associated with the increase in GST in 2010, and increases in transmission charges.

Different types of consumers cost more to serve than others. Demand that is more ‘peaky’ in nature, such as residential demand, is more expensive to supply than demand that is more constant, such as industrial load.

The Authority has estimated the cost of supplying different consumer types using an optimisation model designed to identify the cost of the additional generation that is required to supply additional demand. The following chart shows the estimated cost ratio of supplying residential demand, commercial/industrial demand, and heavy industrial demand, compared to an ‘average’ industry demand profile.

Figure 2 Cost of additional generating capacity for different consumer types relative to the system-wide average



Source: Electricity Authority

There is no difference in the cost ratio between the consumer types prior to around 2000, due to excess hydro-generation capacity prior to that, resulting in the marginal cost of serving additional demand being the same across all consumer types. Once that excess capacity was used up, the different nature of the demand associated with each consumer type results in different marginal costs to supply.

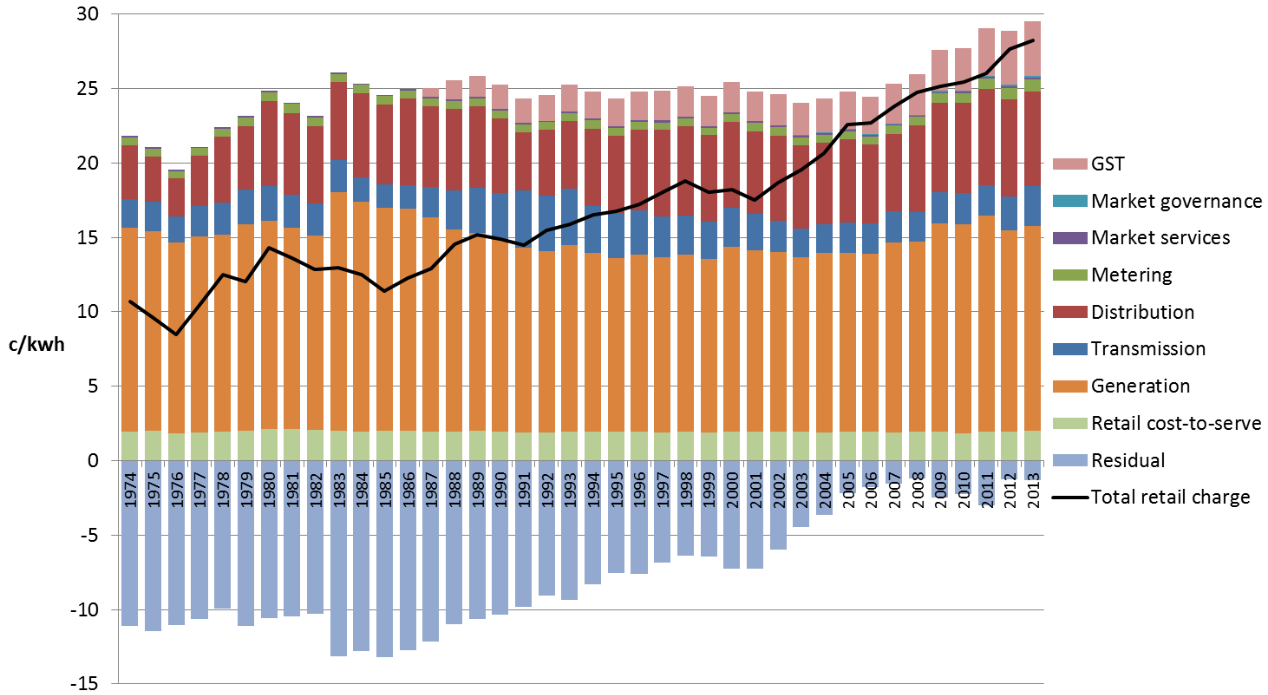
While the modelling assumptions make it appear as though there was no difference in the cost of serving different consumer types prior to 2000, peaking generation existed prior to that point, with some of it in the form of hydro generation. Determining the correct allocation of generating costs to different consumer types prior to the introduction of the electricity market is difficult as it is unclear whether the excess capacity of some hydro plants was intended to serve peak demand or to address production constraints.

In this analysis the Authority has decided to adopt a single cost ratio for the different consumer types, and project that back through the entire modelled period to reflect the higher cost of serving peaky load.

An adjustment has also been made to the ratios applying to each consumer type to reflect the additional costs arising from distribution line losses associated with supplying consumers connected to local distribution systems.

Applying the combined profile and losses ratios to the average generating costs identified using historical data produces the following breakdown of costs for each of the four modelled consumer types.

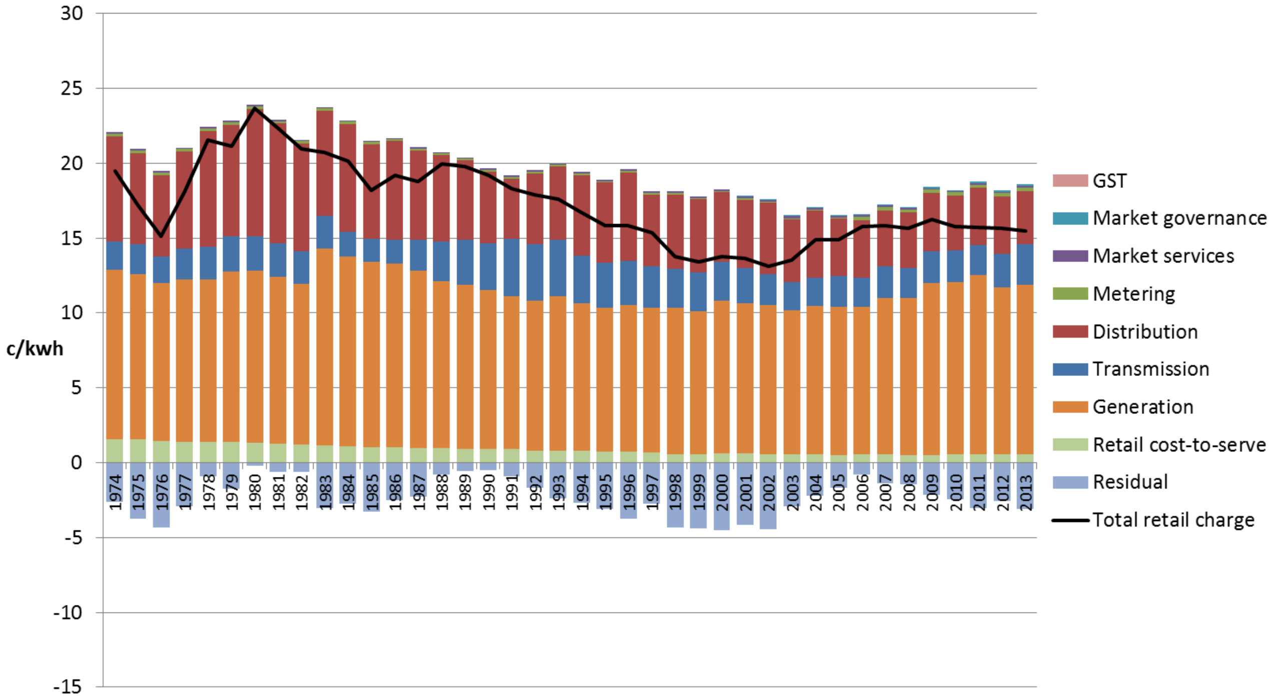
Figure 3 **Residential cost components**



Source: Electricity Authority

Real $2013

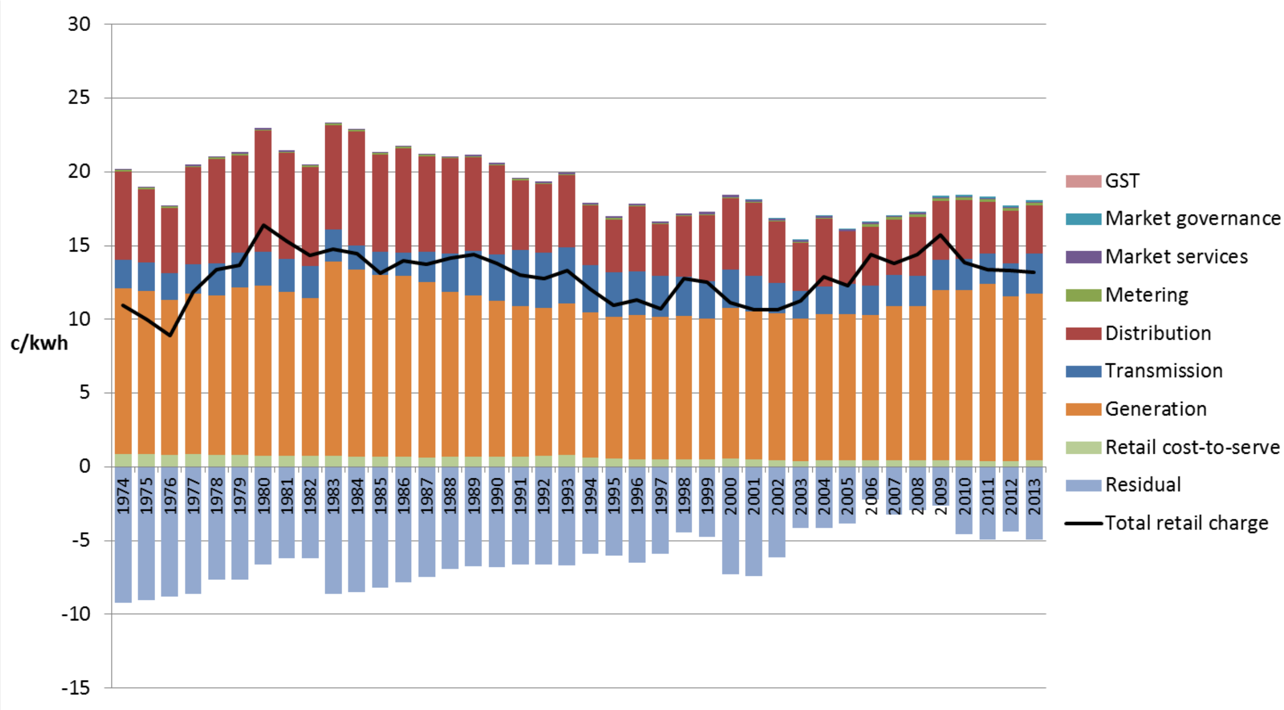
Figure 4 Commercial cost components



Source: Electricity Authority

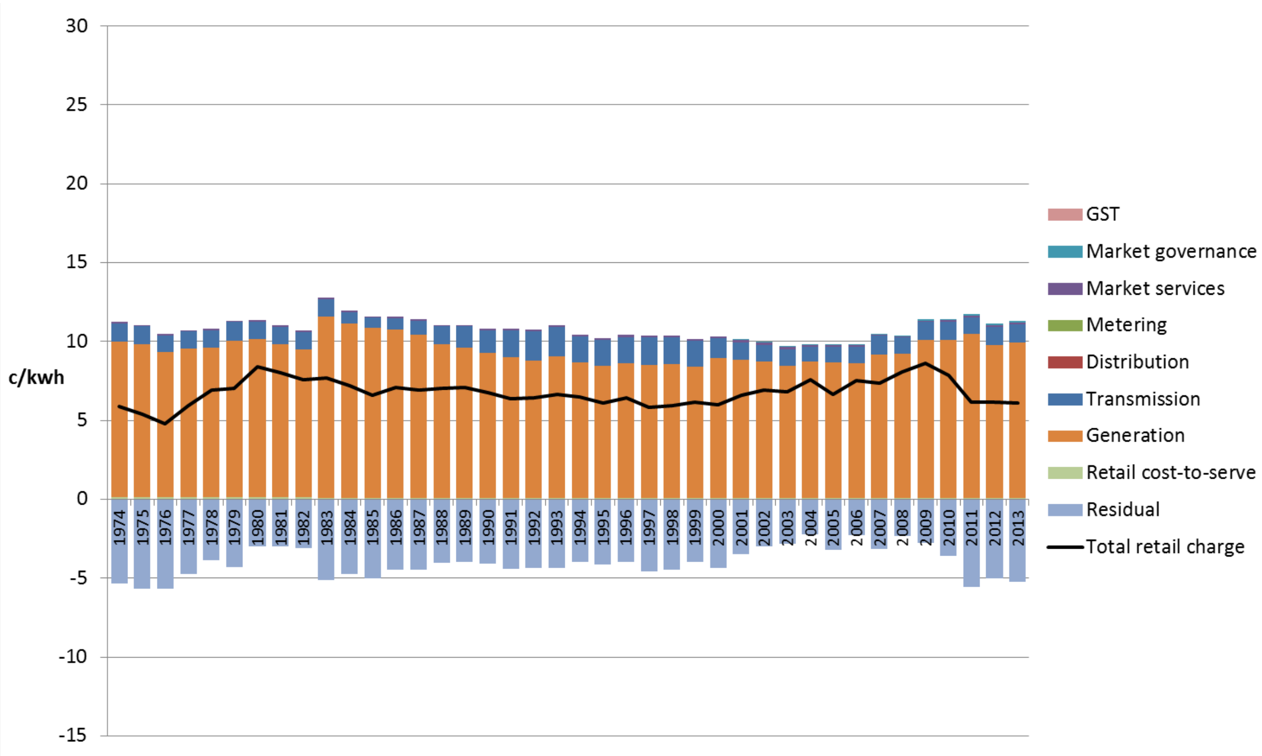
Real $2013

Figure 5 Industrial cost components



Source: Electricity Authority Real $2013

Figure 6 Heavy industrial cost components



Source: Electricity Authority Real $2013

The allocation of costs prior to the establishment of the electricity market is fraught with difficulty, as in practice there was no clear linkage between the prices charged to individual consumers and the underlying cost of supplying them with electricity. There is evidence of significant cross-subsidisation between consumer groups in the past. Commercial consumers are the only group that paid close to the modelled average cost of electricity supply between the 1970s and 1990s, while other consumers paid well under the cost of supply. It wasn't until the late-1990s that the margin between actual retail prices and the estimated total cost to supply commercial consumers started to bear some resemblance to the margins faced by other consumer types (shown as the light blue 'Residual' in the charts above).

More recently, the modelling suggests that residential consumers are currently paying close to the total cost to serve them based on historical cost, while other consumers are paying less than total cost.

The Authority conjectures that the transition to a competitive electricity market may have forced industry participants to more clearly relate prices charged to consumers to the cost of serving them, as not doing so would allow competitors to 'cherry-pick' consumers that are effectively over-charged.

It should be recognised that there are aspects associated with serving different customer types that are not reflected in the modelled costs and resulting residual margins shown above. The difference in margins for each consumer type does not reflect the different risks associated with serving different consumer types for example. Some consumer types more actively manage their exposure to movements in wholesale electricity prices than others, through hedging and demand response. This would be expected to influence the residual margins for industrial and heavy industrial consumers in particular, as the costs associated with risk management are incurred directly by the organisations undertaking them rather than by the retailers.

While the difference between the amount paid by heavy industrial consumers and the cost to serve them appears to be greater than other consumer types, the amount they are paying remains above the estimated short-run marginal cost of generation. This means that heavy industrial retail prices are still 'efficient' in the sense that they cover the short-run marginal costs of generating, while not over-recovering total costs.

The residual margin paid by residential consumers relative to other consumers indicates there may be scope for improvement in the residential retail market. Residential consumers *as a whole* do not appear to be achieving the same reduction in retail margins as other consumer types. However, anecdotal evidence suggests that residential consumers are often receiving significant price reductions when they 'shop around' for lower prices or when retailers approach them to switch to them. Not all these discounts are captured in the MBIE data used for this analysis.

The Authority plans to carry out further additional analysis work to improve its modelling of electricity industry costs, and to work with MBIE on expanding the scope of available consumer pricing data.

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1 Introduction

1.1 Retail electricity prices paid by residential, commercial, and industrial consumers have increased by an average of 4 per cent per annum since 1996.[1] The rate of increase has generally outpaced inflation, and has drawn criticism from a number of quarters. A number of explanations have been advanced about the underlying causes of the increase.

1.2 This paper explores how the costs incurred in the various parts of the electricity industry have changed since the early 1970s, and contrasts those cost changes with the changes in retail prices experienced by consumers.

2 Electricity industry reform since the 1970s

2.1 There have been fundamental changes to the structure of the electricity industry since the 1970s. Many of the key changes happened when wide-sweeping changes were being implemented across many aspects of the New Zealand economy. The economic reforms implemented from the mid-1980s included changes to tax-structures, financial markets, labour markets, public sector organisation ownership and management, producer subsidies, and trade tariffs and licensing.

Generation and transmission

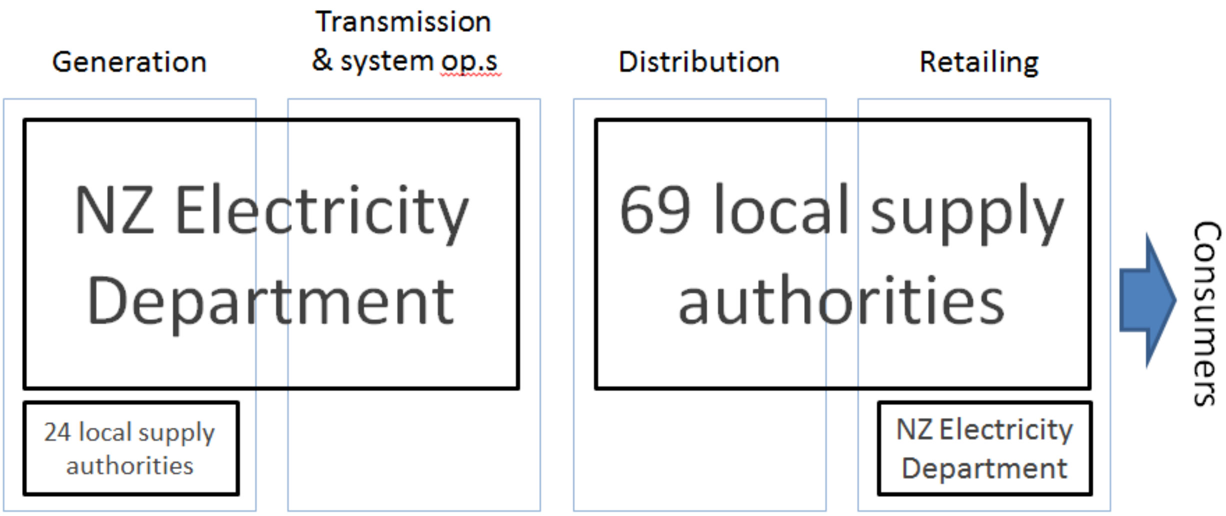
2.2 In the early 1970s, 97% of New Zealand's generating capacity[2] was owned and operated by the New Zealand Electricity Department (NZED). The NZED also maintained the high voltage transmission system, acted as the grid operator, and sold electricity directly to a few large customers.

2.3 Local distribution systems and the retailing of electricity to users were managed by 69 local supply authorities. The authorities were a mix of local bodies known as electric power boards (EPBs), and bodies run by territorial authorities and in two cases the Crown. The local supply authorities also owned and operated most of the non-NZED generating plant.

[1] Ministry of Economic Development 2012 Energy Data File. Based on nominal total sales and consumption for the year ending March 1996 and 2011. Excludes GST.

[2] Annual Statistics in Relation to Electric Power Development and Operation Year Ended 31 March 1973. Table VI - Capacity of Generating Plant.

Figure 7 Industry structure in 1972



Source: Electricity Authority

2.4 In April 1987 the NZED[3] was reformed into the Electricity Corporation of New Zealand (ECNZ). ECNZ operated as a State Owned Enterprise (SOE), originally as 'Electricorp'.

2.5 In 1994 ECNZ's transmission and system operation activities, which had been operating as a subsidiary within ECNZ since 1988, were separated out into a new SOE as Transpower New Zealand Limited (Transpower).

2.6 In 1996 part of ECNZ's generating activities were split off into a separate business as Contact Energy Limited (Contact).

2.7 In 1999 Contact was privatised, and the rest of ECNZ was split into three separate SOEs: Meridian Energy Limited (Meridian), Mighty River Power Limited (MRPL), and Genesis Energy Limited (Genesis).

2.8 While there were only a few significantly-sized independently owned generators operating prior to 1996 (co-generation plant had been installed at the Glenbrook steel mill and a number of dairy factories), the number of companies owning large generating plant has increased over time. There are now 16 separate companies and joint ventures that own plant over 10MW in size. There are approximately a further 50 companies that own plant over 0.1MW in size.

Distribution and retailing

2.9 In 1992 the Energy Companies Act 1992 came into effect and required local supply authorities to operate as commercial companies. In 1999 the distribution lines and retailing businesses were separated, with those organisations

[3] NZED had previously been renamed to 'New Zealand Electricity' in 1973 and had become the Electricity Division of the Ministry of Energy in 1978.

undertaking both activities having to sell one or the other. The retailing businesses were mainly purchased by the new generating businesses, although TransAlta New Zealand operated for a short time as a separate retailing company[4] before being sold to Natural Gas Corporation (NGC) in 2000 along with the generating assets it had acquired. The TransAlta customer base was ultimately sold to Genesis and Meridian in 2001.

2.10 The generating activities of the local supply authorities were also separated out from the local lines activities in 1999. TrustPower Limited, which had originally been formed from the generation business of the Tauranga Electric Power Board in 1993, purchased many of the larger locally-owned plants.

2.11 The line businesses went through two main periods of amalgamation. By the late 1980s the number of local supply authorities had been reduced to 52. Following the split of the authorities into separate lines and retailing businesses, many of the lines businesses were also sold. Subsequent mergers have resulted in the total number of local line companies reducing to 28 by 2013.

2.12 In 1999 embedded network operators were allowed to aggregate and manage lines and consumer meter connection points within existing line company areas. Typically this occurs within shopping malls or apartment blocks. There are now approximately 135 embedded networks in New Zealand being operated by 43 separate owners.

2.13 The retail side of the electricity market has seen an increase in participants over recent years compared to when the retailing businesses were first sold to the major generators. As at December 2012 there were 14 separate companies acting as retailers in New Zealand, trading as 22 different brands, although some of the smaller retailers are only active in limited geographical areas.

Electricity market and regulation

2.14 In 1993 the Electricity Market Company was established, and in October 1996 the wholesale electricity market started trading, although interim trading arrangements had been in place since February 1996 to allow Contact and ECNZ to compete.

2.15 In 2001 a group of industry participants established the Office of the Electricity Complaints Commissioner as a voluntary body to assist consumers to resolve complaints about lines or retail companies. In 2005 the organisation expanded its functions to become the Office of the Electricity and Gas Complaints Commissioner.

2.16 In 2003 the Electricity Commission was established as the regulator for the New Zealand electricity industry. In 2010 the Commission was replaced by the Authority, and the Commission's transmission approval functions were shifted to

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[4] TransAlta had previously purchased combined lines/retail businesses and subsequently sold the lines components when the business split was required.

the Commerce Commission and the Ministry of Economic Development (now MBIE). The Commission's energy efficiency functions were moved to the Energy Efficiency and Conservation Authority (EECA).

2.17 The requirements of running the electricity market also saw the establishment of a number of functions within companies that were ultimately funded under service provider contracts by the Electricity Commission and later by the Authority. These include the reconciliation manager, pricing manager, clearing manager, and wholesale information trading system functions that are primarily concerned with the day-to-day running and monthly settlement of the market.

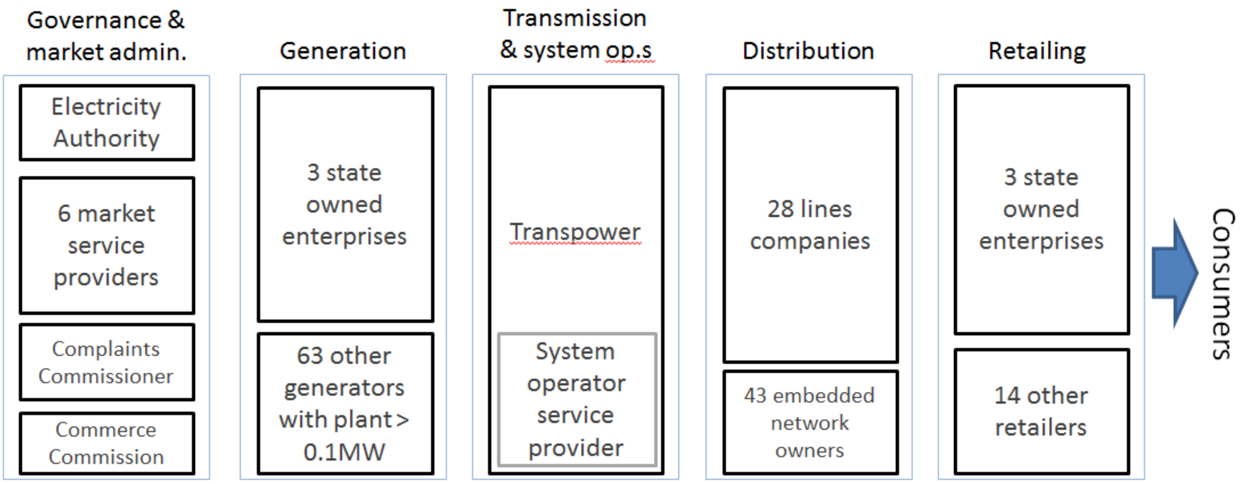
2.18 In 1999 a registry manager function was established to facilitate the switching of customers between retailers.

2.19 The real-time operation of the electricity system, involving the scheduling and dispatch of generation to meet demand and management of reserves and power quality, is carried out by the system operator. The system operator function was transferred to Transpower from ECNZ in 1994 with the transmission system business. It is now separately funded by the Authority under a service provider agreement.

2.20 In 2012 a Financial Transmission Rights (FTR) manager service provider function was established to administer the new FTR financial instruments that started to trade in June 2013.

2.21 With the exception of the system operator functions, all service provider agreements are potentially open to competitive tender when they come up for renewal.

Figure 8 Industry structure in 2013



Source: Electricity Authority

2.22 There are a wide range of other companies involved in the industry that do not directly feature above. Much of the maintenance and construction activity previously carried out by the Electricity Department and local supply authorities is now undertaken by contracted third-party providers. The development of secondary electricity market products and services (such as hedging, and the aggregation of interruptible load) has resulted in a number of financial institutions and other companies participating in the market in addition to the directly-involved industry organisations.

Other policy changes directly affecting costs

2.23 While many of the wider economic reforms implemented since the mid-1980s have impacted on the electricity industry to some extent, a few key changes had direct implications for electricity suppliers and consumers.

2.24 Goods and Services Tax (GST) was introduced in October 1986 at a rate of 10%, replacing a number of existing sales taxes. Personal income tax rates were lowered at the same time, so the impact of GST was offset, albeit with different individual net effects depending on income and expenditure patterns. GST was raised to 12.5% in July 1989 and to 15% in October 2010. Both increases were matched by changes in personal income tax rates (although only in the top tax-bracket in the case of the 1989 increase).

2.25 Company tax rates were reduced. In 1972 the company tax rate was 48%. This dropped to 28% briefly in 1988 and back up to 33% in 1989. The rate was later reduced to 30% in 2008 and back to 28% in 2010.

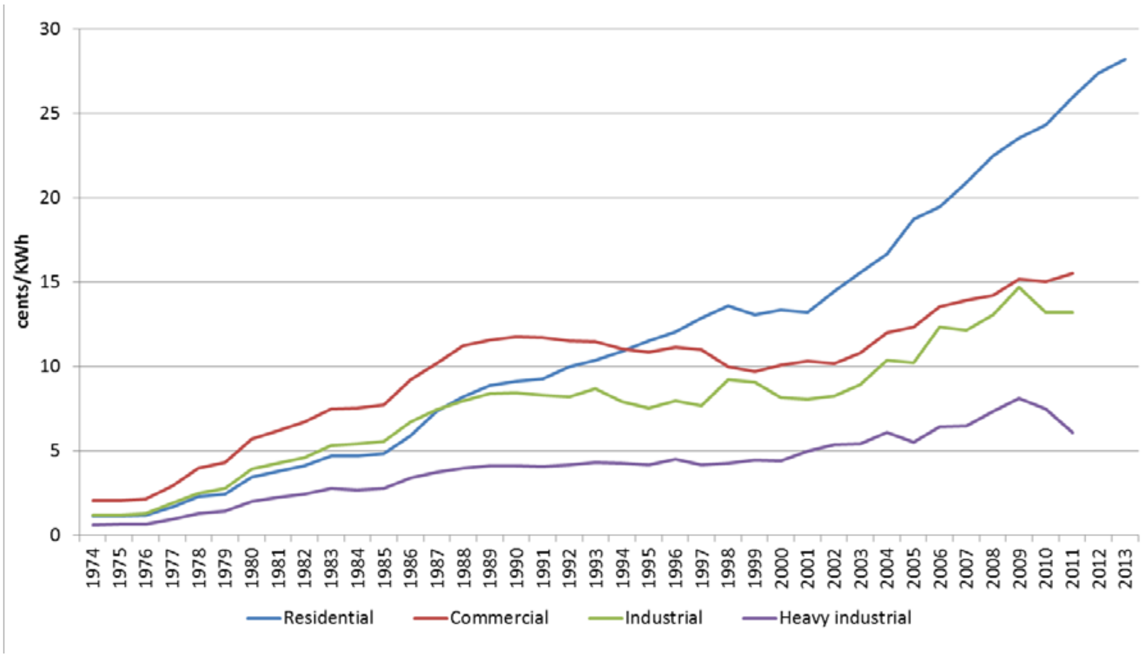
2.26 The Emission Training Scheme (ETS) was introduced in 2008 to help meet New Zealand's Kyoto Protocol obligations, with later amendments in 2009 and 2012. The 'Stationary Energy' sector, encompassing electricity generation, was initially required to surrender one emission 'unit' for every two tonnes of CO2 emitted (or other equivalent emissions) from July 2010. While the 1-for-2 rate was originally set to transition to a 1-for-1 rate in 2013, the 1-for-2 rate has now been extended until at least 2015. Generators can purchase emissions units from domestic and some overseas emission unit markets, or they can pay a fixed surrender price of $25/tonne. Since 2010 the market price of emission units has dropped significantly. New Zealand Units (NZUs) averaged about $20/tonne in the year-ending March 2010, dropping to approximately $4/tonne in the year ending March 2013 and about $2/tonne since then.

3 Retail electricity price movements since 1974

3.1 The following chart shows retail price movements for each major industry consumer group from 1974 to 2013 based on data published by MBIE.[5]

[5] Energy Data File March-year data published as the Ministry of Economic Development, combined with residential price data for March 2012 and March 2013 from MBIE quarterly electricity price surveys.

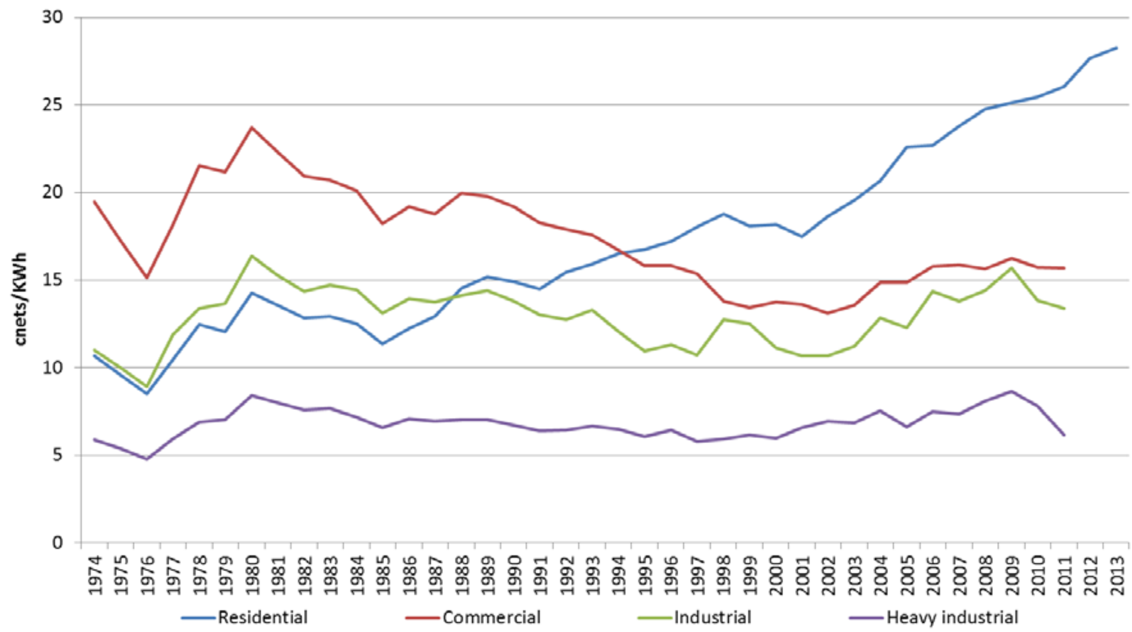
Figure 9 Retail price movements from 1974 to 2013



Source: MBIE

3.2 The above prices are shown in nominal terms (i.e. unadjusted for the effect of inflation). The following chart shows prices expressed in real terms (i.e. adjusted for inflation).

Figure 10 Retail price movements from 1974 to 2013 - Real 2013 dollars



Source: Electricity Authority Real $2013

3.3 It is immediately apparent that commercial prices have come down in real terms relative to residential prices, which have seen a significant increase since 1974.

3.4 It has been suggested in a number of forums that residential electricity prices were explicitly subsidised by commercial consumers prior to the industry reforms of the 1980s. Increases in real residential prices have been fairly steady since the mid-1980s, while commercial and industrial prices have only seen real increases since around 2001.

3.5 To understand what may be driving these changes it is necessary to explore the changes in costs across the industry over time. This is made somewhat more complex by the organisational changes discussed earlier.

4 Current industry costs

4.1 Because of the ownership structure in many areas of the electricity supply chain, reasonably transparent data is available detailing the costs of individual companies and their activities. The exception is the retailing and generation areas where the mixed public and private ownership and vertical integration of the main companies involved makes splitting the cost of their activities into separate functions more problematic.

Transmission

4.2 As noted earlier, Transpower is responsible for the management and operation of the high voltage national grid and operates as a government owned SOE. Its transmission line activities are subject to price and quality regulation by the Commerce Commission. The Commerce Commission sets total revenue limits for Transpower based on its approved asset base and expenditure, and a regulated rate-of-return. The methodology that Transpower must use to allocate its line business costs to other participants in the electricity industry is determined by the Authority. The current Transmission Pricing Methodology (TPM) requires Transpower to recover transmission costs from lines companies, direct connect customers, and generators.

4.3 Total recovery[6] for Transpower's transmission business was $624 million for the year ending March 2011. Of that amount, roughly 20% was recovered from generators, 10% from direct connect customers, and the remaining 70% from lines companies. Lines companies generally pass these costs onto retailers, who in turn recover them from their customers.

4.4 Revenue associated with transmission activities has increased over the past two years as a result of the construction of a number of major new interconnection assets, including the new Whakamaru to Auckland transmission line, and the HVDC Pole 3 project. Projected revenue for the year ending March 2013 was $807 million.

6 Transpower Transmission Pricing Revenue Requirement statements.

4.5 Transpower's system operation activities are funded by the Authority through a service provider agreement and are discussed further in the Market Services section below.

Distribution

4.6 Like Transpower, the various distribution lines businesses are subject to regulation by the Commerce Commission. Lines businesses are operated under a number of different ownership models, but as natural monopolies they are all required to publically disclose financial and operational information. Lines businesses that are not consumer-owned (about half of them) are subject to Commerce Commission price and quality controls.

4.7 The Authority publishes voluntary Pricing Principles. Lines businesses generally charge retailers, who then pass the costs on to consumers as part of their normal monthly bill. In one case consumers are billed directly by the lines business.

4.8 Total lines business recovery[7] was $1,913 million in the year ending March 2011.

Market governance

4.9 The Authority is responsible for facilitating and monitoring the New Zealand electricity market and administering the Electricity Industry Participation Code 2010. The Authority coordinates the service provider agreements used to manage the operation of the electricity system and wholesale electricity market (see Market Services below).

4.10 The costs of running the Authority are managed through the government appropriation system. Recovery of costs is through the Electricity Authority levy, where charges are allocated out to individual participants based on a number of activity indicators such as consumption or generation volumes.

4.11 The service provider agreements are a significant proportion of the Authority's costs. Of the $87 million levied in the year ending June 2012, $39 million was for the various service provider agreements, $13 million for Energy Efficiency Programmes undertaken by EECA, $10 million for the provision of dry-year reserve plant[8], $4 million for the retail customer switching fund, and $21 million for the administrative costs of running the Authority.[9]

4.12 Commerce Commission costs associated with the regulation of the electricity industry are funded through general taxation.

4.13 The Office of the Electricity and Gas Complaints Commissioner is funded by member companies covering a range of industry participants. Total recovery from participants was $2 million in the year ending March 2012.

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7 Commerce Commission Electricity Information Disclosure Database.

8 The Whirinaki generating station was sold to Contact Energy by the Crown in December 2011 after the requirement for the Authority to contract dry-year reserve was relaxed.

9 Electricity Authority 2011/2012 Annual Report.

Market services and system operation

4.14 The pricing manager, reconciliation manager, clearing manager, and Wholesale Information Trading System functions are all currently undertaken by NZX Limited, or their wholly owned subsidiary, under separate service provider agreements with the Authority. The costs of the agreements in the year ending June 2013 were $1.7 million, $1.3 million, $1.5 million and $1.6 million respectively.

4.15 The registry manager function, facilitating the switching of consumers between retailers, is currently carried out by Jade Software Corporation (NZ) Limited. The registry manager service provider cost for the year ending June 2012 was $0.5 million.

4.16 The FTR manager function is carried out by the Energy Market Services (EMS) division of Transpower. The budgeted service provider cost for the year ending June 2014 (the first full year of active trading) is $0.9 million.

4.17 Transpower has carried out the system operation functions since its separation from ECNZ in 1994. The system operator is managed as a separate division within Transpower. The system operator service provider agreement cost for the year ending June 2012 was $32 million.

Metering

4.18 In the 1970s, non-grid connected meters were owned and operated by the local supply authorities. When the lines and retail businesses were separated in 1999, initial ownership of meters varied, in some cases being vested in the retail side of the businesses and in other cases the lines side.

4.19 Since 1999, independent metering providers have gradually taken over the ownership and operation of both residential and commercial/industrial meters, to the point where nearly all meters are now owned by such organisations. These metering providers have in turn been purchased by other industry participants, but are still operated as separate companies.

4.20 In most cases retailers have contracts with the metering providers, and recover the metering costs from consumers as part of their normal monthly bills. In a few cases commercial and industrial customers are directly billed by the metering provider.

4.21 For the purposes of this analysis, metering costs have been estimated by the Authority based on the number of meters, and an estimated cost per meter per year. Per unit annual costs are estimated at $45 for analogue residential meters, $85 for ‘smart’ meters and non-half hour commercial/industrial meters, and $1020 ($85 per month) for commercial/industrial half hour meters.

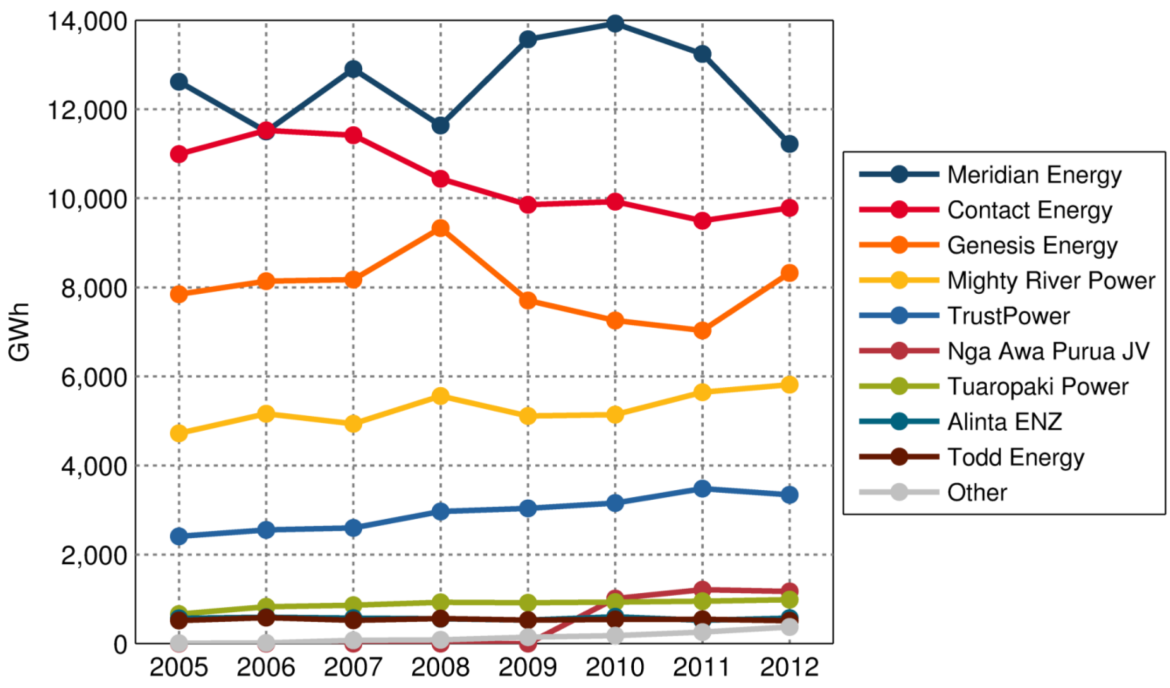
4.22 Total metering costs for the year ending March 2012 were estimated at approximately $140 million.

Generation and retail

4.23 Splitting generation and retail costs is complex because of the vertical integration of the major generator/retailers, and the annual variation in the underlying drivers of costs such as hydrology, and consequently thermal fuel use.

4.24 There are currently 16 generators operating plant greater than 10MW in size. The following chart shows the relative market share of the major generators in New Zealand since 2005.

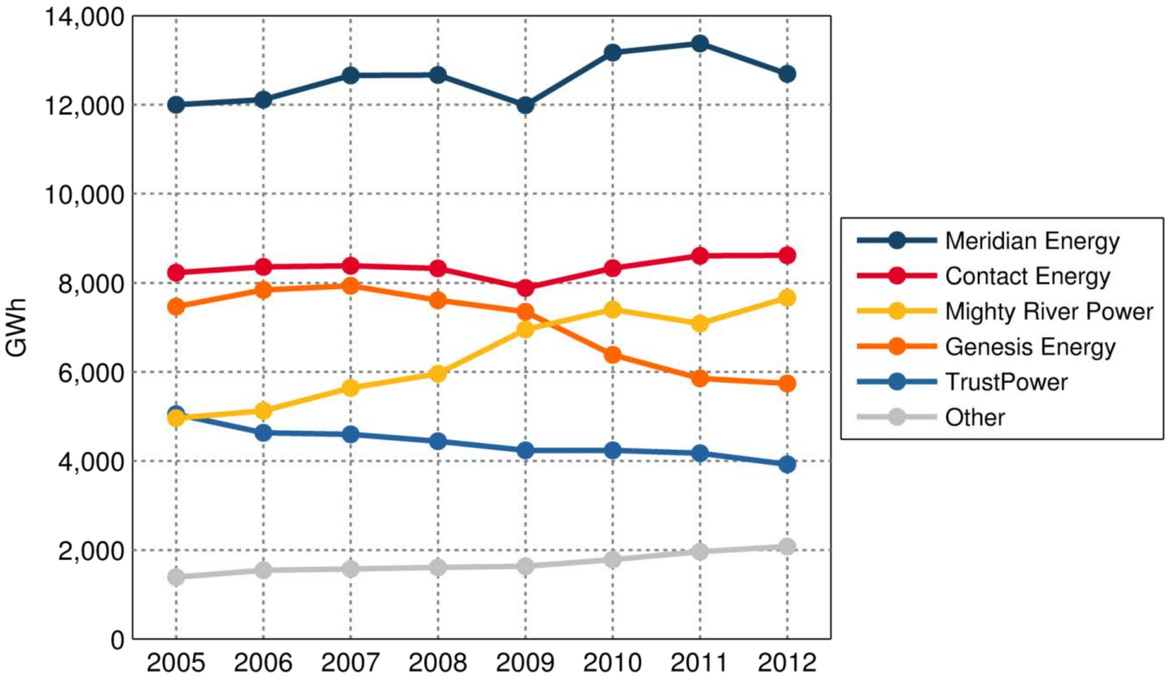
Figure 11 Generator wholesale market sales



Source: Electricity Authority

4.25 The following chart shows purchases by retailers on the wholesale market.

Figure 12 Retailer wholesale market purchases



Source: Electricity Authority

4.26 While some of the major generator/retailers above have chosen to maintain either a net-generation or net-retail position at times, on the whole the individual generator/retailers attempt to match demand and generation as a natural hedge against movements in wholesale market prices.

4.27 The Authority has used two approaches to estimate the cost of generation; a market based approach, and an approach using the historical cost of building and operating generating plant.

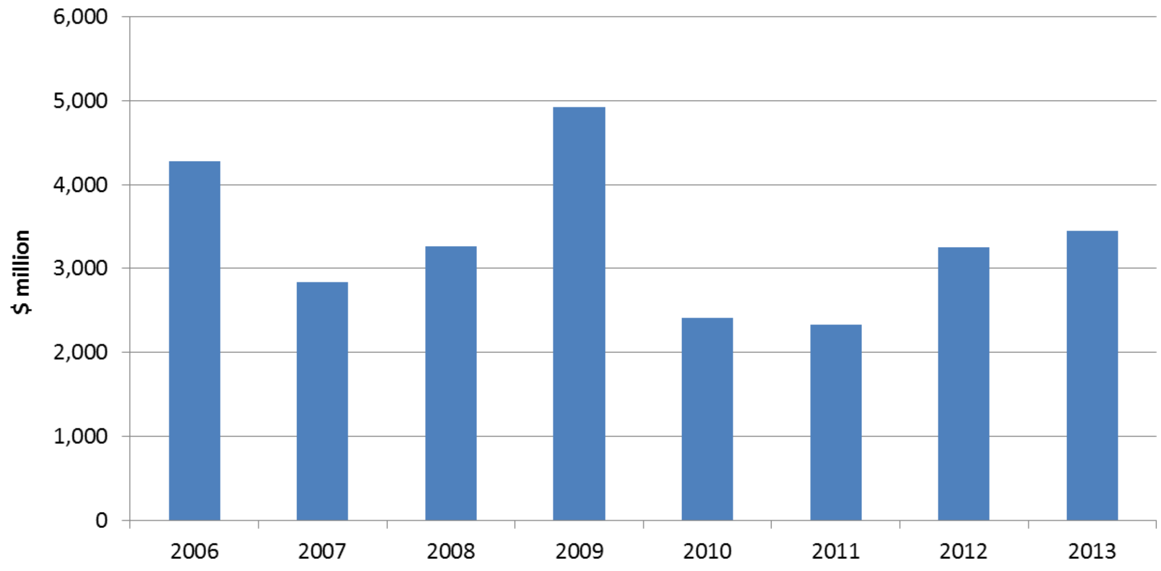
5 Market based estimate of generation costs

5.1 The vertical integration of the generator/retailers, and the operation of the hedge market, mean that the total revenue traded across the wholesale market is not necessarily an accurate measure of the total revenue received by the 'generator' businesses to offset costs (putting aside any impacts associated with the FTR market which has been operating for only a few months). The prices seen in the wholesale market may only impact in net terms on a limited proportion of a generator/retailer's total portfolio, and hedge market trades can occur between parties within the same generator/retailer.

5.2 Accepting the limitations of wholesale market revenue as an indicator of generation costs, it is still useful to explore how market revenue has varied from year to year relative to retail customer charges. Wholesale market prices respond to conditions such as periods of low hydro inflows and other supply constraints, which push up thermal fuel use and therefore underlying generation costs.

5.3 The following chart shows total annual wholesale market revenue from 2006, calculated by multiplying consumption volumes measured at each grid point of connection by the associated wholesale market price. Figures are for the year ended March, and are converted to 2013 dollars using the Consumer Price Index (CPI).[10]

Figure 13 Total annual wholesale market revenue



Source: Electricity Authority Real $2013

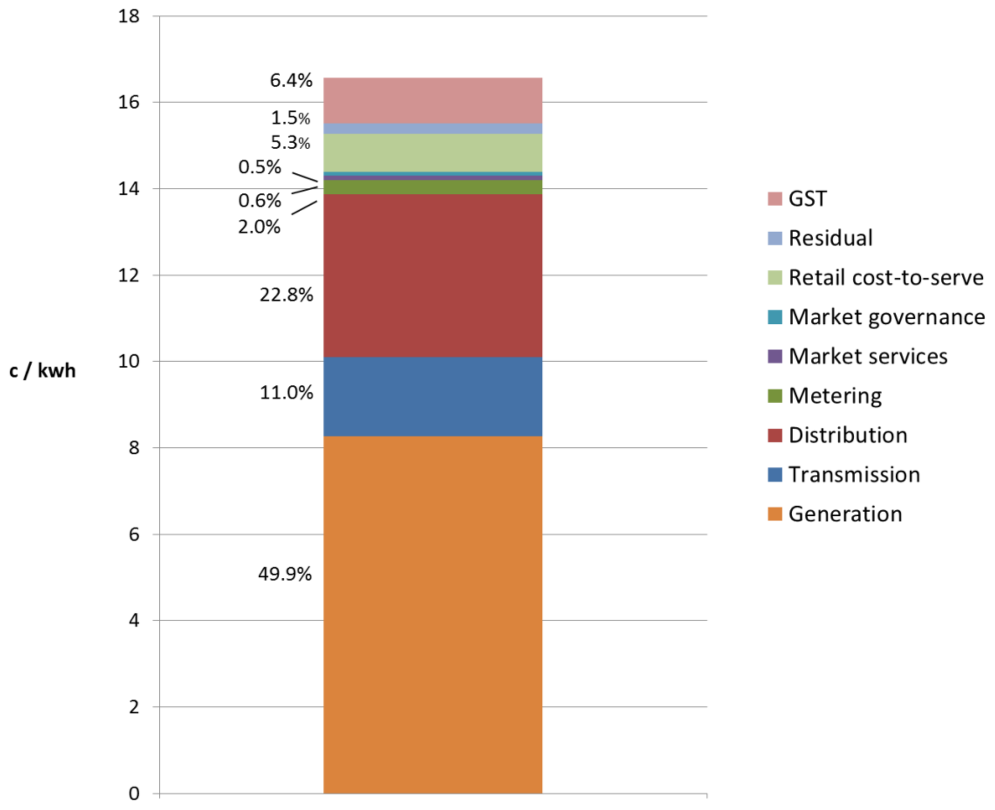
5.4 The winters of 2005 and 2008 had relatively low hydro inflows, with a resulting increase in average market prices (showing in the 2006 and 2009 March years). Although the winter of 2012 saw the lowest inflows over the first half of the year since records began in 1932, the impact on wholesale prices was more muted as a result of effective water management by the generators and high inflows later in the year.

5.5 Using a simple average of wholesale market revenue between April 2005 and March 2013 as an estimate for generation costs yields a stack showing the makeup of retail charges averaged across all consumers for the year ended March 2011 below (values are in real 2013 dollars).

[10] Adjusted to exclude the impact of the October 2010 increase in GST

Figure 14 Makeup of retail charges for the year ended March 2011

Averaged across all consumers



Source: Electricity Authority Real $2013

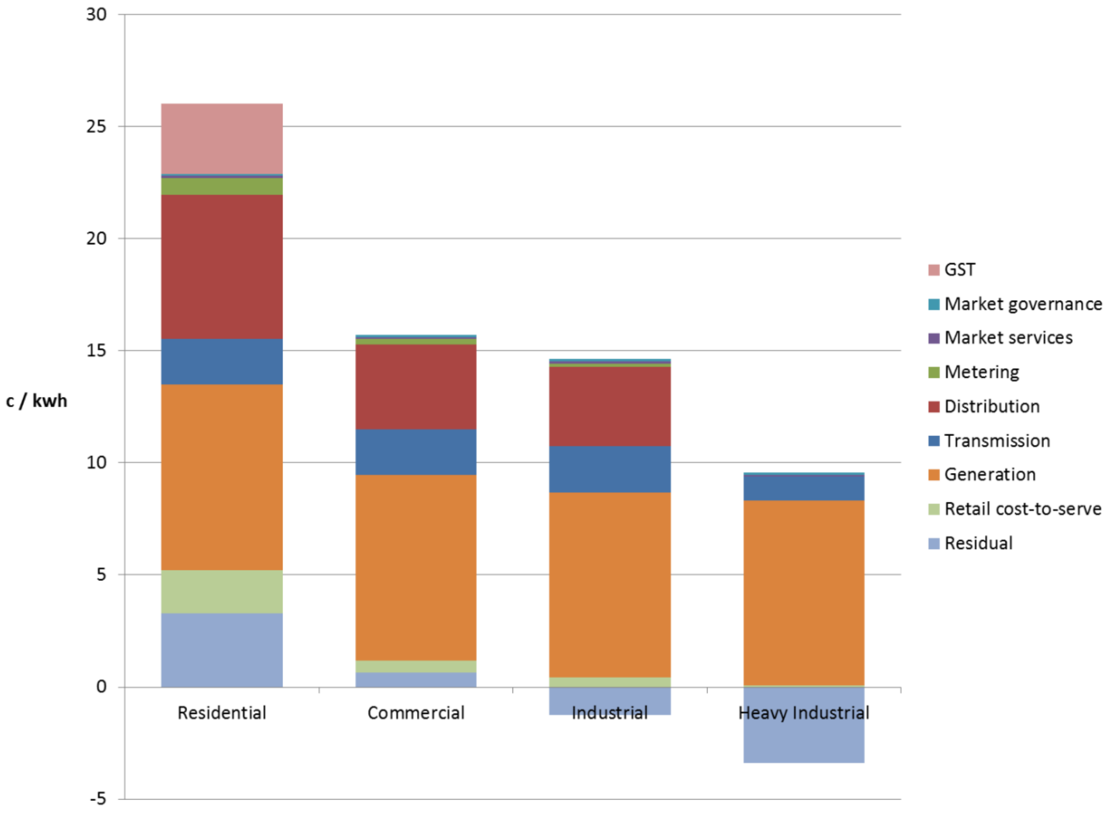
5.6 The administrative cost of managing retail customers has been estimated by the Authority and shows in the above chart as 'retail cost-to-serve'. The 'residual' shown in light-blue above represents the difference between the estimated total cost of providing electricity to consumers, and total consumer retail charges. If the residual is positive, as it is in the above chart, consumers are paying more than the total estimated cost. If the residual is negative, consumers are paying less than total cost. The residual is not associated with any cost type in particular. It only measures the difference between retail charges and estimated costs across the entire industry supply chain.

5.7 GST is assumed to impact only on residential customers (i.e. commercial and industrial consumers would normally claim back GST payments as part of the rebate system).

5.8 The following chart shows the estimated breakdown for different consumer types (based on MBIE data and cost data above) using the same simple market-revenue based approach, with generation costs in this chart being treated as an average cost across all consumers. Retail cost-to-serve and the residual margin are shown at the bottom of the stacks to make the comparison between margins across the different consumer types easier.

Figure 15 Estimated breakdown for different consumer types

Generation costs in this chart are treated as an average cost across all consumers



Source: Electricity Authority Real $2013

5.9 Based on a simple average wholesale market revenue approach, industrial and heavy industrial users appear to have paid less than the average cost of supplying electricity (reflected in the negative residual costs), and residential and commercial customers more than cost. Aside from the points noted above about the problems with using wholesale market revenue as a proxy for generation costs, the cost of generation required to serve different customers varies because of differences in the costs of meeting different demand profiles. In general, peaky demand (such as residential demand) requires the support of more expensive peaking generation, relative to a flat demand profile that can be served using base-load generation.

5.10 Differences in the generating cost of meeting different load types are covered in more detail in Section 8 below.

5.11 Other costs are also influenced by the flatter nature of the heavy industrial load. Transmission costs are generally lower on a per-unit basis than for the other consumer types. The higher average energy use by the non-residential consumers also results in lower per-unit metering and distribution costs compared to residential consumers.

6 Estimated historical cost of generation

6.1 To provide a better picture of actual generating costs compared to retail prices, the Authority has used an historical cost-based approach that estimates annual generation costs across the different organisational structures that existed between the 1970s and the present. Published information on generating plant capital expenditure and operational costs has been used to estimate a Long Run Marginal Cost (LRMC) for each plant, which has then been used to estimate an average total system generation cost in each year. This approach does not attempt to capture year-on-year variations in costs associated with hydrology and other operating constraints.

6.2 Prior to the establishment of ECNZ in 1987, detailed NZED data was released as part of the Annual Statistics in Relation to Electric Power Development and Operation publication. While the agency responsible for publishing the document changed over time, the report structure remained fairly constant from the 1930s through to the 1980s. Capital expenditure on individual plant was reported on a cash-accounting basis so it is possible to establish expenditure cashflows and convert them to a 2013 dollar equivalent.[11]

6.3 Post-ECNZ, plant capital costs have been obtained from a mix of published documents, press releases, and in some cases have been estimated using generic capital costs for different generating technologies.

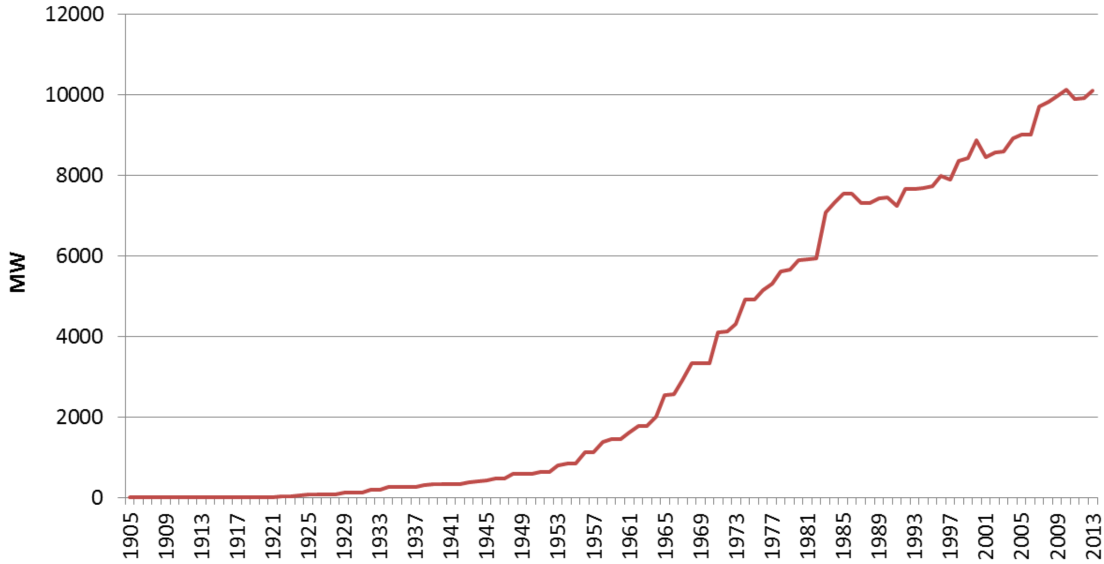
6.4 Operating costs have been based on figures published as part of the grid planning assumptions work carried out by the Electricity Commission, and later MBIE.

6.5 Appendix A contains a schedule of assumed capital and operating costs, and capacity assumptions used in this analysis.

6.6 The following chart shows total installed generating capacity in New Zealand since 1905.

[11] CPI, adjusted to exclude the impact of GST, has been used to convert all costs to 2013 dollars.

Figure 16 Total installed generating capacity



Source: Electricity Authority

6.7 Calculation of a LRMC for each plant has been simplified by assuming a constant average annual output rate for each plant across its lifetime. In reality, most thermal plant has gradually reduced its utilisation over time as it has aged and been displaced by more efficient plant.[12]

6.8 Changes in operating costs have been dealt with by splitting the LRMC into a fixed component capturing capital and fixed operating and maintenance costs, and a variable component covering variable operating and maintenance costs. The variable LRMC component is scaled from year to year in response to factors such as changing fuel costs and carbon charges. Historical fuel prices have been based on information from the MBIE Energy Data File publications. Carbon costs have been based on historical New Zealand Unit prices, also obtained from MBIE.

6.9 The fixed LRMC component is based on a standard maximum asset life for each plant (50 years for hydro plant for example). The fixed LRMC values are applied across the entire operating life of the plant, which in the case of some hydro plant is much longer than the standard asset life. This approach spreads the capital cost of the plant across its full economic life. Using standard asset lives instead of the full economic life has only a minimal impact on LRMC values because of the cumulative effect of discounting costs in years greater than the standard asset life.

6.10 LRMC calculations exclude tax, to maintain consistency between the different organisation types building generation over the modelled period. The discount

12 An option for additional modelling in the future is to dynamically adjust the LRMC over time in response to projected remaining utilisation.

rate used in the LRMC calculation assumes a constant Weighted Average Cost of Capital (WACC) of 10.1% (pre-tax real). The analysis is reasonably sensitive to the discount rate used. The 10.1% value was recommended by the New Zealand Institute of Economic Research (NZIER) based on a number of derived parameters and covers the entire modelled period.[13]

6.11 Estimated LRMC values have been calculated for plant back to 1907 because of the impact of earlier plant build on the period being examined. Most large hydro plant built over the 20th century is still running in some form, albeit refurbished or expanded in many cases. Major plant refurbishment and expansions have been treated as separate generating plant in the model.

6.12 Because the LRMC calculated using this approach is based on the potential output of plant, the resulting average system cost shown in the following charts is lower than the average per-unit cost of generating power based on actual plant output.

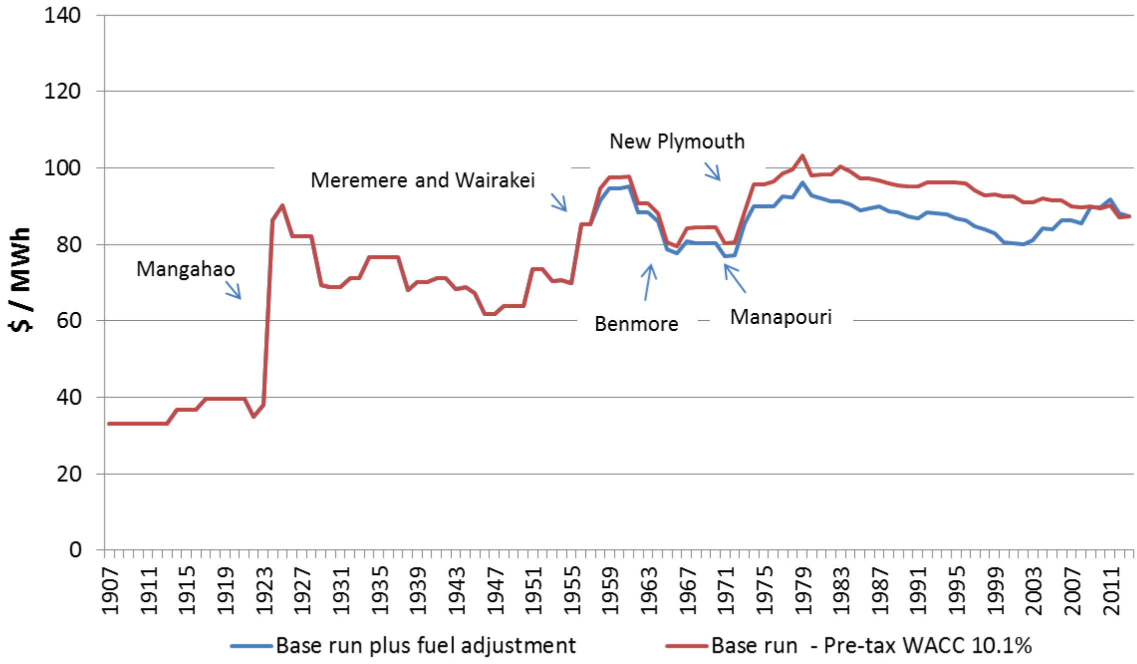
6.13 A number of model scenarios were used to capture the changes in industry structure and costs over time. They are also useful for illustrating the impact of some of the key model assumptions below.

6.14 In the base scenario, the estimated average system cost reflects all historical capital expenditure. Fuel costs are assumed at their 2013 level across the entire modelled period.

6.15 The following chart shows estimated total generation costs between 1907 and 2013 expressed in $/MWh for the base scenario in red. The impact of adjusting plant costs to reflect historical changes in fuel costs and carbon charges relative to their 2013 values is shown in blue.

[13] A letter outlining the NZIER analysis and recommended WACC value is attached as Appendix B.

Figure 17 Modelled historical generation costs and the impact of fuel price changes



Source: Electricity Authority Real $2013

6.16 The construction of individual plant had a more significant impact on average cost when the installed base was fairly small, as evidenced by the sudden jump in cost with the build of the Mangahao plant in 1924, and to a lesser extent the construction of Meremere, Wairakei and New Plymouth (the impact of the two thermal plants is better reflected in the fuel-adjustment scenario shown in blue).

6.17 The base scenario shown in red above suggests that, all else being equal, the average per unit cost of generation has gradually reduced in real terms since the establishment of ECNZ in the 1980s.

6.18 Changing fuel costs have significantly impacted on total system costs over time, more so as the total amount of thermal plant has increased. The difference between average LRMC costs based on constant fuel costs (in red) and LRMC costs reflecting fuel cost movements (in blue) illustrates the impact of the increase in fuel costs since 2000.

6.19 The Authority explored a number of other scenarios as part of the analysis, including alternative WACC assumptions and assumptions around asset revaluations pre- and post-corporatisation. While the results of the sensitivities run by the Authority are not presented here, they are included in the published models accompanying this report.

7 Estimated generation costs compared to retail charges since 1974

7.1 Data published by MBIE (as the Ministry of Economic Development and previously the Ministry of Energy) and a mix of other sources[14] has been used to estimate the cost of the individual components of retail charges back to 1974.

7.2 The MBIE data splits total reported retail revenue received from electricity consumers between lines 'costs' (capturing transmission and distribution costs), and energy 'costs' (assumed here to capture all other costs).[15] Revenue is further split between consumer types. While there are some apparent categorisation issues with the breakdown of revenue and consumption between consumer types in the mid 1990's and early 2000's, these do not appear to have had any material impact on the resulting analysis. MBIE is currently investigating a number of issues relating to the recent supply of data published in the Energy Data File. Initial indications are that the supplied data may not fully account for residential customer discounting, and so may overstate retail prices over the past few years. As this analysis relies on these figures, the results below should be treated as reflecting some overstatement of residential retail prices.

7.3 Historical distribution costs have been estimated based on the difference between total lines costs, and an estimate of transmission costs drawn from annual report data. While these have been treated as lines 'costs' for the purpose of this analysis, there are likely to be differences between reported revenue and actual costs. This is particularly true prior to 1996 where an element of cross-subsidisation may have existed between consumer types. The split of lines and energy costs has been estimated prior to 1996 based on post-1996 revenue data.

7.4 To maintain consistency between the historical-cost based approach used to estimate the cost of generation, and the transmission and distribution costs, the lines-related costs have been scaled up slightly. This one-off adjustment captures historical expenditure on distribution and transmission assets that were subsequently 'optimised out' as part of the Optimised Deprival Valuation (ODV) process used to determine allowable revenue.[16]

7.5 Any difference between the estimated cost of the transmission and lines businesses, and associated revenue, will show in the resulting residual margin calculated as part of the analysis.

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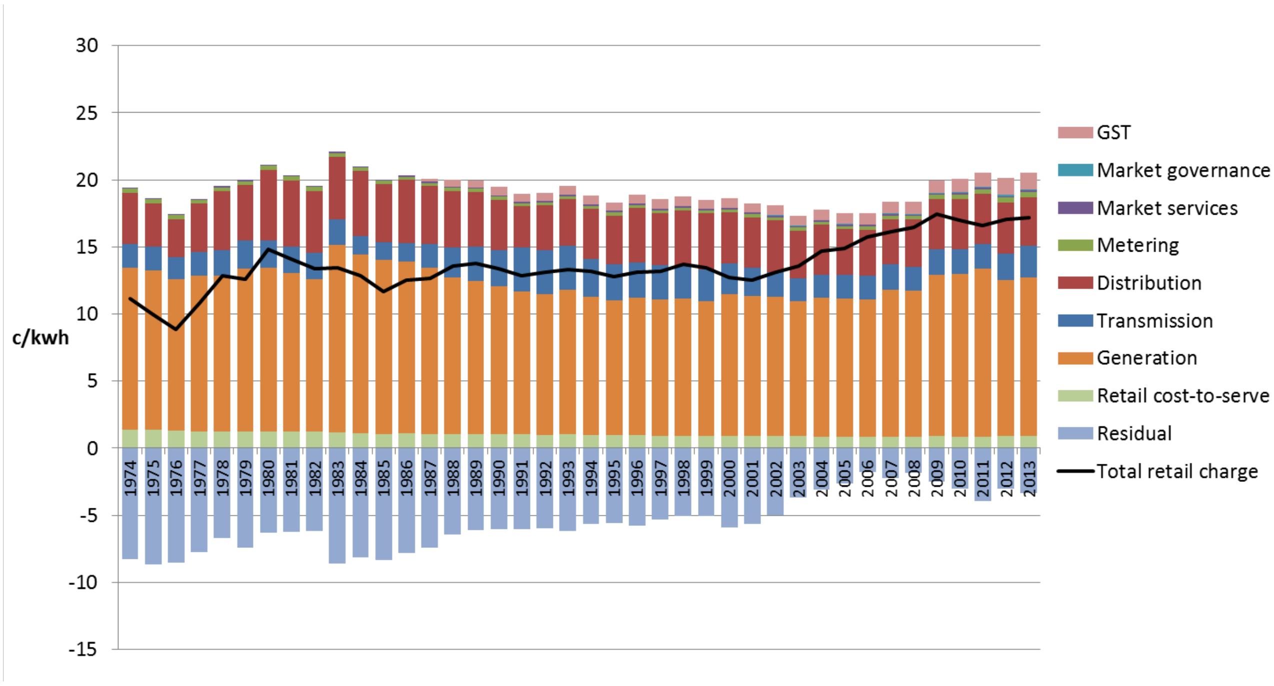
14 Transpower and ECNZ annual reports, Transpower asset valuation reports, lines business disclosure statements, Electricity Commission and Electricity Authority annual reports.

15 Separate lines and energy costs were only available after 1996. The split of lines and energy costs are only estimated prior to that point

16 Scaling was based on the difference between optimised depreciated replacement costs (ODRC), and depreciated replacement costs (DRC) reported for Transpower and the various distribution businesses in their final ODV reports prior to the mid -2000s move to historical-cost based revenue determination. The average difference between ODRC and DRC was 12% for Transpower and 2% for the distribution businesses.

7.6 Using the generating costs estimated using the LRMC approach above, converted to per-unit costs using total actual output, produces the following breakdown of costs across all consumers (values in real 2013 dollars).

Figure 18 Breakdown of costs across all consumers



Source: Electricity Authority Real $2013

7.7 Breakdowns of total revenue and consumption figures published by MBIE are not currently available for periods after the year ended March 2011. The Authority has estimated residential revenue based on changes in quarterly residential price survey data. Revenue from commercial, industrial, and heavy industry consumers has been assumed to be flat since the year-ended March 2011. Changes in consumption volumes since 2011 have been based on data from the reconciliation manager.

7.8 Because the generation cost modelling is at a fairly high level, and there are differences in reporting years for some data, it is difficult to read much into the year-on-year movements. However, it is possible to make a number of general observations.

7.9 It is worth noting that average total charges across all consumers are not much higher now than they were in the early 1980s. If the impact of GST is removed, there has been an increase in real terms of around 8% in total since 1980.

7.10 While the early- to mid-2000s saw retail charges increase relative to generating costs on average across all consumer types, at no time did average total charges exceed estimated costs.

7.11 Average generating costs have gradually reduced since the 1980s, increasing again since the early 2000s, mainly as a result of increasing fuel costs. There have also been recent, lesser, impacts on total consumer retail charges associated with the increase in GST in 2010, and increases in transmission charges.

7.12 The cumulative under-recovery resulting from the negative residual values shown above will have been borne by a mix of taxpayers and company shareholders. The incidence depends mainly on the timing and size of historical asset revaluations and write-offs relating to the corporatisation of NZED assets and, in some cases, the sale of generating businesses and assets to private ownership.

7.13 When ECNZ was established in 1988 there was a substantial asset valuation process prior to the generation assets being transferred to the new company. At that point there was a disconnect between the amount spent on generating assets in the past by NZED, and the forecast value of the assets going forward. In pure book-value terms there was a significant upwards valuation of generation assets when they were transferred to ECNZ. However, it should be recognized that this is in respect to the nominal value of the assets rather than the values expressed in real terms which is how the Authority has approached its modelling.

7.14 As noted above, the Authority tested a number of scenarios in which revaluations were estimated and included in the modelling. The Authority concluded that further work was required before this type of approach could provide a useful comparison of returns pre- and post-corporatisation.

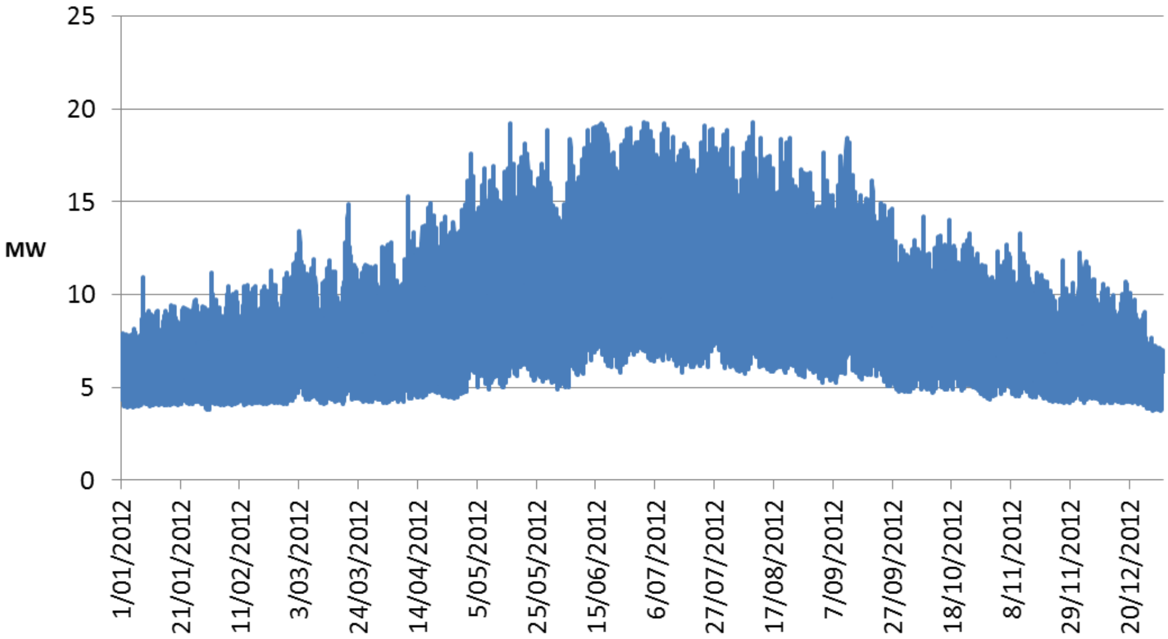
8 Cost of servicing different consumer types

8.1 The generating cost of meeting different types of consumption depends on the profile of the demand it is servicing. Generation suitable for meeting fairly constant levels of consumption over time (baseload generation) is generally cheaper to run than generation that is more suited to ramping up-and-down in order to meet variable demand (peaking generation). As a result residential load, which is generally peakier than other load, is more expensive to serve.

8.2 The following chart shows an example of load at a grid exit point that serves a typical residential area (in this case Pauatahanui near Wellington).[17]

[17] All non-direct-connect GXPs serve a mix of loads. While Pauatahanui serves mainly residential consumers, it also serves a mix of farming and commercial consumers.

Figure 19 Half hourly load profile at Pauatahanui

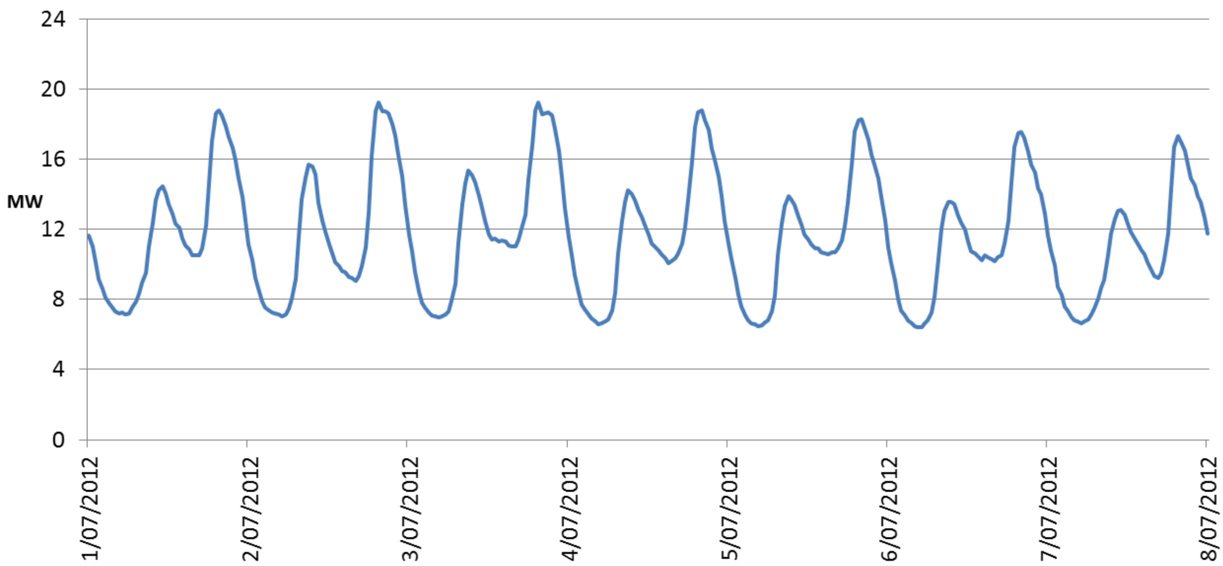


Source: Electricity Authority

8.3 Average consumption over winter is almost twice as high as consumption during the summer months. Focusing on a week's consumption at the beginning of July shows a typical residential winter daily peaking pattern, with a morning peak and a more pronounced evening peak.

Figure 20 Typical residential winter daily load shape

Pauatahanui consumption first week of July 2012

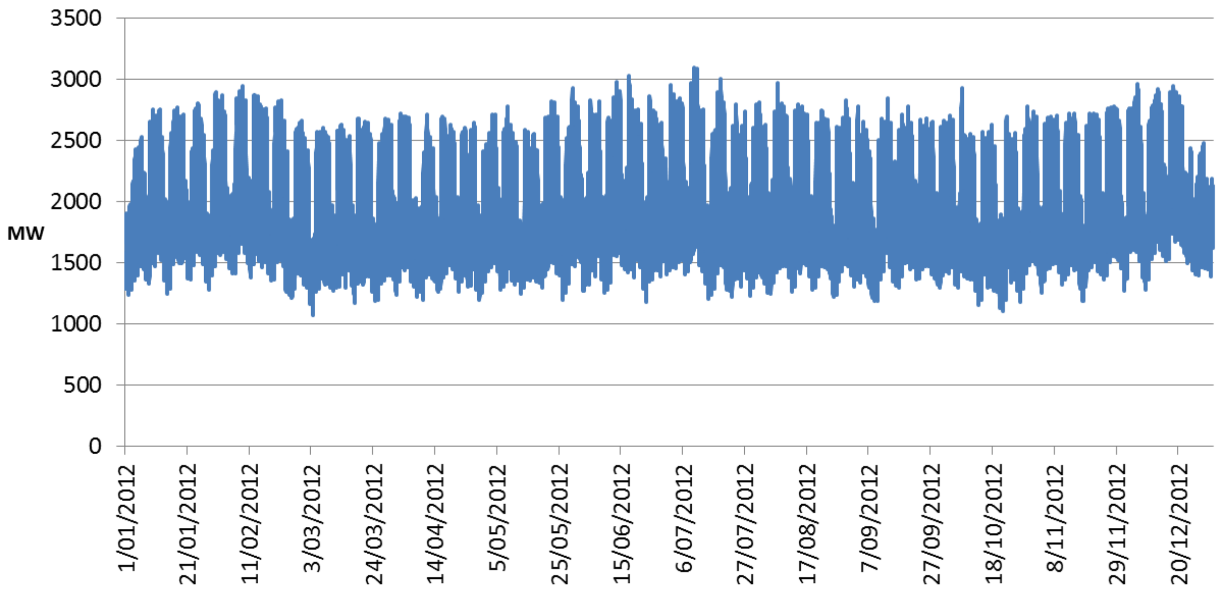


Source: Electricity Authority

8.4 While national commercial and industrial profile information is not readily available, the Authority has estimated a total combined profile for the two sectors by subtracting half-hourly data for the heavy industrial plant directly connected to the transmission grid, and an estimated residential profile based on selected residential grid exit point data.[18]

8.5 The following charts show the resulting load profile for the 2012 year and a snapshot of the load shape for the first week of July.

Figure 21 Half hourly commercial and industrial load profile 2012

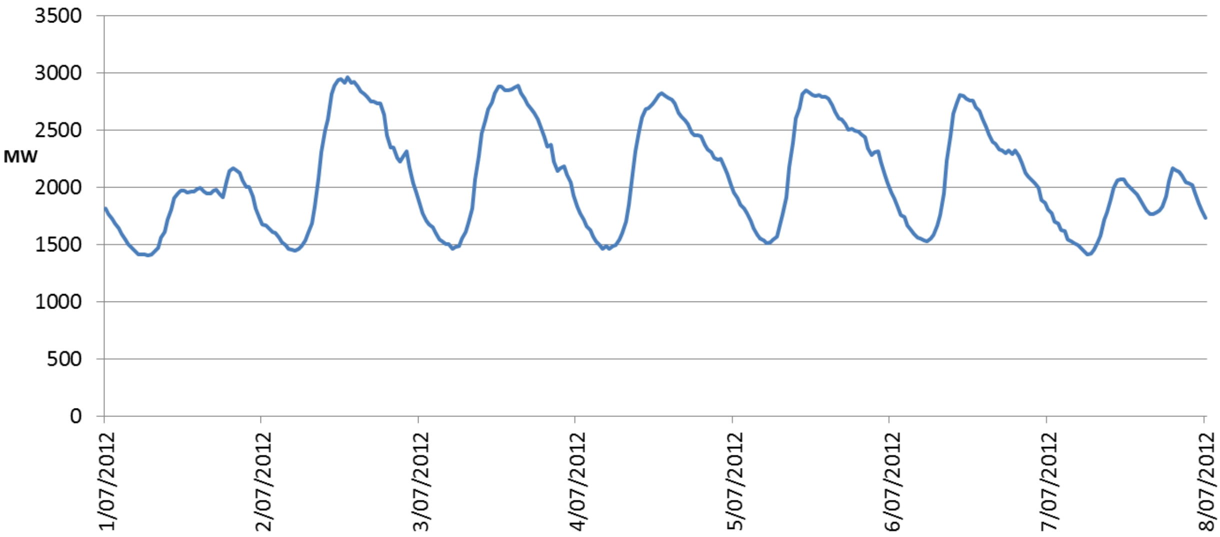


Source: Electricity Authority

[18] Pauatahanui in the North Island and Halfway Bush in the South Island. Reconciliation manager consumption data has been used rather than net metering data to adjust for the impact of generation embedded behind the Halfway Bush grid exit point.

Figure 22 Commercial and industrial daily load shape

First week of July 2012

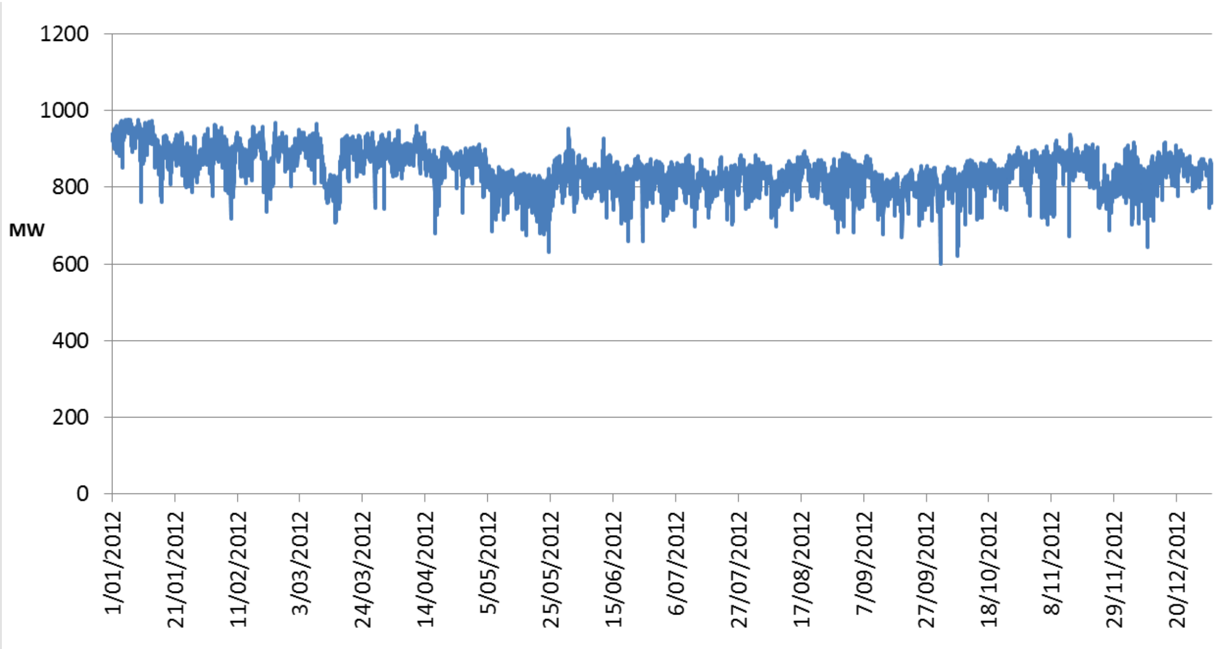


Source: Electricity Authority

8.6 The combined commercial and industrial load is generally flatter across the year relative to the residential load. July 1st and July 7th in the sample above were weekend days, and illustrate the difference in profile between a normal week-day and 'non-working' days.

8.7 The following charts show the load profile for heavy industrial load in 2012.

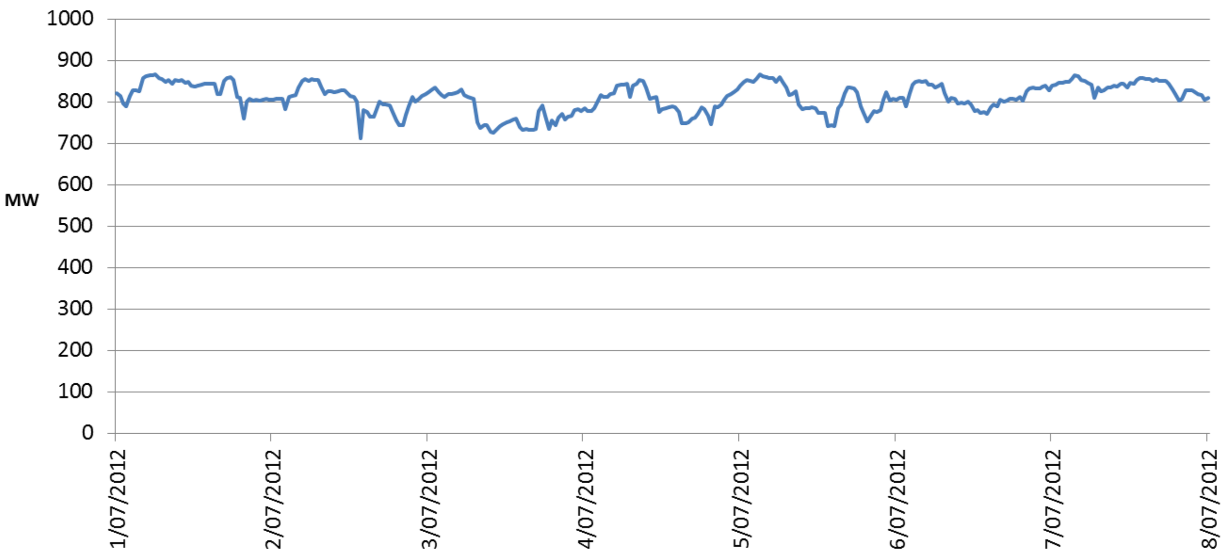
Figure 23 Half hourly heavy industrial load profile 2012



Source: Electricity Authority

Figure 24 Heavy industrial daily load shape

First week of July 2012



Source: Electricity Authority

8.8 The heavy industrial profile is dominated by the load at the Tiwai Point Aluminium Smelter. Demand is very flat, both across the year, and over shorter time periods, as illustrated in the sample week from July above. Heavy industrial load is largely unaffected by weekends and holidays.

9 Demand profile costing methodology

9.1 In order to estimate the cost of generation required to meet different profile types, the Authority has developed an optimisation model that constructs a least cost-generation build needed to serve a specified half-hourly demand profile shape.

9.2 The model has been developed at an island level, with power flows allowed between each island, and includes reserve generation requirements.

9.3 The model simulates half hourly demand from 1990. Year-on-year demand growth is based on historical demand levels, although demand growth in any given year has been forced to be positive to ensure that the model returns LRMC values rather than switching to Short Run Marginal Cost (SRMC) values in those years when there was a drop in demand.

9.4 The starting point for the model's generation portfolio is the generating plant that existed prior to 1990. Because of the significant impact the Clyde dam has on available hydro capacity, the model also assumes that the dam is committed and available from 1993 when it was completed.

9.5 Dry year reserve requirements are not dynamically modelled. Because the base for existing hydro plant does not change over the modelled time frame, hydro firming requirements remain the same over the entire modelled period. Energy capacity at Huntly has been removed in the model and treated as being set aside to make some allowance for dry year reserve.

9.6 The model meets any new demand that cannot be supplied by existing generation from a set of generic plant (i.e. the model is not restricted to the plant that was actually built since 1990). There are no minimum constraints imposed on plant size, so the model 'builds' exactly the amount of generation needed in each year. There are maximum size constraints based on assumed maximum resource availability.

9.7 The modelled generating plant types have the following characteristics.

Table 1 Characteristics of the modelled generating plant types

			Capacity		Capital Expense				SRMC components			
		Reserve	MW	MW	$/KW	years		$/MW/year	$/MWh	$/GJ	kJ/kWh	tCO2/PJ
Generation	Region	Provider	Name Plate	Existing Cap	Capital Cost	Capex Life	Depreciation	Fixed Cost	Var O&M Cost	Fuel Cost	Heat rate	Emission
Coal_NI	NI	0	2450	1000	3,083	30	10.4%	154,750	9.60	4.0	10,500	91,200
Geothermal_NI	NI	0	1500	900	5,106	25	9.7%	95,000	1.50	-	10,000	10,000
CCGT_NI	NI	1	2850	1165	1,883	25	10.8%	158,470	4.25	7.5	7,100	52,800
OCGT_NI	NI	1	1750	1325	1,500	25	10.8%	86,300	6.40	7.5	9,000	52,800
Diesel_NI	NI	0	980	155	1,427	25	10.8%	16,200	10.00	35.0	11,000	73,000
Hydro_NI	NI	1	2000	1870	4,765	40	6.0%	34,450	0.02	-	-	-
Diesel_SI	SI	0	980	20	1,427	25	10.8%	16,200	10.00	35.0	11,000	73,000
Hydro_SI	SI	1	5290	3625	4,765	40	6.0%	34,450	0.02	-	-	-

Source: Electricity Authority

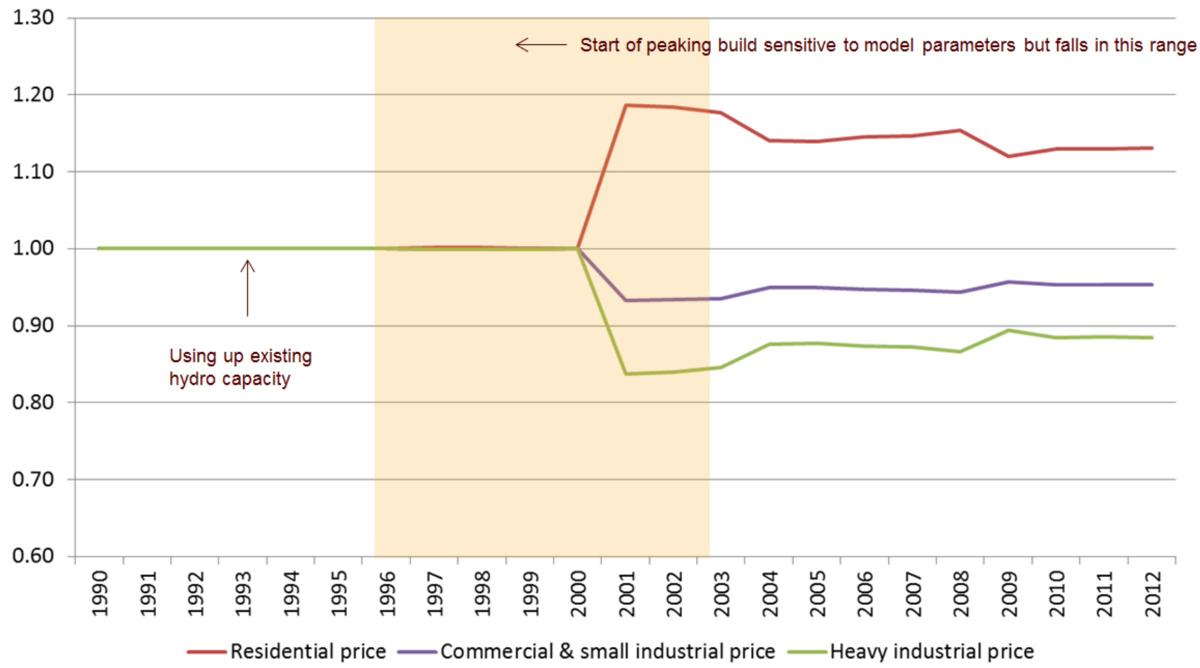
9.8 The model builds sufficient generation to meet total national demand based on the combined consumer demand profiles developed for each consumer type (scaled in each year to match total annual demand). The shadow-prices derived by the model for each of the individual consumer demand profiles represent the LRMC of supplying an additional consumer with a demand profile matching the consumer type in question (i.e. a residential, commercial/industrial or heavy industrial profile). Consumer demand profiles have been based on 2012 metering data.

9.9 A full description of the model is included in Appendix C.

9.10 The additional cost of serving each consumer type, calculated on an annual basis, has been converted to a ratio between the additional cost for each consumer type, and the average total cost in each year across all consumers i.e. the system-wide average.

9.11 The following chart shows the ratios for each consumer type at a national level.

Figure 25 Cost of additional generating capacity for different consumer types relative to the system-wide average



Source: Electricity Authority

9.12 Prior to 2000 there was little or no difference in costs between consumer types because of the excess hydro capacity available to the model i.e. the cost to supply an additional consumer was the same regardless of the shape of their demand profile because existing hydro-generation could meet the extra demand.

9.13 While the modelling assumptions make it appear as though there was no difference in the cost of serving different consumer types prior to 2000, peaking generation existed prior to that point, with some of it in the form of hydro generation. Determining the correct allocation of generating costs to different consumer types prior to the introduction of the electricity market is difficult, as it is unclear whether the excess capacity of some hydro plants was intended to serve peak demand or to address production constraints.

9.14 Prior to the corporatisation of the New Zealand Electricity Department in the 1980's, significant investment was made in hydro generation with relatively little storage. This lack of storage tends to drive investment in plant with a high megawatt capacity to take advantage of periods of high hydro inflows without spilling water. It is therefore debateable whether hydro plant capacity was sized to meet peak demand, or to maximise energy production. Had hydro generation not been built, some other plant would have been needed to meet peak demand.

9.15 In this analysis the Authority has decided to adopt a single cost ratio for the different consumer types, and project that back through the entire modelled period to reflect the higher cost of serving peaky load. If the Authority had only applied the different ratios from 2000 forward, then the historical costs calculated for the different consumer types prior to that date would be different to those presented in this paper.

9.16 The LRMC values produced by the profile model indicate that on average, the cost of supplying additional residential demand was almost 1.15 times the national average cost of supplying additional demand over all consumers. The cost of supplying additional heavy industrial load was about 0.87 times the national average.

10 Profiled generation costs compared to retail charges

10.1 The ratios calculated by the demand profile model have been used to allocate the historical generation costs calculated in Section 6 above to the different consumer types on a year-by-year basis. The Authority has used this approach as it believes that allocating historical generating costs to consumers based on the modelled marginal cost of supply is a better reflection of the cost associated with serving different consumer types than simply using average historical generating costs across all consumers.

10.2 As well as the impact of different load profiles, generating costs associated with supplying loads connected to the local distribution systems are higher than supplying grid-connected loads because of the additional losses over the distribution lines. Average annual distribution losses typically range between 5% and 6% of total load. The Authority has factored up the generating profile ratios for consumers that are not directly grid-connected to reflect the additional cost of losses.

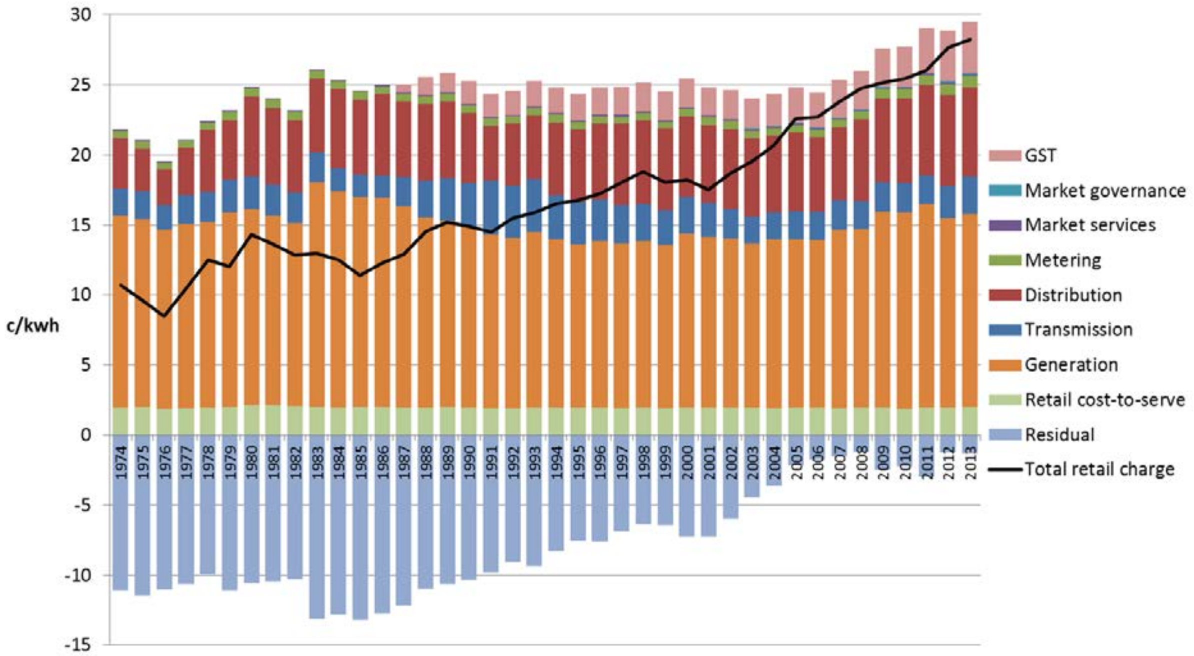
10.3 The combined effect of the profile and losses adjustment is to increase the cost of the generation allocated to residential consumers, and to reduce the cost of generation allocated to commercial, industrial and heavy industrial customers.

10.4 The following charts illustrate the breakdown of costs making up retail charges for each consumer type[19], with generation costs based on the profile modelling.

[19] Total retail charges and individual cost components are based on MBIE consumer group data, and Authority modelled costs.

Figure 26 Residential cost breakdown

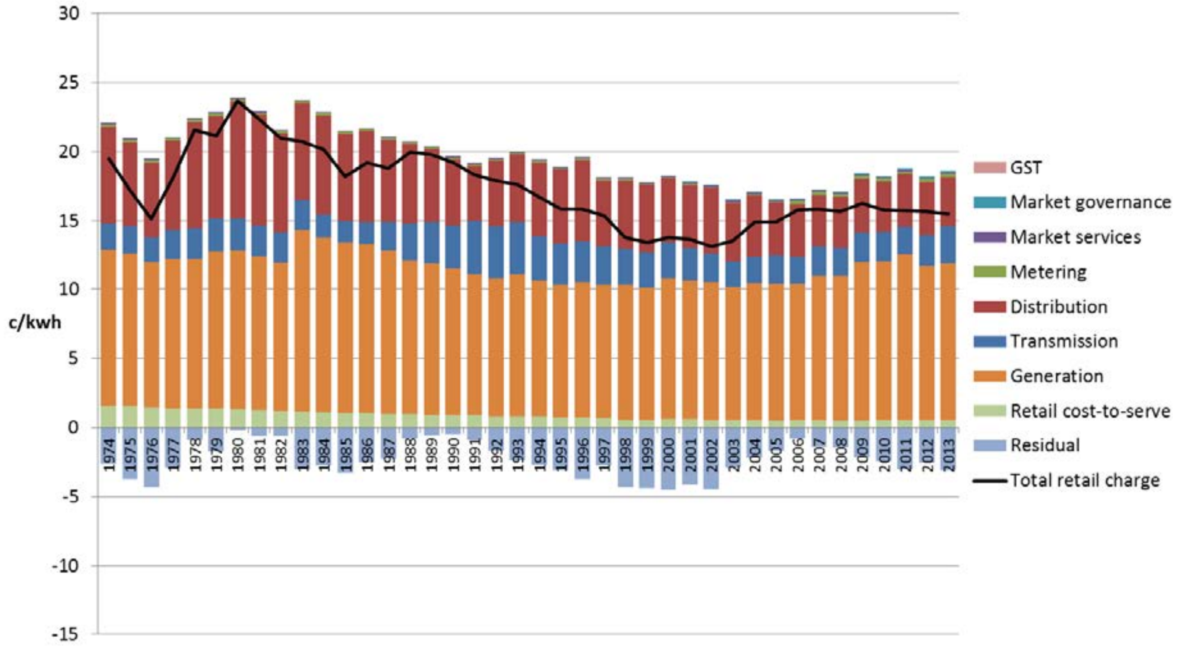
Profiled generation costs



Source: Electricity Authority | Real $2013

Figure 27 Commercial cost breakdown

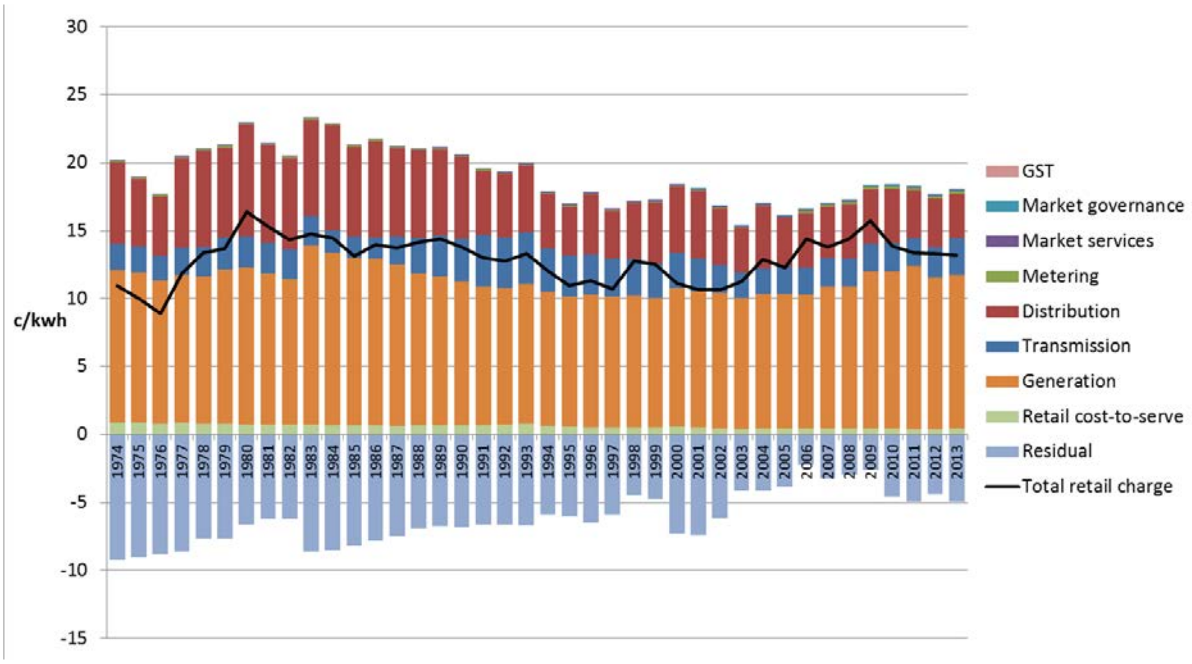
Profiled generation costs



Source: Electricity Authority | Real $2013

Figure 28 Industrial cost breakdown

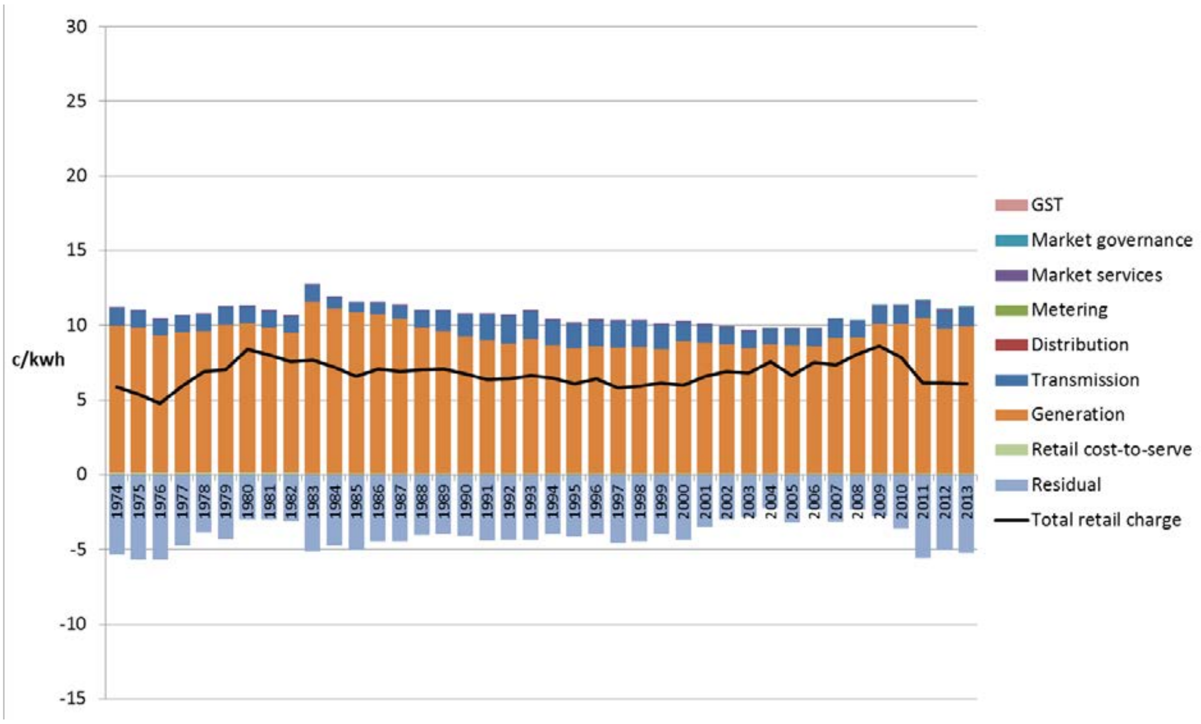
Profiled generation costs



Source: Electricity Authority Real $2013

Figure 29 Heavy industrial cost breakdown

Profiled generation costs



Source: Electricity Authority Real $2013

10.5 The allocation of costs prior to the establishment of the electricity market is fraught with difficulty, as in practice there was no clear linkage between the prices charged to individual consumers and the underlying cost of supplying them with electricity. There is evidence of significant cross-subsidisation between consumer groups in the past. Commercial consumers are the only group that paid close to the modelled average cost of electricity supply between the 1970s and 1990s, while other consumers paid well under the cost of supply. It wasn't until the late-1990s that the margin between actual retail prices and the estimated total cost to supply commercial consumers started to bear some resemblance to the margins faced by other consumer types (shown as the light blue 'Residual' in the charts above).

10.6 More recently, the modelling suggests that residential consumers are currently paying close to the total cost to serve them based on historical cost, while other consumers are paying less than total cost.

10.7 The Authority conjectures that the transition to a competitive electricity market may have forced industry participants to more clearly relate prices charged to consumers to the cost of serving them, as not doing so would allow competitors to 'cherry-pick' consumers that are effectively over-charged.

10.8 The modelling discussed in Section 9 above suggests that at its inception, the market inherited a generation system with excess capacity. For a period it would not have been possible for retailers to differentially charge on the basis of the generating costs associated with serving different consumer profiles. When that excess capacity was used up it became necessary for retailers to differentially charge to avoid competitors undercutting them.

10.9 It should be recognised that there may be some aspects associated with serving different consumer types that have not been captured in the modelling. For example, wholesale market prices are generally more volatile at peak times than during periods with low load, so retailers may be placing a risk margin on residential consumers to reflect this volatility. Some consumer types more actively manage their exposure to movements in wholesale electricity prices than others, through hedging and demand response. This would be expected to influence the residual margins for industrial and heavy industrial consumers in particular, as the costs associated with risk management are incurred directly by the organisations undertaking them rather than by the retailers.

10.10 Since 2005 average residential retail charges have remained close to the total estimated cost of supplying residential consumers based on historical costs. Increases in total residential retail charges over recent years appear to be matched by an equivalent increase in total underlying costs based on Authority modelling.

10.11 Commercial, industrial and heavy industrial consumers all appear to be paying less than the estimated total cost of supply based on historical generating costs, with the margin between charges and costs increasing over the past few years. This is particularly true of the heavy industrial consumers.

10.12 It is useful to compare the above results to the cost of new generating plant. The estimated short-run marginal cost of new gas plant was estimated at $40/MWh as part of the profile costing work above.[20] As the amount paid by heavy industrial consumers is higher than this, the heavy industrial retail prices are still 'efficient' in the sense that they cover the SRMCs of generating, while not over-recovering total costs.

11 Summary and conclusions

11.1 The electricity industry has gone through a number of significant changes since the 1970s. As cost and policies have changed, the amount paid for electricity by different consumer groups has shifted over time.

11.2 Although charges to consumers have increased since the 1970s in nominal terms, in real terms they are not much higher now on average than they were in the early 1980s. This is not true for individual consumer types. Residential consumers have seen significant increases in real terms, while commercial customers have experienced a significant reduction in charges (see Figure 10 on page 6).

11.3 The potential issues associated with the supply and publication of retail data provided to MBIE need to be kept in mind when considering the results over recent years. Based on estimated breakdowns of cost for each consumer group though, there is evidence of significant cross-subsidisation between groups in the past. While commercial consumers appear to have paid close to the total cost of electricity supply between the 1970s and 1990s, other consumer types paid well under the total cost. It wasn't until the late-1990s that the margins between cost and retail charges paid by commercial consumers started to bear some resemblance to those faced by other consumer types.

11.4 When considering relative changes in prices, the cost of supplying different consumer types is important, as the nature of the demand profiles associated with each consumer type impacts on changes in generating costs.

11.5 Average generating costs have gradually reduced since the 1980s, increasing again since the early 2000s, mainly as a result of increasing fuel costs. There have also been recent, lesser, impacts on total consumer retail charges associated with the increase in GST in 2010, and increases in transmission charges.

20 Based on a projected future gas price of $5/GJ for new contracts. The 2012 gas price was $7.15/GJ based on MBIE price data.

11.6 Looking at individual consumer types, it does not appear that recent changes in residential retail charges have increased margins over underlying industry costs associated with that sector. Since 2005 average residential retail charges have remained close to the total estimated cost of supplying residential consumers based on historical costs.

11.7 Commercial, industrial and heavy industrial consumers all appear to be paying less than the estimated total cost of supply based on historical generating costs, with the difference between charges and costs increasing over the past few years.

11.8 Economic theory would suggest that competing profit-maximising companies would price in a way that would result in similar margins within each consumer type. The significant difference in margins produced by this analysis suggests that the modelling does not reflect some key drivers of retail pricing. The margin paid by residential consumers relative to other consumers indicates there may be scope for improvement in the residential retail market. Residential consumers *as a whole* do not appear to be achieving the same reduction in retail margins as other consumer types. However, anecdotal evidence suggests that residential consumers are often receiving significant price reductions when they 'shop around' for lower prices or when retailers approach them to switch to them. The data published by MBIE does not fully capture these discounts.

12 Further proposed work

12.1 It is planned to further refine the analysis work presented in this paper. As noted earlier, changes in plant utilisation over time are not currently modelled as part of the calculation of plant LRMC values. The Authority intends to expand this part of the modelling, and to improve its current estimates of historical fuel costs and other general input data and assumptions.

12.2 The additional LRMC modelling work should also provide a better picture of expected future cashflows in each year, which can then be compared to actual historical asset valuation changes.

12.3 The load profiles used in the modelling of the cost of supplying different consumer types were based on a single year's data. There is evidence that the shape of the load profiles associated with different consumer types has changed over time. The Authority would like to explore these changes in more detail and to integrate them into the modelling if appropriate.

12.4 There are also potentially a number of other aspects associated with serving different consumer types that have not been captured by the modelling to date. For example, it may be valid to incorporate a return into the analysis reflecting the higher price risk associated with serving 'peaky' consumers.

Appendix A List of generating plant capital costs and operating assumptions

NZED Plant

Plant	Build Year	Cost ($m)	Build year CPI (adj)	CPI ratio	$2013 cost	Cap. MW	Annual GWh
Lake Coleridge	1914	0.200	27	37.8	7.6	4.5	25
Lake Coleridge Stage 2	1917	0.100	27	37.8	3.8	1.5	8
Lake Wakatipu control	1920	0.002	27	37.8	0.1	0.1	0.1
Lake Coleridge Stage 3	1923	0.300	25	40.8	12.3	6	30
Mangahao	1924	3.570	26	39.3	140.2	19.2	100
Monowai	1925	0.766	25	40.8	31.3	6	40
Lake Coleridge Stage 4	1926	0.800	26	39.3	31.4	15	40
Tuai	1929	1.409	25	40.8	57.6	32	140
Lake Coleridge Stage 5	1930	0.473	25	40.8	19.3	7.5	30
Arapuni	1932	3.901	22	46.4	181.0	60	300
Arnold	1932	0.354	22	46.4	16.4	3	20
Waitaki	1934	5.532	20	51.0	282.4	75	350
Arapuni Stage 2	1938	1.157	24	42.5	49.2	51	250
Lake Waikaremoana control	1939	0.929	25	40.8	37.9	0.1	0.1
Tuai Stage 2	1939	1.791	25	40.8	73.2	28	80
Lake Taupo control	1941	0.419	27	37.8	15.9	0.1	0.1
Piripaua	1943	2.155	29	35.2	75.9	42	130
Cobb	1944	1.237	29	35.2	43.6	12	60
Highbank	1945	1.281	30	34.0	43.6	25.2	93
Arapuni Stage 3	1946	1.157	30	34.0	39.4	51	250
Karapiro	1948	8.748	33	30.9	270.6	90	525
Kaitawa	1948	3.419	33	30.9	105.8	36	90
Tekapo A	1951	7.365	38	26.9	197.9	25	160
Lake Pukaki control	1951	4.620	38	26.9	124.1	0.1	0.1
Maraetai	1953	19.186	44	23.2	445.2	180	880
Waitaki Stage 2	1954	4.170	46	22.2	92.6	30	150
Whakamaru	1956	24.116	49	20.8	502.4	100	490
Roxburgh	1956	41.374	49	20.8	862.0	160	1350
Cobb Stage 2	1956	8.856	49	20.8	184.5	20	130
Meremere	1958	35.679	51	20.0	714.2	180	950
Wairakei	1958	16.827	51	20.0	336.8	69	450
Atiamuri	1959	19.436	55	18.6	360.8	63	210
Lake Hawea control	1959	4.915	55	18.6	91.2	0.1	0.1
Ohakuri	1961	21.673	56	18.2	395.1	112	400
Waipapa	1961	15.793	56	18.2	287.9	51	240
Atiamuri Stage 2	1962	1.054	58	17.6	18.6	21	70
Roxburgh Stage 2	1962	8.006	58	17.6	140.9	160	300
Aratiatia	1964	16.213	60	17.0	275.9	90	330
Wairakei Stage 2	1964	29.716	60	17.0	505.6	123	850
Benmore	1965	66.656	63	16.2	1080.1	540	2500
Matahina	1967	30.157	67	15.2	459.5	72	290
Marsden A	1967	30.816	67	15.2	469.5	240	400
Meremere Stage 2	1967	3.373	67	15.2	51.4	30	150
Aviemore	1968	37.546	71	14.4	539.8	220	930
Maraetai Stage 2	1971	20.618	86	11.9	244.7	180	1
Lake Manapouri control	1971	11.873	86	11.9	140.9	0.1	1
Lake Te Anau control	1971	9.810	86	11.9	116.4	0.1	1
Manapouri	1971	119.441	86	11.9	1417.8	585	4800
Tongariro control (incl. Tokaanu)	1973	224.110	99	10.3	2311.0	200	660
New Plymouth	1974	136.307	109	9.4	1276.6	600	700
Stratford	1976	30.520	145	7.0	214.9	200	400
Tekapo B	1977	116.186	164	6.2	723.2	160	800
Lake Pukaki control Stage 2	1977	69.368	164	6.2	431.8	0.1	0.1
Lake Coleridge Stage 6	1977	3.512	164	6.2	21.9	0.1	72
Whirinaki 1	1978	28.204	188	5.4	153.2	220	500
Highbank Stage 2	1979	0.834	208	4.9	4.1	0.1	1
Twizel control	1979	7.616	208	4.9	37.4	0.1	0.1
Upper Waitaki control	1979	7.746	208	4.9	38.0	0.1	0.1
Ohau A	1980	152.689	246	4.1	633.6	264	1150
Rangipo	1983	285.394	370	2.8	787.4	120	580
Huntly	1983	722.898	370	2.8	1994.6	1000	5695
Ohau B	1984	145.265	383	2.7	387.2	212	970
Ohau C	1985	98.348	434	2.4	231.3	212	970
Marsden B	1979	115.750	208	4.9	568.1	250	1000
Marsden B Retirement	1979	0.000	208	4.9	0.0	-250	-1000
Otahuhu A	1968	15.695	71	14.4	225.7	180	600
Otahuhu A Stage 2	1978	12.234	188	5.4	66.4	90	300
Otahuhu A Retirement	1987	0.000	552	1.8	0.0	-270	-900

Post Electricity Division (ECNZ or subsequent organisation changes to NZED plant)

Plant	Build Year	Cost ($m)	Build year CPI (adj)	CPI ratio	$2013 cost	Cap. MW	Annual GWh
Arapuni Stage 4	1990	50.000	626	1.6	81.6	31	5
Meremere Retirement	1991	0.000	654	1.6	0.0	-210	-1100
Clyde	1992	1700.000	659	1.5	2634.8	432	2050
Mangahao Stage 2	1994	17.000	674	1.5	25.8	14.2	26
Tongariro control (incl. Tokaanu) Stage 2	1996	25.000	716	1.4	35.6	40	100
Marsden A Retirement	1997	0.000	730	1.4	0.0	-240	-400
Matahina Stage 2	1998	60.000	739	1.4	82.9	0.1	0.1
Lake Coleridge Stage 7	2000	6.000	749	1.4	8.2	4.5	65
Stratford Retirement	2001	0.000	772	1.3	0.0	-200	-400
Whirinaki 1 Retirement	2001	0.000	772	1.3	0.0	-220	-500
Manapouri Stage 2	2002	210.265	792	1.3	271.0	125	1
Mangahao Stage 3	2004	15.000	825	1.2	18.6	4	10
Wairakei Stage 3	2005	70.000	847	1.2	84.4	14	90
Arapuni Stage 5	2007	20.000	898	1.1	22.7	1	0.1
Manapouri Stage 3	2007	90.000	898	1.1	102.3	140	70
Benmore Stage 2	2010	67.000	975	1.0	70.1	0.1	70
New Plymouth Retirement	2011	0.000	1007	1.0	0.0	-600	-700

Non Electricity Division

Plant	Build Year	Cost ($m)	Build year CPI (adj)	CPI ratio	$2013 cost	Cap. MW	Annual GWh
Kawerau - TPP	1966	2.200	64	16.0	35.1	37	271
Lloyd Mandeno	1972	9.000	93	11.0	98.8	15.6	70
Lower Mangapapa	1976	6.804	145	7.0	47.9	6	17
Aniwhenua	1979	27.000	208	4.9	132.5	25	105
Ruahihi	1981	27.000	284	3.6	97.1	20	76
Wheao and Flaxy Scheme	1982	32.000	328	3.1	99.6	24	115
Teviot	1983	14.000	370	2.8	38.6	10.5	55
Paerau	1984	14.000	383	2.7	37.3	10	48
Patea	1984	69.000	383	2.7	183.9	30.7	118
Glenbrook	1987	21.000	552	1.8	38.8	38	190
Ohaaki	1989	300.000	598	1.7	512.0	116	400
Te Awamutu - Anchor Products	1995	40.000	701	1.5	58.2	54	190
Bay Milk Edgecumbe	1996	16.000	716	1.4	22.8	10	54
Hau Nui	1996	10.500	716	1.4	15.0	3.65	10
Kiwi Dairy, Hawera (Whareroa)	1996	70.000	716	1.4	99.7	69.6	180
Southdown	1996	140.000	716	1.4	199.5	125	600
Glenbrook Stage 2	1997	57.000	730	1.4	79.7	74	360
Poihipi Rd	1997	78.000	730	1.4	109.1	55	350
Rotokawa	1997	50.000	730	1.4	69.9	29	240
Kapuni	1998	25.000	739	1.4	34.6	25	130
Kinleith	1998	50.000	739	1.4	69.1	28	250
Ngawha	1998	40.000	739	1.4	55.3	10	80
TCC - Taranaki Combined Cycle	1998	400.000	739	1.4	552.8	385	2200
Opuha	1999	30.500	738	1.4	42.2	7.5	21
Tararua	1999	50.000	738	1.4	69.2	31.7	128
Te Rapa	1999	34.000	738	1.4	47.0	44	200
Mokai	2000	225.000	749	1.4	306.5	55	440
Otahuhu B	2000	456.000	749	1.4	621.2	380	2240
Rotokawa Stage 2	2003	20.000	812	1.3	25.2	6	50
Hau Nui Stage 2	2004	13.000	825	1.2	16.1	4.8	13
Huntly P40	2004	50.000	825	1.2	61.9	48	335
Tararua Stage 2	2004	55.000	825	1.2	68.1	36.3	147
Te Apiti	2004	190.000	825	1.2	235.1	90.75	258
Whirinaki 2	2004	150.000	825	1.2	185.6	155	9
Mokai Stage 2	2005	60.000	847	1.2	72.3	40	325
Otahuhu B Stage 2	2005	30.000	847	1.2	36.2	24	140
Pan Pac	2005	11.000	847	1.2	13.3	12.8	48
Te Awamutu - Anchor Products Retirement	2007	0.000	898	1.1	0.0	-54	-190
Southdown Stage 2	2007	54.000	898	1.1	61.4	45	250
Mokai Stage 3	2007	15.000	898	1.1	17.1	17	140
Huntly e3P	2007	506.000	898	1.1	575.4	400	2410
Tararua Stage 3	2007	180.000	898	1.1	204.7	93	375
White Hill	2007	100.000	898	1.1	113.7	58	200
Ngawha Stage 2	2008	77.000	928	1.1	84.7	15	120
Kawerau Geothermal	2008	300.000	928	1.1	330.0	100	800
West Wind	2009	430.000	956	1.1	459.4	143	550
Nga Awa Purua	2010	430.000	975	1.0	450.2	140	1100
Te Huka	2010	100.000	975	1.0	104.7	23	190
Mahinerangi	2011	75.000	1007	1.0	76.0	36	112

Non Electricity Division (continued)

Plant	Build Year	Cost ($m)	Build year CPI (adj)	CPI ratio	$2013 cost	Cap. MW	Annual GWh
Marsden Diesel	2011	10.800	1007	1.0	10.9	9	0.1
Mount Stuart	2011	17.000	1007	1.0	17.2	7.65	25.6
Stratford Peaker	2011	250.000	1007	1.0	253.3	200	350
Te Rere Hau	2011	80.000	1007	1.0	81.1	48.5	160
Te Uku	2011	200.000	1007	1.0	202.7	64.4	225
Kawerau - TOPP 1	2012	42.000	1012	1.0	42.4	25	210
Ngatamariki	2013	466.000	1021	1.0	466.0	82	670
McKee	2013	100.000	1021	1.0	100.0	102	300
Waipori	1907	0.070	27	37.8	2.6	2	5
Waipori Stage 2	1913	0.140	27	37.8	5.3	4	10
Waipori Stage 1 & 2 retirement	1922	0.000	26	39.3	0.0	-6	-15
Waipori Stage 3	1922	0.720	26	39.3	28.3	21.8	50
Waipori Stage 4	1929	0.130	25	40.8	5.3	4	10
Waipori Stage 5	1946	0.110	30	34.0	3.7	3	7.5
Waipori Stage 6	1955	0.820	48	21.3	17.4	13.6	31
Waipori Stage 7	1968	1.600	71	14.4	23.0	18	45
Waipori Stage 8	1976	6.560	145	7.0	46.2	36	90
Waipori Stage 3 retirement	1980	0.000	246	4.1	0.0	-21.8	-50
Waipori Stage 4 retirement	1983	0.000	370	2.8	0.0	-7	-17.5
Waipori Stage 9	1983	4.650	370	2.8	12.8	10	23

Appendix B NZIER WACC recommendation

26 November 2013

Brian Kirtlan
Principal Advisor
Electricity Authority

Sent by email to brian.kirtlan@ea.govt.nz

Dear Brian

WACC parameters for 'Retail price analysis'

You asked me to provide you with advice on an appropriate value or values for a pre-tax real Weighted Average Cost of Capital (WACC) for modelling returns on generator-retailers assets from 1974 through to 2012.

I recommend the use of a single (pre-tax real) WACC value of 10.1%. In the table below is a selection of alternative measures of the same rate should these be needed.

The value of 10.1% is slightly higher than a WACC which might be applied today – my estimate is 9.3% - because it is a value constructed to be applicable over a decadal time frame.

Parameter	Value
Single value for 1974 - 2012	
Real Pre-tax WACC	10.1%
Nominal Vanilla WACC	13.2%
Nominal Post-tax WACC	12.1%
Nominal Pre-tax WACC	17.3%
Real Vanilla WACC	6.3%
Real Post-tax WACC	5.2%

Below I discuss some of the reasons why a single WACC value is appropriate – albeit not 'perfect'. I then outline the method and formulae and assumptions used to populate the WACC estimates.

Effect of reforms on WACC – a single value is, on balance, best

You have expressed a preference for limiting the number of parameters that need to be modelled in order to keep your analysis tractable. I see no strong reason, on balance, to adopt multiple WACC rates. A single number is reasonable under the circumstances.

In principle, multiple WACC rates might be used to take account of changes in the nature of government involvement in management of and investment in generation assets, for example. Multiple rates might also be used to take account of time varying debt premia, changes to asset betas, time varying market risk premia, or the implications of falling debt values for sustainable leverage ratios. This sort of extremely detailed evaluation of asset specific WACCs over time would be interesting but resource intensive. Absent the time and resource to conduct detailed analysis, it makes sense to keep things simple.

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Risk premia and government vs private debt

One area where the single WACC rate might seem counter-intuitive is that a constant WACC value of 10.1% implies a premium over the risk free debt rate regardless of whether generator-retailers have direct access to crown debt finance or not.

It is possible that Crown entities would have had or could have access to debt at preferential rates, at least implicitly. Thus a case can be made for reduced debt premia and lower WACC rates prior to reform and privatisation of select electricity generation assets.

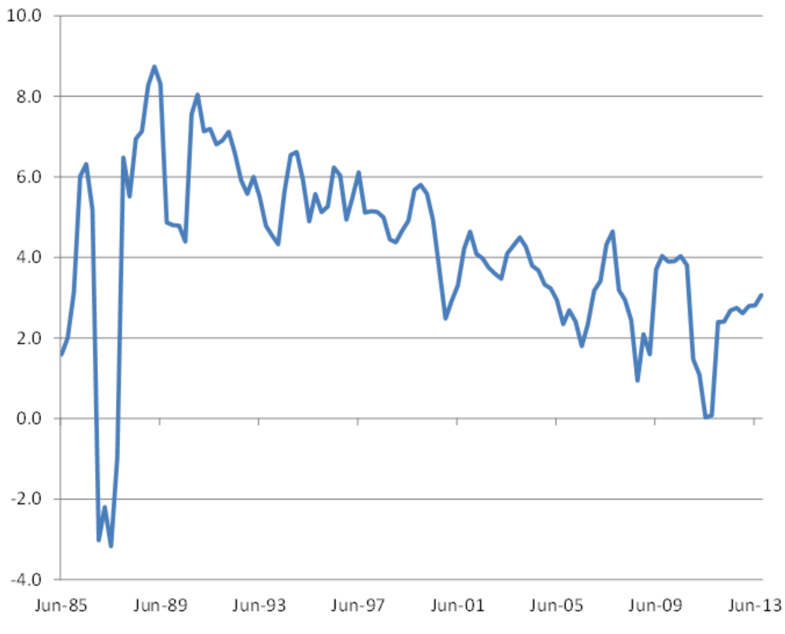
It is, however, difficult to determine the reduction in debt premia that Crown investments would receive in practice. It is not necessarily the case that large scale capital investment would be subject to the same required rates of return on debt as Government bonds in general.

Furthermore, the rate at which government borrows is not independent of decisions to invest. When investment is large enough (such as large infrastructure investment programmes) and part of an overall government spending programme it can contribute to a lift in government bond rates, especially nominal rates if Crown spending drives inflation as it did in the 1970s and 1980s.

In any case, Crown borrowing should be applied so as to produce a return commensurate with the opportunity of cost of the debt raised. Investment should thus be subject to a test of whether or not it can match the average rate of return achieved on similar classes of investment, irrespective of the cost of debt. This is the general approach of the Treasury and one which is consistent with value for money.

Finally, it is worth noting that the declining cost of debt over time means that dividing debt costs up into pre-reform rates and post-reform rates would mean higher pre-reform WACC and lower post reform WACC.

Figure 1 Real government bond rates trending down over time



Source: NZIER, RBNZ

Method and formulae

We have built up our estimate of WACC using the same approach as the Commerce Commission for estimating the cost of capital of regulated entities. [1] This has the benefit of being simple and relatively widely understood:

$$WACC = r_d L + r_e(1 - L)$$

where:

- r_d is cost of debt capital, which equals $r_f + p$, where r_f is the 'risk free rate' and p is the debt premium
- L is $D/(D + E)$, D is debt, and E is equity
- r_e is cost of equity capital.

The cost of equity capital r_e (using a "simplified version of the Brennan-Lally model") is[2]:

- $r_e = r_f(1 - t) + \left(r_m - r_f(1 - t)\right)\beta_e$

where:

- t is the relevant tax rate
- r_m is the expected return on the market portfolio (an unobservable portfolio comprising all available assets in the market)
- β_e is the equity beta (the linear relationship between the expected return on an asset and the systematic risk associated with holding that asset)
- $r_m - r_f(1 - t)$ is the 'tax adjusted market risk premium', or the $TAMRP$.

Pre-tax WACC has been calculated as:

$$r_d L + r_e \frac{(1+L)}{(1-t)}.$$

[1] New Zealand Commerce Commission (2009) *Revised Draft Guidelines, The Commerce Commission's Approach to Estimating the Cost of Capital*, page 16, and equation 9(b) on page 49.

[2] NZCC (2009) page 22

Assumptions

Parameters	Ranges
Risk free rate (r_f)	10.7% (4.2% real) Monthly average of 10-year government bonds since 1985.[3]
Debt premium (p)	2.7% Based on the average mark-up over the risk free rate (40%) observed in published equity analyst (MacQuarie and FirstNZ capital) valuations for generator retailers in the past 6 years.[4] This compares to Commerce Commission estimates for Transpower (July 2013) and EDBs (April 2013) of 1.85% and 2.05% respectively for information disclosure.
Leverage (L)	25%. Based on average of leverage assumptions used in published equity analyst (MacQuarie and FirstNZ capital) valuations for generator retailers in the past 6 years. By comparison, Meridian Energy is currently 19%.[5] Contact Energy currently 28%.[6]
Tax rate (t)	30% The average of crown tax receipts to GDP since 1974.[7]
Tax-adjusted Market risk premium $(TAMRP)$	7.0% Value referenced in Commerce Commission EDB & Transpower Input methodology. Compares to 7.1% average of assumptions used in published equity analyst (MacQuarie and FirstNZ capital) valuations for generator retailers in the past 6 years.
Inflation	6.5% average since 1974 (source: RBNZ)
Equity beta (β_e)	0.73 Based on average of estimates used in published equity analyst (MacQuarie and FirstNZ capital) valuations for generator retailers in the past 6 years. Most recent published estimates were 0.69 for MRP and 0.78 for Meridian Energy estimated by First NZ Capital.[8]

John Stephenson
Principal Economist, NZIER

3 RBNZ. Consistent data not available pre-1985.

4 Main source is equity valuation reports for SOE generator-retailers available at http://www.comu.govt.nz/publications/information-releases/valuation-reports/.

5 *http://media.nzherald.co.nz/webcontent/document/pdf/201340/FirstNZMeridian.pdf.*

6 *http://investing.money.msn.com/investments/stock-price/?symbol=DE:BZB.*

7 Fiscal time series available at http://www.treasury.govt.nz/government/data. Data is an approximation given changes in accounting standards and movement from cash basis to accrual.

8 *http://media.nzherald.co.nz/webcontent/document/pdf/201340/FirstNZMeridian.pdf*

Appendix C Profile model formulation

Profile Demand Constraint

- For each demand profile in each region, the period demand is a ratio of yearly average demand of that demand profile

$$DEMANDPROFILE_{t,r,lp} \times {}^{1}\!/_{LoadFactor_{t,r,lp}} = AvgDemand_{r,lp}$$

t period/time series in a year [1 .. 17568]
r regions. Ex: NI & SI
lp load profile. Ex:Commercial, Industrial and Residential

Regional Demand Constraint

- For each region, the period total demand is the sum of period demand of all demand profiles

$$DEMAND_{t,r} = \sum_{lp} DEMANDPROFILE_{t,r,lp}$$

t period/time series in a year [1 .. 17568]
r regions. Ex: NI & SI
lp load profile. Ex:Commercial, Industrial and Residential

Max Built Generation Capacity

- For each region r and each generation technology g, the total generation capacity is less than the nameplate capacity (see generation technology data table)

$$ADDEDCAPACITY_g + ExistCapacity_g \le NamePlate_g + OVERBUILT_g$$

g group of generation technology. Ex: Geothermal_NI, Hydro_NI, CCGT_NI, Hydro_SI etc…

Max Period Generation Output

- For each generation technology g, periodic generation output is limited by capacity-factor-adjusted installed capacity

$$GENERATION_{t,g} - OVERGENERATION_{t,g} \le OperatingCapFactor_{t,g} \times \left[ADDEDCAPACITY_g + ExistCapacity_g\right]$$

t period/time series in a year [1 .. 17568]
g group of generation technology. Ex: Geothermal_NI, Hydro_NI, CCGT_NI, Hydro_SI etc…

Note: Operating capacity factor varies by technology, time of the year.

Min Period Generation Output

- For each generation technology g, periodic generation output is limited by capacity-factor-adjusted installed capacity

$$GENERATION_{t,g} - UNDERGENERATION_{t,g} \le MustRunFactor_{t,g} \times \left[ADDEDCAPACITY_g + ExistCapacity_g\right]$$

t period/time series in a year [1 .. 17568]
g group of generation technology. Ex: Geothermal_NI,Hydro_NI,CCGT_NI, Hydro_SI etc…

Monthly Expected Generation

- For each generation technology g (geothermal and hydro), monthly generation output is limited by the expected monthly capacity factor estimated using historical data.

$$-MONTHLYGENVIO_{m,g} + \sum_{t \in m} GENERATION_{t,g} \leq \sum_{t \in m} \left[ExpectMonthOutputRatio_{m,g} \times \left(ADDEDCAPACITY_g + ExistCapacity_g\right)\right]$$

t	period/time series in a year	[1 .. 17568]
m	month in a year	[1 .. 12]
g	group of generation technology. Ex: Geothermal_NI, Hydro_NI and Hydro_SI.	

Energy Balance Constraint

- For each region r and each period t, total generation output plus imported energy minus exported energy is equal to region's demand.

$$\sum_{g\ in\ r} GENERATION_{t,g} + \sum_{\substack{tx1 \\ to\ region\ r}} 0.9 \times POWERFLOW_{t,tx1} - \sum_{\substack{tx2 \\ from\ region\ r}} POWERFLOW_{t,tx2} + DEFICITGEN_{t,r} = DEMAND_{t,r} + SURPLUSGEN_{t,r}$$

t	period/time series in a year	[1 .. 17568]
tx	transmission link	[N2S, S2N]
g	group of generation technology.	

Note: 10% loss is applied for power flow on transmission link

Power Flow Constraint

- Power flow on a transmission link is limited by its capacity.

$$POWERFLOW_{t,tx} \leq TxCapacity_{tx} + TXOVERFLOW_{t,tx}$$

t	period/time series in a year	[1 .. 17568]
tx	transmission link	[N2S, S2N]

Region Reserve Constraint

- For each region r and each period t, total generation output plus imported energy minus exported energy is equal to region's demand.

$$\sum_{fk\ in\ r} \begin{bmatrix} \left(ADDEDCAPACITY_{fk} + ExistCapacity_{fk}\right) \times OperatingCapFactor_{fk} \\ -GENERATIONg_{t,fk} \end{bmatrix} + DEFICITRES_{t,r} \geq Demand_{t,r} \times ReserveRatio$$

t	period/time series in a year	[1 .. 17568]
r	regions. Ex: NI & SI	
fk	group of generation technologies which can provide reserve service → fk $\in$g.	

Objective Function – Minimise Cost

$$COST = \sum_g \left(AnnualCapitalCharge_g \times ADDEDCAPACITY_g\right) + \sum_g \left(FixedCost_g \times ADDEDCAPACITY_g\right) + \sum_{t,g} \left(Srmc_g \times GENERATION_{t,g}\right) \times 0.5(hrs) \sum_v (Penalty_v \times VIOLATION_v)$$

v collection of violation types. non-zero $VIOLATION_v$ indicates infeasible solution.

Marginal cost to supply a demand profile

$$DemandProfileMarginalCost_{lp} = \frac{1}{\sum_t 1} \times \sum_t MCtr1_{t,lp}$$

t	period/time series in a year	[1 .. 17568]
$MCtr1_{t,r,lf}$	Marginal cost of constraint 1	\$/MWhalfhr

SETS

t	time series in a year	[1 .. 17568]
m	trading month	[1 .. 12]
r	regions	[NI, SI]
tx	transmission link	[N2S, S2N]
lp	load profile – load type	
g	group of generation	
fk	group of generation can provide ancillary service – fk∈g	

Parameters

$AnnualCapCharge_{g}$	Annualised capital charge of generation group g	\$/MW
$FixedCost_{g}$	Annual fixed cost of technology generation group g	\$/MW
$Srmc_{g}$	Short-run marginal cost of generation group g	\$/MWh
$AvgDemand_{r,lp}$	Yearly average demand of load profile lp in region r	MW
$ExistCapacity_{g}$	Existing generation capacity of generation group g	MW
$NamePlate_{g}$	Max total built capacity of generation group g	MW
$TxCapacity_{tx}$	Capacity of transmission link tx	MW
$LoadFactor_{t,r,lp}$	Period load distribution factor of load profile lp in region r	
$OperatingCapFactor_{t,g}$	This factor is used to calculate the operating capacity of generation group g in period t	
$MustRunFactor_{t,g}$	This factor is used to calculate the minimum generation output of generation group g in period t	
$ExpectMonthOutputRatio_{m,g}$	This ratio is used to calculate the max (expected) total volume of generation output of generation group g in month m (hydro, geo)	

Positive variables

$DEMANDPROFILE_{t,r,lp}$	Demand of load profile lp in region r during period t	MW
$DEMAND_{t,r}$	Total demand of region r during period t	MW
$ADDEDCAPACITY_{g}$	Total added capacity of generation group g	MW
$GENERATION_{t,g}$	Output of generation group g during period t	MW
$POWERFLOW_{t,tx}$	Power flows on transmission link tx during period t	MW
$OVERBUILT_{g}$	Capacity constraint violation	MW
$DEFICITGEN_{t,r}$	Deficit generation in region r during time period t	MW
$SURPLUSGEN_{t,r}$	Surplus generation in region r during time period t	MW
$DEFICITRES_{t,r}$	Deficit of reserve to meet reserve requirement	MW
$OVERGENERATION_{t,g}$	Upper bound violation of generation output	MW
$UNDERGENERATION_{t,g}$	Lower bound violation of generation output	MW
$MONTHLYGENVIO_{m,g}$	Violation of expected monthly generation	MW
$TXOVERFLOW_{t,tx}$	Amount of overflow on transmission link	MW

Glossary of abbreviations and terms

Authority	Electricity Authority
Contact	Contact Energy Limited
CPI	Consumer Price Index
ECNZ	Electricity Corporation of New Zealand Limited
EECA	Energy Efficiency and Conservation Authority
Genesis	Genesis Energy Limited.
LRMC	Long run marginal cost
MBIE	Ministry of Business, Innovation and Employment
Meridian	Meridian Energy Limited
MW	Megawatt
MWh	Megawatt hour
NZED	New Zealand Electricity Department
NZIER	New Zealand Institute of Economic Research
SRMC	Short run marginal cost
WACC	Weighted average cost of capital