Report on the history of the Bulk Supply Tariff and Transmission Pricing in New Zealand

Prepared for:
Trustpower Limited

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Preface

Strata Energy Consulting Limited specialises in providing services relating to the energy industry and energy utilisation. The Company was established in 2003. Strata Energy Consulting provides advice to clients through its own resources and through a network of associate organisations. Strata Energy Consulting has completed work on a wide range of topics for clients in the energy sector in both New Zealand and overseas.

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Executive Summary

History of charges for energy and transmission

The history of electricity supply in New Zealand stretches back to the 1880s but the major developments involving the State date from 1914 in the South Island, with the commissioning of Coleridge, and from 1919 in the North Island, with the purchase of the Horahora power station from the Waihi Gold Mining Company. Mangahao was the first power station constructed by the State in the North Island and it was commissioned in 1924.

While the initial supplies to end use consumers came from local generation, bulk supply from the state to local authorities became the norm in the 1930s. The prices paid by supply authorities were based solely on winter peak demand[1]. The urban authorities that had their own generation were therefore able to manage their costs, unlike the rural power boards without generation which were also unable to spread the demand costs over the consumption of a large number of consumers.

Charges based solely on the basis of peak demand continued through the introduction of the Bulk Supply Tariff (BST) in 1954. During the 1960s bulk supply charges continued to be based only on demand, but the unit was changed from a kVA rate to a kW rate. Prices were relatively stable in nominal terms.

From 1 April 1967, the structure of the BST was amended to introduce an energy component, and this two-part structure remained relatively stable until April 1984 when a more cost-reflective seasonal structure was introduced. The volatility of the prices over the period was significant, with a price freeze between 1970 and 1976 followed by significant increases in 1977, 1978 and 1980.

From 1 April 1984 to 31 March 1989 the structure of the BST was amended to introduce seasonal and time of day rates and a differential between the North Island and the South Island rates.

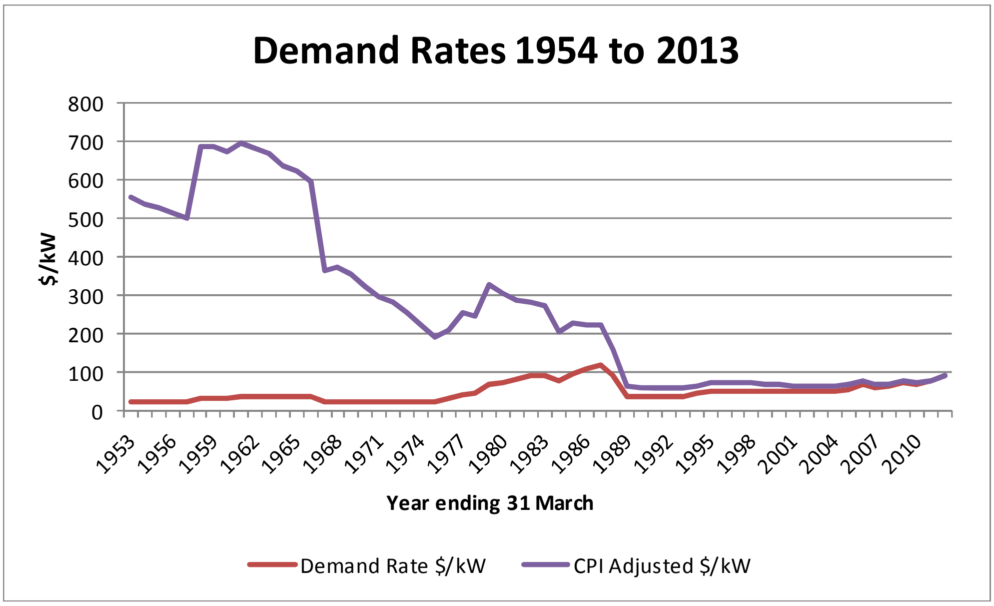
Over the period from 1988 to 1991 there was a gradual unbundling of the BST into a series of pricing options for customers. Explicit charges for transmission were introduced when Transpower was separated from the Electricity Corporation of New Zealand (ECNZ). ECNZ initially set charges for energy but these were later set by the wholesale electricity market, after its introduction in 1996.

From 1995, Transpower continued developing its transmission pricing methodology (TPM) by designing a pricing structure for transmission based on Connection, Capacity and Network charges, until its final evolution in 2008 into the current TPM.

Despite the changes to ownership structures and the evolution of the power system, throughout this entire period from the 1930s there has always been a charge on grid connected electricity consumers based explicitly on peak demand. At times the charge has been lower than current rates (in real terms), but at times it has been significantly higher; however, the pricing signal itself has endured.

The demand rates over the period since the introduction of the BST are summarised in the figure below in both nominal terms and as adjusted to 2013 money by the CPI.

[1] Reilly, Helen: *Connecting the Country: New Zealand's National Grid 1886-2007,* Steele Roberts, Wellington 2008, p.90.



Investment driven by pricing signals

Load Management

The nature of the tariffs applicable over the period 1954 to 1988 led primarily to supply authorities being incentivised to reduce their electricity costs by controlling the kW demand they imposed on the power system. The use of ripple control for rationing water heating was an obvious tool for reducing demand charges while maintaining supply for other purposes.

The separation of line and energy functions on Power Companies in 1999 saw, in many networks, the separation of the responsibilities for ripple control transmission plant and receivers, with Distributors generally being the owners of the transmission plant and retailers either owning or leasing receivers.

There has been, and there continues to be, substantial investment in load management equipment related to avoidance of peak load charges. That investment has deferred the generation plant and network infrastructure that would have been required to meet an estimated additional 880MW of load.

Distributed Generation

The EA's working paper on ACOT provides a comprehensive review of the development of distributed generation and contains statistics relating to the numbers and types of embedded generating stations. Not all of these installations received payments for avoided cost of transmission charges. Some are owned by distributors, some are probably not being used to reduce peak demand charges and others are relatively small and would not qualify. The total installed capacity of a subset of the embedded generation that the EA considered significant is in the region of 850MW.

The paper also provides information on the installed capacity for which payments were made over the period 2008 to 2011. It estimates that approximately $50 million will be paid to 766 MW of qualifying generation during 2013/14.

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Introduction

1. The Electricity Authority (EA) published a working paper "Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation" dated 19 November 2013 and asked for submissions by 31 January 2014.

2. Trustpower has asked Strata Energy Consulting (Strata) to provide a report setting out:

   (a) A brief history of pricing to grid connected customers; and

   (b) The responses of grid connected customers to the pricing signals.

Purpose

3. The purpose of this report is to:

   (a) provide an historical perspective on the pricing signals seen by grid-connected customers over the period 1954 to 1988, and from 1988 to 2013[2];

   (b) identify any policy drivers that contributed to decisions about the form of the Transmission Pricing Methodology;

   (c) illustrate how demand charges have been used as investment signals by grid connected customers; and

   (d) show how grid connected customers have responded to these investment signals by investing in:

      (i) ripple control; and

      (ii) distributed generation.

Background

4. The history of electricity supply in New Zealand stretches back to the1880s but the major developments involving the State date from 1914 in the South Island with the commissioning of Coleridge and from 1919, in the North Island with the purchase of the Horahora power station from the Waihi Gold Mining Company. Mangahao was the first power station constructed by the State in the North Island and it was commissioned in 1924.

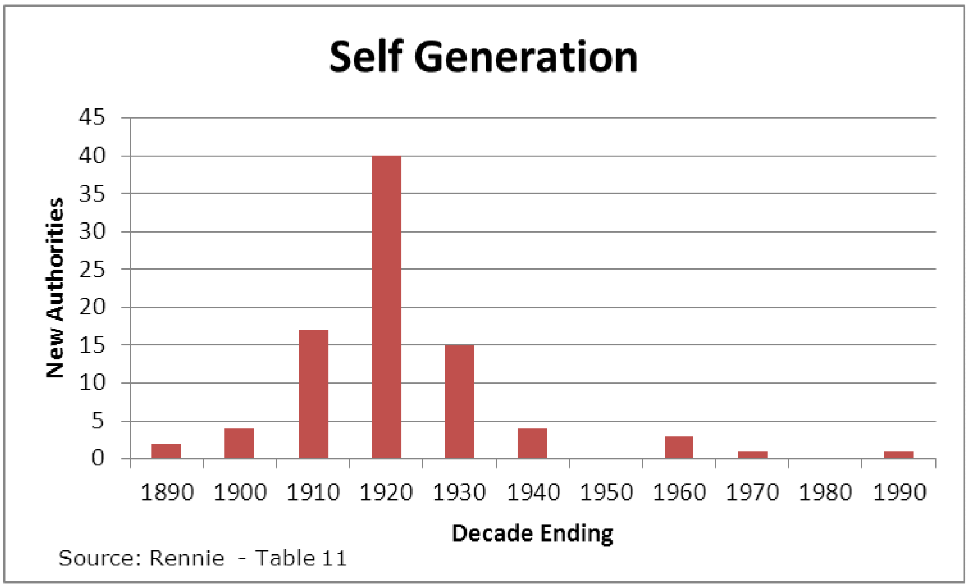
5. Before the State started to take over supply of generation and transmission in 1914 with the commissioning of Lake Coleridge Power station, local authorities and industrial plants provided their own electricity supply. Between 1888, when the first public supply at Reefton was installed, and 1914, 35 local supply authorities had

[2] A uniform Bulk Supply Tariff (BST) was introduced between the State Hydro Electricity Department (SHED) and Electricity Supply Authorities in 1954. The BST was unbundled by the Electricity Corporation in 1988.

installed generating plants or taken supply from a local industry like a dairy factory or meat works.[3]

6. Figure 1 shows the growth in local authorities which established their own generation from 1888, (Reefton B) to 1988 (Stewart Island). These exclude new authorities established with bulk supply from the State and established authorities that subsequently added self-generation.

Figure 1: New Authorities with Self-Generation 1898 to 1998



7. The major stimulants to the growth of the number of local supply authorities were the 1918 Electric Power Boards Act which empowered the establishment of supply authorities beyond municipal boundaries, and the Municipal Corporations Act of 1920 which enabled municipalities to build generating stations and supply within and outside their municipal boundaries.[4] By the 1930s most of the supply authorities were connected to SHED and problems with the pricing methodology were beginning to become apparent.

8. The prices paid by supply authorities were based on winter peak demand[5]. The urban authorities that had their own generation were able to manage their costs, unlike the rural power boards without generation which were also unable to spread the demand costs over the consumption of a large number of consumers.

9. In 1935 a special committee comprising representatives of the Public Works Department and the supply authorities investigated bulk supply charges. While their investigation did not lead to a reduction in the charges, they did recommend that charges should be fixed on a sliding scale in order to encourage the supply authorities

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[3] Rennie, Neil: *Power to the People: 100 Years of Public Electricity Supply in New Zealand,* Electricity Supply Association of New Zealand, Wellington 1989. Table 11

[4] *Ibid., p.93.*

[5] Reilly, Helen: *Connecting the Country: New Zealand's National Grid 1886-2007,* Steele Roberts, Wellington 2008, p.90..

to make full use of the power[6]. This resulted in in lower costs per kWh with increasing usage.

10. The rates per kVA seem to have been fixed at the 1932 levels for demand up to 15,000 kVA until 1948/49 with the only changes being the level at which the marginal rate applied.

11. The original blocks were[7]:

(a)	First 200kVA	$5 per quarter
(b)	Next 4,800 kVA	$4 per quarter
(c)	Next 15,000 kVA	$3.50 per quarter
(d)	Over 20,000 kVA	$2.625 per quarter

12. By 1948/49 the structure and rates had become:

(a)	First 200kVA	$5 per quarter
(b)	Next 4,800 kVA	$4 per quarter
(c)	Next 15,000 kVA	$3.50 per quarter
(d)	Next 45,000 kVA	$3 per quarter
(e)	Over 70,000 kVA	$3.25 per quarter

13. These rates applied through to 1953.

14. Effectively, smaller supply authorities with demands below 15,000 kVA saw no increases in their rates through to 1953. Given the very high growth in demand in the post war period, despite the continuation of war-time rationing, they would have seen substantial reductions in their cost per kWh.

15. Larger authorities would have seen incentives to improve costs per kWh. They would also have been advantaged by increasing demand growth, as well as having the ability to manage demand with generation, in some cases.

Development of the Bulk Supply Tariff

Introduction of Uniform BST

16. The 1950s saw the New Zealand economy (and birth rate) booming and a huge effort being made to increase the national infrastructure, particularly the electricity supply.

17. By 1953 there was some easing in electricity rationing and SHED held discussions with the electricity supply authorities (ESAs) over the bulk supply charges. The Minister (Stan Goosman) announced that his Department was working on a uniform Bulk

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[6] *Ibid. p.93.*

[7] *A History of Wholesale Electricity Pricing" From April 1987 to September 1996,* Internal Electricity Corporation of New Zealand (ECNZ) Report, April 1997. This report contains an appendix which summarises the Bulk Supply Tariffs from 1914 through to 1988. The appendix has been reproduced as Appendix 1 of this report.

Supply Tariff (agreement) and that there would be an increase in in the bulk supply charges[8]. The revised structure for 1953/54 was:

(a) First 200 kW[9] $6 per quarter

(b) Next 19,800 kW $5.75 per quarter

(c) Next 30,000 kW $5.25 per quarter

(d) Over 50,000 kW $5.45 per quarter

18. In 1954 the uniform Bulk Supply Agreements were issued and these had provisions for annual adjustments. This tariff, which would be valid until 1958, was designed to provide electricity to the ESAs at cost. There is no record of any adjustments being made in the interim.

19. The Electricity Amendment Act 1957 enabled the SHED to price electricity to produce a 25% margin on operating costs (excluding loan repayments), and to enable any surplus to be applied firstly to reduction of capital liability, and secondly to credit the Reserve Fund. The arrangement was to be effective from 1 April 1958. However, capital contributions were deferred until 1961. See Appendix 1.

20. The year 1958 was significant in that due to the arrival of thermal generation (Meremere Power Station), SHED changed its name to the New Zealand Electricity Department (NZED) and rationing ceased in the North Island.[10] Also in 1958, a single demand rate of $8.50[11] per kW per quarter was introduced. If the reduction was passed to domestic consumers, the charge was further reduced by 50c. In October 1961 the tariff was amended to $8.50 per kW per quarter and this rate appears to have been in effect until 1966. See Appendix 1.

21. Table 1 shows the published demand rates over the period 1954 to 1967. It is not clear whether the increase to enable 25% capital contribution was actually applied in 1958 as there were deferrals of the contribution until 1961. See Appendix 1

[8]*Appendices to the Journals of the House of Representatives (AJHR.)*

[9] The switch from kVA to kW for charging removed the financial incentive to maintain a high power factor.

[10] *AJHR* 1959

[11] The currency was in £ s d at the time but all rates have been converted to $ and c

Table 1: Demand Rates 1954 to 1967

Year Ending 31 March	Demand Rate $/kW
1954	21.8
1955	21.8
1956	21.8
1957	21.8
1958	21.8
1959	32
1960	32
1961	32
1962	34
1963	34
1964	34
1965	34
1966	34
1967	34

Introduction of energy component to the BST

22. In 1966 it was agreed between the NZED and the ESAs that the level of the contribution to capital would vary between 25% and 50%. The higher level of contribution was approved by Cabinet to apply from 1 October 1967 through to 31 March 1972. See Appendix 1 for more details.

23. In addition to the change in the capital contribution allocation, changes in the BST structure from 1967 to 1972 were agreed; the BST from 1 April 1967 would be based on an annual maximum demand $/kW rate and a c/kWh rate for energy consumption[12].

24. As a result of the structural changes and the imposition of a higher capital contribution, the 1967 charges were based on an initial BST applicable from 1 April 1967, and a subsequent BST applicable from 1 October 1967. The relevant rates were:

    (a) From 1 April 1967 – to 30 September 1967:

        (i) $19.80 per kW per annum

        (ii) 0.225 c/kWh

    (b) From 1 October 1967 to 31 March 1972 (extended by Government intervention to 1976)

        (i) $23.50 per kW per annum

        (ii) 0.27 c/kWh

[12] AJHR 1966 and Reilly p.165.

25. During the period 1967 to 1976 the country experienced a number of electricity shortages and massive increases in the price of imported energy. Despite the detrimental effect on the financial position of the NZED, the Government maintained the price freeze and relied on restrictions on electricity usage and appeals for conservation to manage the fuel costs (mainly oil) to the NZED.

26. By 1976 the Minister of Electricity (ESF Holland) reported that the NZED, now called New Zealand Electricity, was operating at a deficit, as a result of the price freeze. Because electricity had been priced at an unrealistically low figure, there would be a 60% increase in the BST from 1 April 1976.[13] The rates from 1 April 1976 would be:

(a) $29.21 per kW per annum

(b) 0.61 c/kWh

27. From 1977 to 1983 the structure of the BST remained unchanged, and annual increases were applied (as shown below) together with the average cost per kWh that a bulk supply customer with a load factor of 50% would have paid:

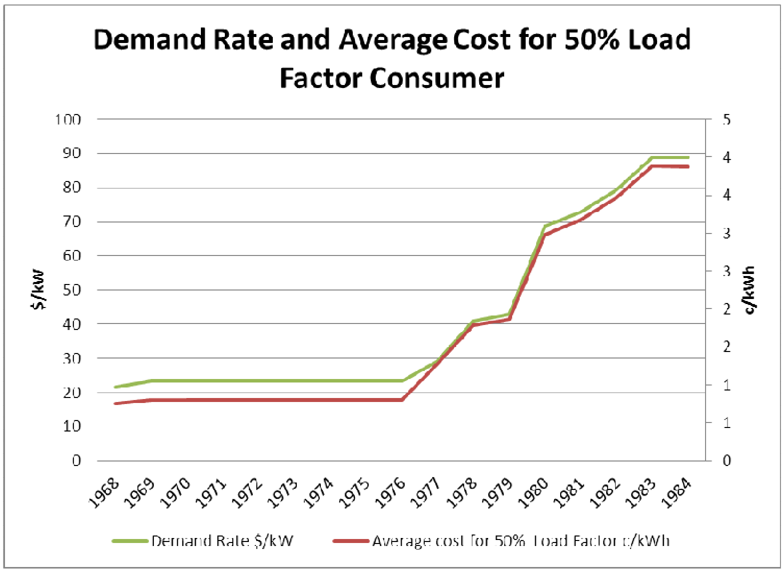
Table 2: BST from 1968 to 1984

Year ending 31 March	Demand Rate $/kW	Energy rate c/kWh	Average cost for 50% Load Factor c/kWh	Annual Increase
1968	21.65	0.27	0.76	
1969	23.5	0.27	0.81	6%
1970	23.5	0.27	0.81	0%
1971	23.5	0.27	0.81	0%
1972	23.5	0.27	0.81	0%
1973	23.5	0.27	0.81	0%
1974	23.5	0.27	0.81	0%
1975	23.5	0.27	0.81	0%
1976	23.5	0.27	0.80	0%
1977	29.21	0.61	1.28	59%
1978	40.89	0.85	1.78	40%
1979	42.93	0.89	1.87	5%
1980	68.69	1.42	2.98	60%
1981	72.81	1.51	3.17	6%
1982	79.36	1.65	3.46	9%
1983	88.88	1.85	3.88	12%
1984	88.88	1.85	3.87	0%

28. The trend in these costs is shown in Figure 2 below in the money of the day

[13] AJHR and Reilly p.167

Figure 2: Demand Rates and Average Costs for 50% Load Factor Consumer



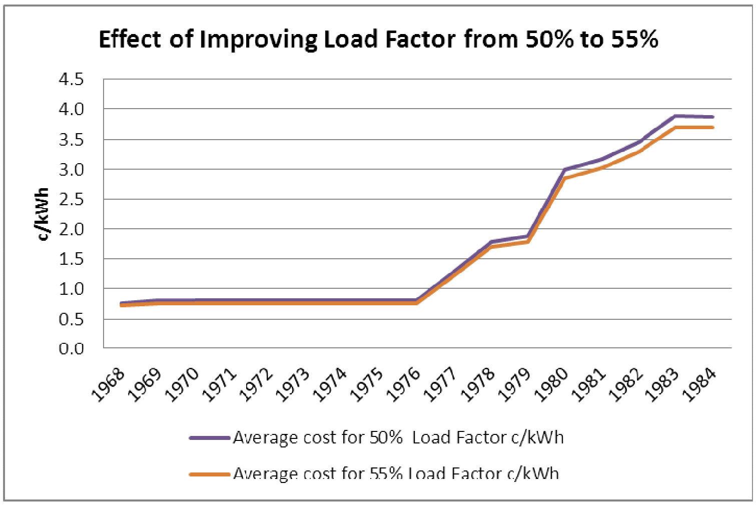
29. The rapid increase in demand charges for a bulk supply consumer provided an incentive to improve the load factor, ie the ratio of the average demand over the year to the maximum demand in the year.

30. Table 3 and Figure 3 show the impact of improving the load factor from 50% to 55%. This could be achieved by using distributed generation to reduce the peak demand, or by shifting load from peak to off-peak periods using load control.

Table 3: Effect of improving load factor from 50% to 55%

Year ending 31 March	Average cost for 50% Load Factor c/kWh	Average cost for 55% Load Factor c/kWh	Saving
1968	0.76	0.72	5.87%
1969	0.81	0.76	6.05%
1970	0.81	0.76	6.05%
1971	0.81	0.76	6.05%
1972	0.81	0.76	6.13%
1973	0.81	0.76	6.05%
1974	0.81	0.76	6.05%
1975	0.81	0.76	6.05%
1976	0.80	0.76	5.96%
1977	1.28	1.22	4.75%
1978	1.78	1.70	4.76%
1979	1.87	1.78	4.76%
1980	2.98	2.84	4.76%
1981	3.17	3.02	4.76%
1982	3.46	3.30	4.76%
1983	3.88	3.69	4.76%
1984	3.87	3.69	4.75%

Figure 3: Effect of improving load factor from 50% to 55%



31. The incentive provided by load factor improvement provided an incentive for investment in load control for grid connected consumers.

Introduction of Seasonal and Time of Use Rates

32. From 1 April 1984 the BST structure was radically altered to provide more pricing signals to grid-connected consumers. These signals highlighted the seasonal and diurnal cost variations seen by the Electricity Division and consumers were encouraged to control demand over the winter period and shift energy usage from day to night.

33. In addition, a 10% differential between North Island and South Island rates was formalised in the tariff structure. This was increased to 22% from 1 April 1986. The differential was eventually turned into an annual subsidy for South Island consumers but later abandoned.

34. Table 4 shows the structure and rates that applied from 1 April 1984 to 31 March 1988. Additional details are available in Appendix 1.

Table 4: Seasonal and Time of Use Rates 1984 to 1989

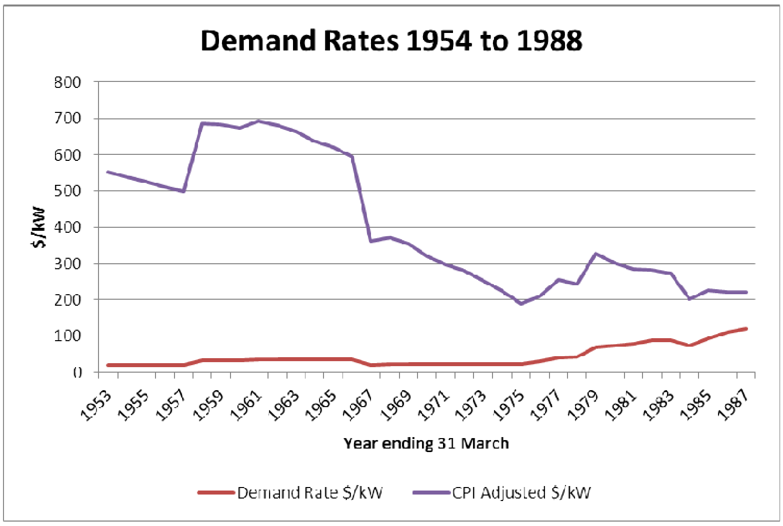
Year ending 31 March	Structure	North Island	South Island
1985	Winter zone demand $/kW	57.88	54.6
	Anytime demand $/kW	16.78.	15.83
	Day rate energy c/kWh	2.443	2.305
	Night rate energy c/kWh	1.955	1.844
1986	Winter zone demand $/kW	73.16	66.5
	Anytime demand $/kW	21.21	19.28
	Day rate energy c/kWh	3.088	2.807
	Night rate energy c/kWh	2.471	2.246
1987	Winter zone demand $/kW	84.5	69.16
	Anytime demand $/kW	24.5	20.05
	Day rate energy c/kWh	3.567	2.919
	Night rate energy c/kWh	2.854	2.336
1988	Winter zone demand $/kW	92.1	75.38
	Anytime demand $/kW	26.7	21.85
	Day rate energy c/kWh	3.888	3.182
	Night rate energy c/kWh	3.111	2.546

35. The BST was extended to 30 April 1988. The new Electricity Corporation replaced it with "Delivered Energy Contracts" which eventually devolved into separate energy and transmission contracts.

36. Figure 4 shows the evolution of demand rates in the BST from 1954 to 1989 (North Island for period 1984 to 1989) in money of the day and as adjusted to 2013 values using CPI[14].

[14] CPI Reference SE9A - New Zealand Statistics

Figure 4: Demand Rates 1954 to 1988



37. The irregular shape of the CPI Adjusted curve can be attributed to changes in the structure of the tariff and the interference of government in the pricing of electricity:

(a) From 1 April 1958 the Government allowed SHED to increase prices to enable contributions towards capital liability reduction;

(b) In 1967, the tariff was restructured to enable a 50% contribution to capital and an energy rate was introduced; and

(c) Prices were held constant during the high inflation period between 1968 and 1976, resulting in very high increases in 1977 and again in 1979.

Evolution of Transmission Pricing post BST

38. The following section outlines the evolution of the New Zealand transmission pricing methodologies over the period 1988 to 2013, and discusses the high level rationale for the development and changes in transmission pricing methodologies over that period.

39. The section identifies the following phases[15]:

Phase 1: 1988 to1996 – during which the BST was unbundled into its energy and transmission components, Transpower was separated from the Electricity Corporation of New Zealand (ECNZ)[16] and Transpower developed its own pricing;

Phase 2: 1996 to 1998 – when the transmission pricing methodology (TPM) of the time was evolved to meet the needs of the newly developed wholesale electricity market, and a number of innovations were introduced to address customer concerns about the TPM;

[15] This section draws on *Report on Transmission Pricing Methodologies 1988 to 2008"* prepared by Strata Energy Consulting Ltd, for the Electricity Commission, June 2009. The full report is available on the EA website at

http://www.ea.govt.nz/search/?q=Report+on+Transmission+Pricing+Methodologies+1988.

[16] Separation occurred in 1994 when Transpower became a State Owned Enterprise.

Phase 3: 1999 to 2008 – during which the current structure of the TPM was developed; and

Phase 4: 2008 to present – during which the TPM was regulated and subsequently amended to introduce regional price signalling.

Phase 1: 1988 to 1996 – Unbundling of BST and TPM development

40. Transmission pricing, as distinct from the pricing of delivered energy to customers connected to the national grid (the grid), was initiated in 1988 when ECNZ established Transpower as a separate, wholly owned subsidiary[17]. After consulting with customers, ECNZ and Transpower developed a detailed pricing structure intended to provide open and equal access to the transmission system for all comers.

41. The initial TPM was developed from the BST. Over the period from 1988 to 1991 there was a gradual unbundling of the BST into a series of pricing options for customers. The first real separation of the energy and transmission services provided by ECNZ was part of the so-called Nominated Quantity Option, which was offered to transmission customers in 1989. The main elements of the pricing structure were:

(a) Connection charges; and

(b) Demand charges;

(i) Network Capacity charge;

(ii) Transmission Service charge; and

(iii) System Support charge.

42. The pricing year was also changed to apply from 1 October to 30 September in 1989, 1990, and 1991. The pricing year was April to March in 1992 and 1993.

43. Table 5 shows Demand rates for the period 1989 to 1994 [18]:

Table 5: Demand Rates 1989 to 1994 (North Island)

Charges	Year Ending 30 Sept 1990	Year Ending 30 Sept 1991	Year Ending 30 Sept 1992	Year Ending 31 March 1993	Year Ending 31 March 1994
Supply Charge Rate $/kW	19.8				
Demand Charge Rate $/kW	66				
System Support Rate $/kW		4	4	4	4
Constraint Charge Rate $/kW		32.4	33.6	33.6	33.6
Total $/kW	85.8	36.4	37.6	37.6	37.6

44. As part of the separation of the contracts and the subsequent separation of Transpower from ECNZ, a transitional revenue neutral pricing arrangement was

[17] Then called Trans Power. This report will use Transpower.

[18] *A History of Wholesale Electricity Pricing" From April 1987 to September 1996.* Internal Electricity Corporation of New Zealand (ECNZ) Report dated April 1997.

introduced to ensure that customers were not subjected to high price increases as a result of the separation.

45. From 1995, Transpower continued developing the TPM and designed a pricing structure based on Connection, Capacity and Network charges.

Phase 2: 1996 to 1999 – Transition to, and impact of, the NZEM

46. In December 1995, Transpower notified its customers of a change to the pricing applicable from 1 April 1996 to: [19]

   (a) introduce optimised replacement cost (ORC) for the purpose of calculating Network and Connection charges. The allocation of network asset usage would continue to be based on network load flow analysis;

   (b) treat HVAC and HVDC assets separately because the economic life for the HVDC assets was considered to be significantly shorter than that of the HVAC assets;

   (c) average the routine maintenance expenditures that accrue to individual network and connection assets;

   (d) split the old Capacity Charge into a new Capacity Charge (50%) and a Demand Charge (50%);

   (e) introduce two Demand Charge options:

      (i) a contracted Demand Entitlement (DE), nominated by customer, with an Excess Demand Charge (EDC) for excess demand on winter weekdays; and

      (ii) a DE (based on the previous year's winter peak demand) with an Incremental Reset when, and if, the DE during winter was exceeded and led to a new DE which would be maintained until exceeded (default option for customers without transmission contracts).

47. In July 1996, further changes were made when Transpower notified its customers of the pricing methodology that would apply from 1 October 1996. This notification was updated in October 1996[20].

48. The reasons for the changes related to "a determination to change what was largely an asset cost-based pricing regime to one that over time would become more service focused and more responsive to individual customer requirements"[21].

49. The changes were:

   (a) replacing Capacity and Demand charges with an Access charge;

   (b) replacing Network charges with Transport charges;

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[19] *Transmission Charges: Application of the Price Methodology for the 1996/97 Contract Year*, Transpower New Zealand Ltd, Nov 1995.

[20] *Pricing for Transmission Services*: 2nd Ed Transpower, October 1996.

[21] *Pricing for Transmission Services: Introduction to the pricing methodology to be applied from 1 October 1996, Transpower* New Zealand Ltd, Oct 1996.

(c) recovering, via Connection charges, the cost of assets required to connect a specific user to the grid. This extended the boundary of existing generator connections to include a greater share of user-specific connection assets (so called "deep connection");

(d) recovering, via Transport charges, future avoidable costs from all grid users. This was to ensure that the marginal price signal faced by grid users was the incremental cost of connection to the grid;

(e) recovering, via Access and Transport charges, unavoidable (sunk) costs from offtake customers only. This was to ensure that fixed transmission costs could not be avoided and that the signals for new investment were not distorted;

(f) transferring the Network charge cap to the Transport charge at any offtake connection point so that it did not exceed the average Transport charge for all such connection charges by more than 50%;

(g) recovering the full cost of the HVDC link from South Island generators and paying the HVDC losses and constraints rentals to South Island generators;

(h) continuing the use of caps on price increases, but based on the rate ($/kW) not the dollar amount;

(i) extending the nominated Demand Entitlement and Demand Charge offer to completely replace the 10 year rolling average-based Capacity Charge and allowing for downward adjustments on the Incremental Reset;

(j) introducing Price Blocks for Access and Transport Charges to provide forward nomination of maximum demand for up to five years. Payment for demand was through the Access and Transport rates multiplied by the Nominated Demand for each Price Block. There were three options for Excess Demand Charges which were subject to adjustments, depending on the option chosen (300:1, 200:1 or 100:1). The higher the expected frequency of excursions above the threshold, the higher the adjusted base rates but the lower the Excess Demand Charge

50. The indicative rates that would apply were:

From 1 Oct 1996 to 31 March 1997	**Base Rate Adjustment Factor**	**Transport plus Access Rate**	**Excess Demand Rate**
Incremental Reset Option		$50.00/kW (Base Rate Example)	
Excess Demand Charge Options			
100:1 Option	4.7%	$52.35/kW	$0.52/kW
200:1 Option	6.0%	$53.00/kW	$0.27/kW
300:1 Option	7.0%	$53.50/kW	$0.11/kW

51. In April 1998, Transpower announced more changes to the methodology[22]:

    (a) the 300:1 Excess Demand Option was no longer available;

    (b) a 50:1 Excess Demand Option was introduced; and

    (c) price blocks were limited to one year.

52. The Base Rate as shown in the example remained at $50/kW. This is assumed to be a representative rate as individual consumers would have received rates based on the option chosen.

Phase 3: 1999 to 2008 – Steady state

53. In April 1999, Transpower announced an enhancement to the transmission pricing methodology applicable from 1 April 1999.[23]

54. This introduced a relatively stable structure for 9 years, albeit with disagreements about the allocation processes.

55. The key differences from the previous methodology are summarised below:

    (a) The introduction of three charges:

        (i) Connection charges for all generators and offtake customers for assigned connection assets created a new definition for connection asset, which removed the previous distinction between "deep connection" assets for generators and "shallow connection" assets for offtake;

        (ii) Interconnection charges for offtake customers only allocated by peak demand ($/kW) removed the Transport charge which allocated 50% of the AC grid assets using a load flow model and the Access charge which recovered the residual revenue requirement. The interconnection charge recovered the residual revenue not recovered from other charges;

        (iii) HVDC charges for South Island generators only, allocated by peak injection MW;

    (b) A proportion of overhead costs was allocated to generators through Connection and HVDC charges. Previously, overhead costs were recovered through Access charges; and

    (c) Demand allocation was based on an incremental reset up, or down, to the average of p highest peaks in the last 12 months (p=12 for that and subsequent years, until the TPM applicable from 1 April 2008 took effect). This replaced the complicated Excess Demand options and the incremental reset based on a single peak.

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[22] *Pricing of Transmission Services: Pricing Methodology from 1 April 1998*, 3rd Ed, Transpower New Zealand Ltd, April 1998

[23] *Pricing of Transmission Services: Pricing Methodology from 1 April 1999*, 4th Ed, Transpower New Zealand Ltd, April 1999.

56. This methodology remained in place until a new TPM was approved by the Minister of Energy in 2007 in accordance with the provisions of part F of the Electricity Governance Rules (EGRs).

57. Transpower's revenue requirement from year to year has been subject to an Economic Value Adjustment (EVA) from 1998/99. The EVA adjusts the revenue requirement for economic gains or losses arising from ODV valuation effects, and incremental costs and revenues arising from non-transmission activities (shareholder account) and other non-shareholder related gains or losses (customer account).

58. The main issues that were addressed with the new structure were:

(a) the difference in the basis for assessing connection assets for generation and offtake, which was addressed by a new connection asset definition;

(b) the complexity and variability of the recovery of the costs of interconnection assets allocated by load flow modelling, which was removed by the introduction of an interconnection charge determined by a $/kW rate measured by an annual capacity requirement;

(c) the severity of the incremental reset of chargeable demand, which was reduced by introducing an average of the 12 highest peaks in the last 12 months; and

(d) the inequitable allocation of overheads, previously recovered from offtake, was shared between offtake and generation customers so as to spread these more equitably.

59. This new structure had the benefit of being simpler in its application and the demand related charges were:

Table 6: Rates for interconnection charges 2000 to 2007

Year Ending 31 March	Demand Rate $/kW
2000	50
2001	49
2002	48.36
2003	50.18
2004	50.57
2005	50.62
2006	55.81
2007	65.2

60. Not all the rates were obtainable from Transpower information material, and estimates have been made for the years ending 2000 and 2001.

Phase 4: 2008 to 2013 – Regulation

61. The failure of the New Zealand electricity industry to agree on a self-regulating rulebook led to the establishment of the Electricity Commission in 2003 and the introduction of the rules for Transmission (part F of the EGRs). The introduction of the EGRs led to significant changes in how Transpower obtained approval for its TPM.

62. The TPM applicable from 1 April 2008 to 2013, which was approved by the Minister in 2007, is the culmination of the regulatory process which was set out in part F of the EGRs and which is now contained in Part 12 of the Electricity Industry Participation Code (Code) administered by the Electricity Authority (EA).

63. The main differences from the previous TPM are:

(a) Connection charges:

(i) the introduction of the replacement cost of assets adjusted to preserve the last optimised values and a revised definition of connection assets. With the Grid Investment Test (GIT) providing for efficient investment, valuation can move away from ODV and the use of replacement costs provides the most practical and stable price path;[24]

(ii) allocation of shared connection assets is based on the anytime maximum demand for offtake customers and on the anytime maximum injection for generators;

(iii) the anytime maximum demand/injection is the average of the 12 highest values for the capacity measurement period for the relevant pricing year.[25]

(b) Interconnection charges:

(i) the costs of interconnection assets are allocated to offtake customers by using their average regional coincident peak demand (RCPD). The RCPD is designed **to give a locational pricing signal for load management and new investment; (emphasis added)**

(ii) the average RCPD is calculated using the following number of peaks (N) in the following regions:

a) In the Upper NI / Upper SI, N=12; and

b) In the Lower NI / Lower SI, N=100.

(iii) a consequential effect of the introduction of RCPD charging is the aggregation of multiple points of connection for the purpose of determining a customer's maximum demand charges;

(iv) the interconnection charges for a pricing year are fixed on the basis of the RCPD for the previous capacity measurement period. This results in lower transaction costs, facilitates the pass-through of transmission costs by distribution owners, and makes the charges more fixed and unavoidable; [26]and

(c) HVDC revenue requirement is allocated to South Island injection customers on the basis of historical anytime maximum injection (HAMI). The allocation method

[24] Transmission Pricing Methodology, Supplementary Material, Transpower New Zealand Ltd, June 2006

[25] The 12 month period from 1 September to 31 August immediately prior to the commencement of the pricing year, which is the period from 1 April to 31 March in respect of which Transpower calculates its prices

[26] Transmission Pricing Methodology, Supplementary Material, Transpower New Zealand Ltd, June 2006

uses the historical anytime maximum injection over the most recent and the four preceding capacity measurement periods. This reduces incentives to avoid HVDC charges.[27]

64. The changes were introduced to:

(a) improve the definition of connection assets and the change in the method of valuing of assets, which were addressed in the revised connection charge process;

(b) provide for locational price signals to encourage efficient investment, which was addressed by the RCPD charge;

(c) reduce the avoidability of HVAC charges, which was achieved by basing charges on the demands measured in the capacity measurement period;

(d) reduce the avoidability of HVDC charges, which was achieved by the introduction of HAMI.

65. Table 7 summarises the changes to the transmission pricing over the period 2008 to 2013.

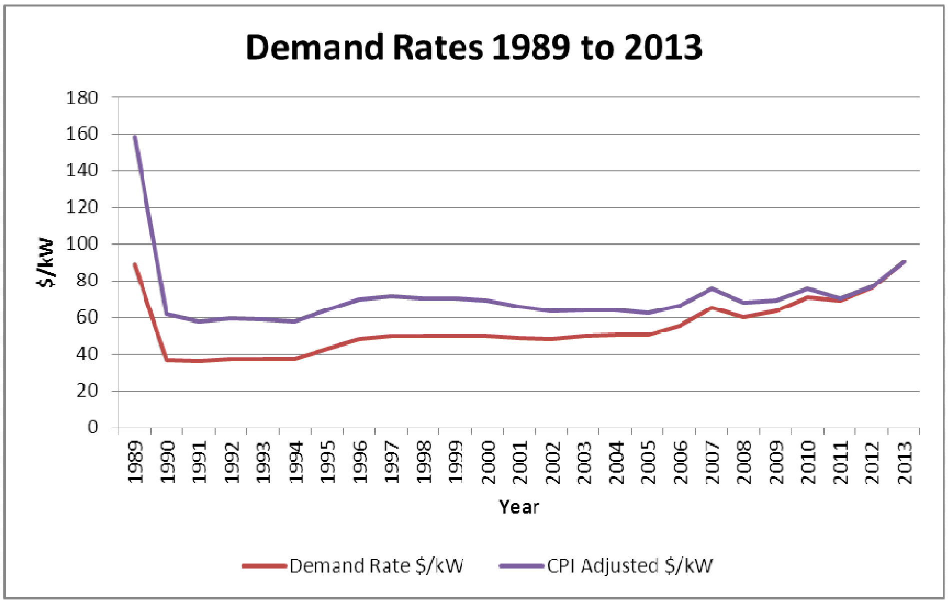
Table 7: Rates for interconnection charges 2008 to 2013

Year Ending 31 March	Demand Rate $/kW
2008	60.45
2009	63.74
2010	70.94
2011	69.12
2012	76.14
2013	90.66

66. Figure 5 summarises the trend in demand rates over the whole period from 1989 to 2013.

[27] *Ibid*.

Figure 5: Demand Rates 1989 to 2013



67. The significant events that affected the price levels and structures over the period 1989 to 2013 were:

    (a) 1988/89 - Separation of Transmission and Energy rates started

    (b) 1996/97 - Transmission charges based on Capacity and Demand Rates introduced

    (c) 1997/98 - Access Rate replaced Capacity and Demand Rates

    (d) 1999/2000 - Interconnection charges introduced 1 April 1999

    (e) 2008/2009 – Regional Coincident Peak Demand pricing introduced for interconnection charges.

68. A summary of the demand rates over the period from 1954 to 2013 is contained in Appendix 2

Investment driven by pricing signals

69. This section examines the impact of the electricity pricing signals on grid-connected consumers and how the different structures influence investment decisions.

Load Management

70. The consumption restrictions introduced during the war years saw the imposition in 1943 of a requirement on home owners in the North Island to install thermostats on new and repaired domestic hot water heaters.[28] By 1944 it became compulsory for the supply authorities to meter all hot water services to enable them to monitor usage during rationing. In the 1950s supply authorities were beginning to install ripple control relays on hot water supplies, which enabled remote control of hot water load.[29]

71. The 1950s was the period when NZ was recovering from the Second World War and trying to cope with a booming economy and an under-strength infrastructure. Electricity was rationed, not by price, but by decree and the industry had to cope with growth in demand and supply shortages.

72. The nature of the tariffs applicable over the period 1954 to 1988 led primarily to supply authorities being incentivised to reduce their electricity costs by controlling the kW demand they imposed on the power system. The use of ripple control for rationing water heating was an obvious tool for reducing demand charges while maintaining supply for other purposes.

73. The supply authorities had to introduce their own pricing signals in order to influence their consumers to optimise the use of the electricity available from the State or their own generation, or both. One method was to price electricity for controlled water heating at a lower rate than uncontrolled electricity, or simply to require consumers with electric water heating to have their water heating controlled.

74. Load control of hot water systems became necessary as part of managing supply shortages. However, investment in ripple control systems continued after the bulk supply had been reinforced and rationing finally ceased in 1958.

75. Figure 6 below shows the age of ripple control plants that were operating in 2004.[30] This can be used as a proxy for the rate of installation of ripple control systems from the early 1950s to 2004. It assumes that no plants were decommissioned over the period

76. The separation of line and energy functions on Power Companies in 1999 saw the separation of the responsibilities for ripple control transmission plant and receivers, in many networks, with Distributors generally being the owners of the transmission plant and retailers either owning or leasing receivers.

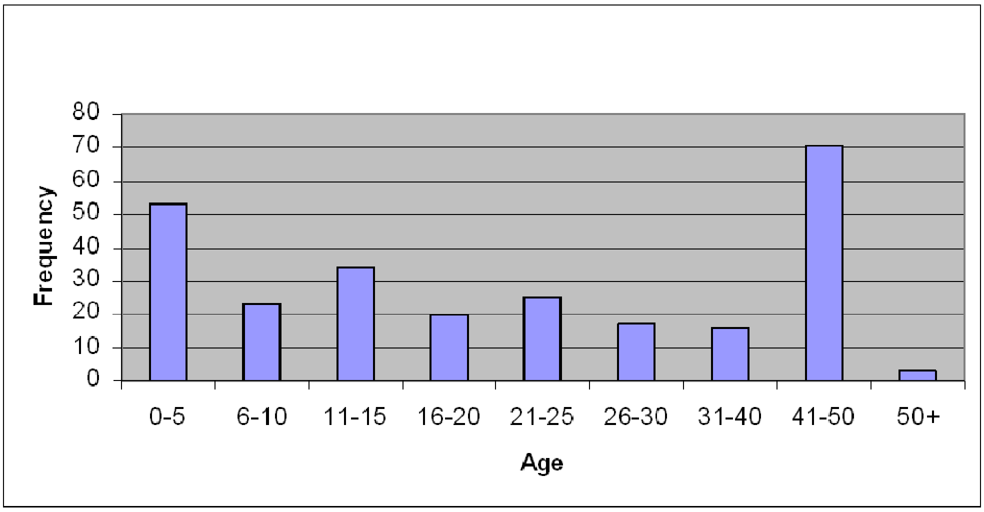
[28] The Electric Water-heating Order of July 1943 – see Reilly p 107

[29] Reilly p.107.

[30] Enermet Ltd, 2004.

77. In 2004 there were 259 plants in service with approximately 90 being installed prior to 1974, 118 between 1974 and 1999, and 51 between 1999 and 2004.

Figure 6: Age of Ripple Control Plants



78. In 2004, Enermet provided the following information regarding the number of receivers installed in NZ

(a) Number of load control receivers : 1,500,000

(b) Estimated total controllable load in NZ: 1200MW

79. A project carried out by the Electricity Commission reported in 2006 that Distributors were maintaining and upgrading ripple control plants and retailers were installing or renting control devices and had intentions to continue.[31] The primary reason for ripple control usage by the Distributors was for peak load control to avoid transmission demand related charges. Other uses included deferment of network capital expenditure, emergency load management and tariff switching.

80. The report estimated that the peak load reduction was of the order of 880MW.

81. There has been, and there continues to be, substantial investment in load management equipment related to avoidance of peak load charges. That investment has deferred the generation plant and network infrastructure that would have been required to meet an estimated additional 880MW of load.

Distributed Generation (DG)

82. The EA's working paper on ACOT provides a comprehensive review of the development of distributed generation and contains statistics relating to the numbers and types of embedded generating stations.[32] Not all of these installations received payments for avoided cost of transmission charges. Some are owned by distributors, some are probably not being used to reduce peak demand charges and others are relatively

[31] The Existing Capability Working Panel (ECWP)

[32] *Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation*, Electricity Authority, 19 November 2013 Appendix C.

small and would not qualify. The total installed capacity of a subset of the embedded generation that the EA considered significant is in the region of 850MW.[33]

83. The paper also provides information on the installed capacity for which payments were made over the period 2008 to 2011[34]. It estimates that approximately $50 million will be paid to 766 MW of qualifying generation during 2013/14.

84. As shown in Figure 1 of this paper there was a considerable proportion of the early supply authorities that had to install their own generating plant to initiate electricity supply to their regions. Some of those generating stations still exist[35] and provide some security of supply benefits and can be used to reduce costs arising from transmission charges or earn revenue from the wholesale electricity market.

85. There was group of 13 stations totalling 145 MW which were constructed by supply authorities prompted by the local hydro scheme provisions included in the 1977 New Zealand Government Budget. These stations were built to increase local electricity self-sufficiency and were commissioned in 1980 or 1981[36]. Similarly, these stations can be used for security of supply purposes, to avoid transmission charges or earn revenue.

86. Between 2000 and 2010, DG capacity increased from 485 MW to 666 MW (an increase of 181 MW) and this additional capacity will provide the same benefits. The level of the pricing signal for avoiding transmission charges has increased in nominal terms from $50/kW in 2000 to $90.66/kW in 2013.

[33] *Ibid* Table 2

[34] *Ibid* Appendix A

[35] Monowai and Waipori would be examples

[36] *Ibid* Table 3 and Rennie p205

Appendix 1

Bulk Supply Tariff to 1988[37]

[37] Extracted from the appendix to *A History of Wholesale Electricity Pricing" From April 1987 to September 1996,* Internal Electricity Corporation of New Zealand (ECNZ) Report, April 1997.

Bulk Supply Tariff Summary[38]

Year ended 31 March

1914/15	Contract with Christchurch City Council		
	First	300kW	$17.33 per annum
	Over	300kW	$10.00 per annum

Information about changes before 1933 has not been compiled for this report.

		kVA	Per Quarter
1932/33	First	200	$5.00
	Next	4,800	$4.00
	Next	15,000	$3.50
	Over	20,000	$2.625
1940/41	First	200	$5.00
	Next	4,800	$4.00
	Next	12,000	$3.50
	Over	17,000	$2.625
1948/49	First	200	$5.00
	Next	9,800	$4.00
	Next	15,000	$3.50
	Next	45,000	$3.00
	Over	70,000	$3.25
1953/54	First	200	$6.00
	Next	19,800	$5.75
	Next	30,000	$5.25
	Over	50,000	$5.45
1958/59	(a) State Supply of Elec. Energy Amend. Act 1957, effective 1/4/58 - price charged to be calculated to produce 25% more than expenses of management, operation and maintenance incl. depreciation and interest but not including loan repayments. Surplus revenue to be applied firstly to reduction of capital liability and secondly to credit of the Reserve Fund.		
	(b) State Supply of Elec. Energy Amend. Act 1958 deferred this capital contribution until 1/4/59.		
	(c) Tariff from 1/4/58: $8.50 per kW per quarter less 50 cents if reduction passed on to domestic consumers.		

[38] Originally compiled 16 May 1979. Updated and issued by: Commercial Operations, Electricity Corporation of NZ Ltd.,15 May 1987

1959/60	Section 2 of State Supply of Elec. Energy Amend. Act 1959 postponed capital contribution until 1/10/60.
1960/61	Section 2 of State Supply of Elec. Energy Amend. Act 1960 postponed capital contribution until 1/10/61
1961/62	Tariff from 1/10/61: $8.50 per kW per quarter
1967/68	State Supply of Elec. Energy Amend. Act 1965 changed the capital contribution to "25% or such other percentage not exceeding 50% as the Minister of electricity and the Minister of Finance after consultation with the Electrical Supply Authorities Assn. determine." New tariffs adopted: (a) From 1/4/67 to 30/9/67 (estimated to yield 25% capital contribution): $19.80 per kW per annum plus 0.225 cents per kWh. (b) From 1.10.67 (to yield 50% capital contribution - approved by Cabinet - CM 67/8/28 of 13/3/67): $23.50 per kW per annum plus 0.27 cents per kWh. **Effective charge for year**: $21.65 per kW per annum plus 0.27 cents per kWh Note: Contract period was 1/10/67 to 31/3/72. Because of an action by the Government of the day tariff (b) remained in force until 31/3/76.
1976/77	from 1/4/76 to 31/3/77: (60% increase) $29.21 per kW per annum plus 0.61 cents per kWh Note: Revenue derived from peak charge and energy charge was changed from a ratio of 2 peak: 1 energy at .50 L.F. to 1 peak: 1 energy at .55 L.F
1977/78	from 1/4/77 to 31/3/78: (40% increase) $40.89 per kW per annum plus 0.85 cents per kWh
1978/79	1/4/78 t0 31/4/79: (5% increase) $42.93 per kW per annum plus 0.89 cents per kWh (Tariff in operation for 13 months - see below)

1979/80	Originally proposed as 5% increase which equals $45.08 per kW per annum plus 0.93 cents per kWh. Later amended to:from 1/5/79 to 31/3/80: (60% increase) $68.60 per kW per annum plus 1.42 cents per kWh.		
1980/81	from 1/4/80 to 31/3/81: (6% increase) $72.81 per kW per annum plus 1.51 cents per kWh		
1981/82	from 1/4/81 to 31/3/82: (9% increase) $79.36 per kW per annum plus 1.65 cents per kWh		
1982/83	from 1/4/82 to 31/3/83: (12% increase) $88.88 per kW per annum plus 1.85 cents per kWh		
1984/85	from 1/4/84 to 31/3/85 : (4% increase N.Z)		
		North Island	South Island
	Winter zone demand	$57.88 per kW per annum	$54.60 per kW per annum
	Anytime demand	$16.78 per kW per annum	$15.83 per kW per annum
	Day rate energy	2.443 cents per kWh	2.305 cents per kWh
	Night rate energy	1.995 cents per kWh	1.844 cents per kWh
	Increase	6%	-
1985/86	from 1/4/85 to 31/3/86 : (25% increase N.Z)		
	Winter zone demand	$73.16 per kW per annum	$66.50 per kW per annum
	Anytime demand	$21.21 per kW per annum	$19.28 per kW per annum
	Day rate energy	3.088 cents per kWh	2.807 cents per kWh
	Night rate energy	2.471 cents per kWh	2.246 cents per kWh
	Increase	26.4%	21.8%
	Differential between North and South Islands 10%		

1986/87	from 1/4/86 to 31/3/87 : (12.0% increase N.Z) excluding 10% GST (from 1 October 1986) Note: GST applicable ONLY to ENERGY and any ANYTIME DEMANDS recorded On or AFTER 1 OCTOBER 1986.		
		North Island	South Island
	Winter zone demand	$84.50 per kW per annum	$69.16 per kW per annum
	Anytime demand	$24.50 per kW per annum	$20.25 per kW per annum
	Day rate energy	3.567 cents per kWh	2.919 cents per kWh
	Night rate energy	2.854 cents per kWh	2.336 cents per kWh
	Increase	15.5%	4.0%
	Differential between North and South Islands 22%		
1987/88	from 1/4/87 to 30/9/87 : (9% increase N.Z) The level of the bulk supply tariff will be reviewed during 1987 taking account of the current negotiations between the Government and the Electricity Corporation of N.Z. Limited Depending on the outcome of these negotiations, the values of the energy components quoted below may be altered at any time after 1 October 1987.		
	Excluding 10% GST		
		North Island	South Island
	Winter zone demand	$92.10	$75.38 per kW per annum
	Anytime demand	$26.70	$21.85 per kW per annum
	Day rate energy	3.888 cents	3.182 cents per kWh
	Night rate energy	3.111 cents	2.546 cents per kWh
	Increase	9%	9%
	Differential between North and South Islands 22%		

The structure of the four-part bulk tariff from that applied form 1 April 1984 is as follows, on an annual basis:

Winter Zone Demand - the average of the 6 combined demands on Electricorp incurred between 0700 and 2300 (i.e. half hours ending 0730 and 2300 respectively) on any day between 15 May and 15 September inclusive with a maximum of 1 demand being chargeable on any one day.[39]

Anytime Demand - the average of the highest 6 combined demands on the Electricorp occurring at any time and on any day of the year with a maximum of one demand being chargeable on any one day (these demands may or may not coincide with the chargeable winter zone demands).

Day Rate Energy - for all consumption between 0700 and 2300 inclusive (i.e. half hours ending 0730 and 2300 respectively) on all days of the year.

Night Rate Energy - for all consumption between 2300 and 0700 inclusive (i.e. half hours ending 2330 and 0730 respectively) on all days of the year.

The items specified here are to be altered for the duration of the transition period for those previously on the three-part tariff.

For those authorities concerned the chargeable peak period will progressively widen from the coincident zone period to the four-part tariff zones as follows:

1984/85 chargeable winter zone demands will be in the periods 0800 to 1000 inclusive (half hours ending 0830 to 1000 inclusive) and 1700 to 2000 inclusive (half hours ending 1730 to 2000 inclusive) Monday to Friday only from 15 May to 15 September inclusive.

1985/86 chargeable winter zone demands will be in the periods 0800 to 1100 inclusive (half hours ending 0830 to 1100 inclusive) and 1730 to 2100 inclusive (half hours ending 1730 to 2100 inclusive) Monday to Friday only from 15 May to 15 September inclusive.

1986/87 chargeable winter zone demands will be in the periods 0700 to 2300 inclusive (half hours ending 0730 to 2300 inclusive) Monday to Friday only from 15 May to 15 September inclusive.

All the times given above are NZ Standard Time or NZ Daylight Saving Time when this applies (as per the Time Act 1974).

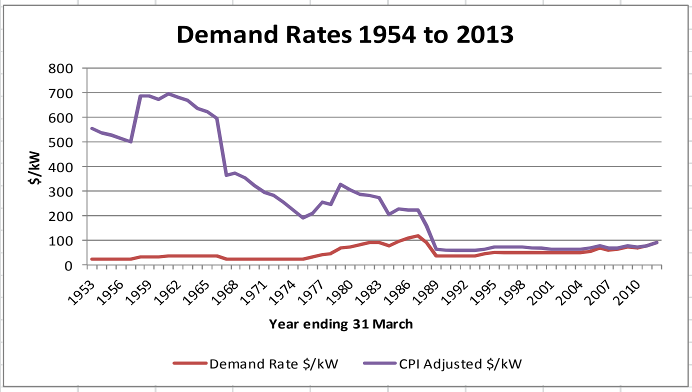
[39] This would have been the average of the 6 highest demands recorded in the period with a maximum of 1 demand being chargeable on any one day

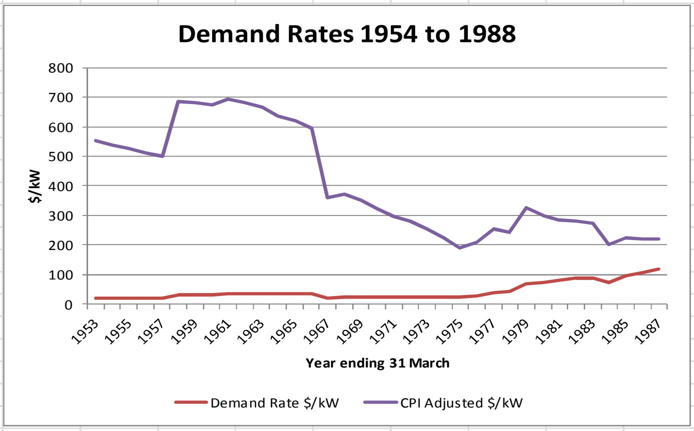
Appendix 2

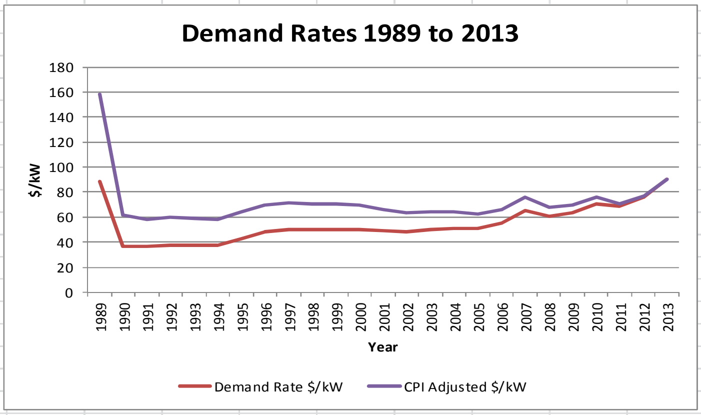
Pricing signals from 1 April 1954 to 31 March 2013

Pricing signals conveyed by demand rates to grid connected consumers over the period 1954 to 2013

Year Ending 31 March	Demand Rate $/kW	CPI March Quarter	CPI Adjusted $/kW	Notes
1953		44		10
1954	21.8	46	553	
1955	21.8	48	537	
1956	21.8	49	526	
1957	21.8	50	512	
1958	21.8	51	498	
1959	32	55	686	
1960	32	55	683	
1961	32	56	672	
1962	34	58	694	
1963	34	59	681	
1964	34	60	665	
1965	34	63	637	
1966	34	64	619	
1967	34	67	594	
1968	21.65	71	360	3
1969	23.5	74	371	
1970	23.5	78	354	
1971	23.5	86	321	
1972	23.5	93	296	
1973	23.5	99	279	
1974	23.5	109	253	
1975	23.5	123	224	
1976	23.5	145	191	
1977	29.21	164	209	4
1978	40.89	188	255	
1979	42.93	208	242	
1980	68.69	246	328	
1981	72.81	284	301	
1982	79.36	328	284	
1983	88.88	370	282	
1984	88.88	383	273	
1985	74.66	434	202	5
1986	94.37	490	226	
1987	109	580	221	
1988	118.8	632	221	8 and 12
1989	88.8	658	159	6 and 11
1990	37	704	62	11
1991	36.4	736	58	11
1992	37.6	741	60	
1993	37.6	749	59	
1994	37.6	758	58	
1995	43	789	64	1
1996	48	806	70	1 and 11
1997	50	821	72	7
1998	50	831	71	2
1999	50	830	71	
2000	50	843	70	2 and 9
2001	49	869	66	2
2002	48.36	891	64	
2003	50.18	913	64	
2004	50.57	928	64	
2005	50.62	953	62	
2006	55.81	985	67	
2007	65.2	1010	76	
2008	60.45	1044	68	
2009	63.74	1075	70	
2010	70.94	1097	76	
2011	69.12	1146	71	
2012	76.14	1164	77	
2013	90.66	1174	91	







Sources:

1953 to 198	Bulk Supply Tariff Summary updated and Issued by ECNZ May 1987
1987 to 199	A History of Wholesale Electricity Pricing from April 1987 to September 1996 - ECNZ April 1997
1996 to 201	Transpower Pricing Booklets - 1996, 1998, 1999, 2002,2003 2004,2005, 2006,2007 2008, 2009, 2010, 2011,2012

Notes:

1	ECNZ only published Transmission related charges from 1990 to 1994; Rates from 1995 and 1996 are estimated
2	Transpower rates for 1998, 2000 and 2001 have been estimated
3	1967/68 - Demand rate reduced and kWh rate introduced
4	1976/77 - kWh rate increased
5	1984/85 - Seasonal and TOU Rates introduced
6	1988/89 - Separation of Transmission and Energy rates started
7	1996/97 - Transmission charges based on Capacity and Demand Rates
8	1997/98 - Access rate replaced Capacity and Demand Rates
9	1999/2000 - Interconnection rates introduced 1 April 1999
10	CPI SE9A - Statistics New Zealand March quarter. Used for adjusting each year
11	Years ending 31 October
12	Years ending 30 April