

Submission to
Minister of Energy

Electricity: Post Winter Review

Executive summary

Contributing Factors:

- Electricity shortages are a historical reality in New Zealand due to hydro-dependency and small storage capacity.
- The issue is therefore how to manage, not whether there will be, shortages in future.
- Hydro conditions in 2001 were unusually severe, with record low inflows
- Demand growth was significant through late 2000 and early 2001
- These two factors placed the electricity system under great physical stress.

How Effective Was the Market?

- Physical performance:
 - current arrangements ensured that “the lights stayed on”, the key test;
 - rising spot prices prompted significant demand reductions and increased supply.
- Financial performance:
 - spot prices tracked the costs associated with various alternatives to hydro generation (e.g. thermal generation./demand reduction) employed during the winter.
- Hedge contract availability:
 - hedge contracts were available from Contact throughout the period;
 - some major consumers declined hedges priced at competitive rates;
 - spot prices were relatively low in the previous three winters. This appears to have contributed to purchasers under-hedging;
 - most customers were shielded from high spot prices by fixed price contracts.
- Generator/retailers with balanced portfolios were best placed to shield consumers from the risks of price volatility.

Suggestions for Change to Market Arrangements:

- Current market arrangements promote transparency for spot market prices.
- However, information about the hedge market, i.e., future prices, is less transparent.
- Options under active consideration to improve transparency:
 - publication of key parameters of signed deals;
 - publication of “benchmark” hedge prices;
 - greater participation in the existing futures market.
- Lines company contracts are widely divergent and require national standardisation to facilitate competition in retail electricity provision.
- Contingency planning should be improved by:
 - allowing fast-tracked relief of transmission system constraints;
 - further development and marketing of interruptible contracts;
- The transmission rentals system should be reformed.

What Changes Would Improve Energy Efficiency and Conservation Campaigns?

- Government involvement was useful.
- Advance preparation of “off the shelf” conservation campaigns should be promoted.
- Diversity of campaign styles among retailers and generators fosters creativity.

Future Outlook

- Generation constraints are emerging more quickly than earlier anticipated.
- Regulatory certainty remains a pre-condition for timely investment in new generating capacity.
- New generating plant will require somewhat higher average prices than prevail at present to justify investment.
- Notwithstanding this, New Zealanders are now paying, and for the foreseeable future will continue to pay, among the lowest prices for electricity in the developed world.

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What factors contributed to wholesale market developments in the 2001 winter?

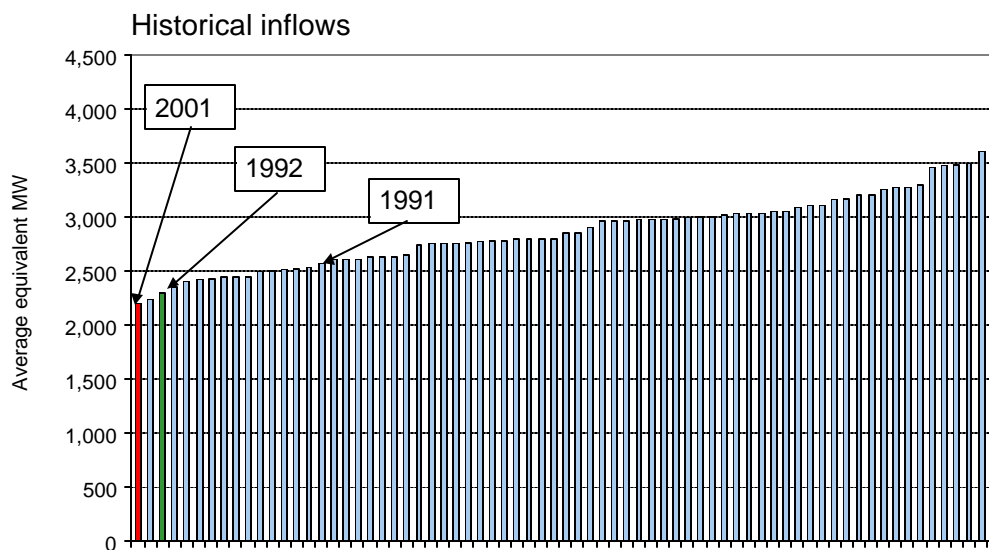
The tight market conditions experienced during the winter of 2001 had two key underlying causes, both of which are physical in nature – extremely dry hydrological conditions and strong demand growth.

Hydrological conditions

Inflows are the mainstay of New Zealand's electricity generation

Hydro inflows are the mainstay of New Zealand's electricity generation industry. Hydro generation accounts for 60-70 percent of electricity production, and maximum hydro storage is only 4,500 GWh, or 13 percent of annual consumption. As a result, New Zealand cannot rely on stored water to maintain generation, and is very dependent on regular inflows into its hydro catchments.

2001 has been an extremely dry year. Indeed, for the period 1 January – 1 August, national inflows were the lowest in 71 years of record keeping. They were 22 percent lower than mean, and lower even than those experienced in 1992, when New Zealand last experienced a major 'hydro generation' drought. This is clearly evident in the chart below.



National inflows for January – July were the lowest in 71 years of records

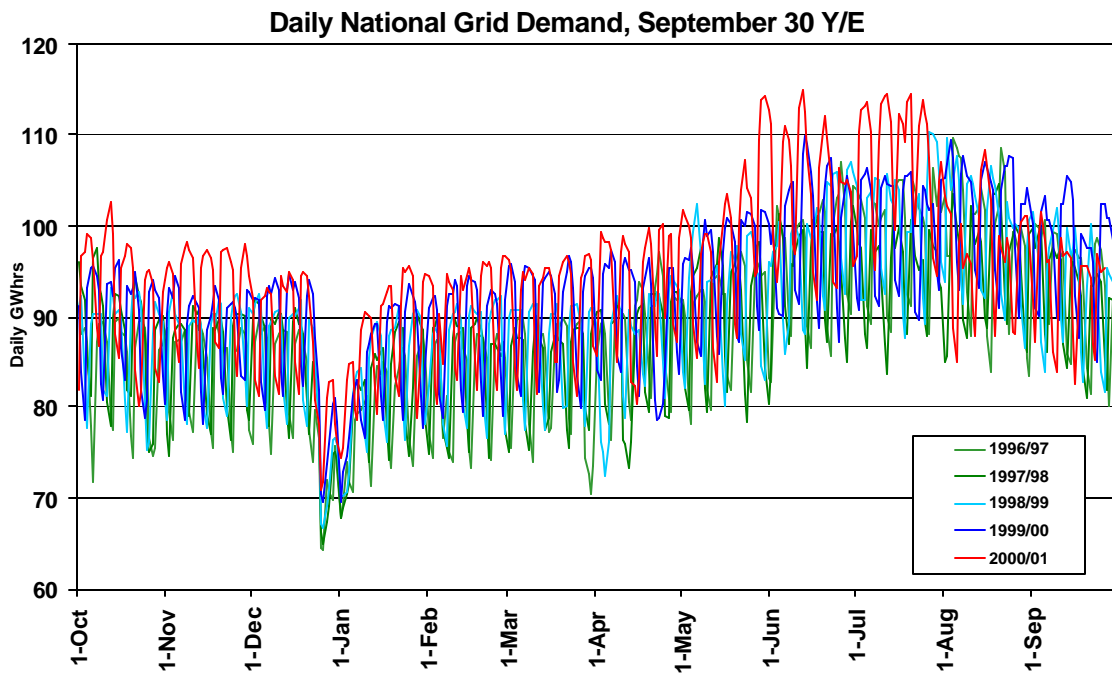
Source : Infratil data

Demand growth

The supply constraint imposed by low inflows was compounded by a significant increase in demand experienced this winter.

Supply pressure was reinforced by surging national electricity demand in June and July

In aggregate terms, demand for the June-July period (i.e. excluding the period when demand reduction measures were starting to have a major impact) was 5.8 percent higher than the same period in 2000. This compares with average growth in grid demand of 3.2 percent over the previous four years.



Source : NZEM data

Demand peaks for winter 2001 were both high, and unusually early

This winter's demand growth is illustrated above in the chart depicting daily grid offtake. The track for 2001 (shown in red) is compared with each of the previous four years. Three features are particularly apparent. First, demand growth has been strong since October 2000. Second, the peaks for 2001 are significantly above those for the previous years. Finally, the onset of demand peaks was very early this winter, occurring from the last week of May, rather than the more normal period of late July.

The early and high demand peaks had particular significance at the time because it was not known then whether they presaged an even higher demand peak later in winter (meaning a much higher average demand track), or were simply the result of unseasonably cold weather.

Combined impact of low inflows and increased demand

The combined impact of reduced inflows and demand growth was very significant. Dry conditions reduced inflows by approximately 1,800 GWh for June-August 2001 compared with the previous year. Demand growth added around 580¹ GWh of load for the same period. Combined, these influences amounted to nearly 2,400 GWh.

To put this into context, events that would provide an equivalent level of stress to the electricity system would be:

Low inflows and high demand put the system under great stress

- the complete loss of all nine of the hydro stations on the Waikato river for the period
- the loss of half of New Zealand thermal generation stations (e.g. Huntly and Te Rapa)
- additional demand appearing equivalent to a 'new' Auckland

¹ Actual for June and July, with projection for August based on trend for previous two months

How effective were the existing market arrangements in responding to these developments?

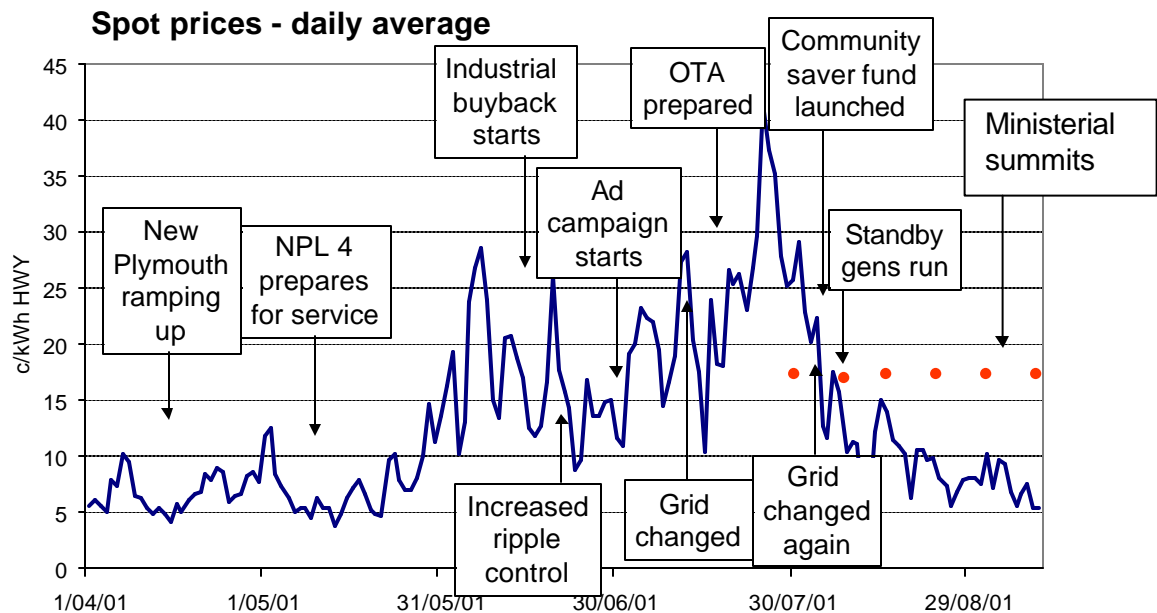
The effectiveness of the existing market arrangements is best judged by considering the outcome of this winter in terms of physical impact, and separately in terms of financial performance.

Physical performance

The market kept supply and demand in balance – the lights stayed on

The most basic test of any set of arrangements to produce and deliver electricity must be whether there were any involuntary supply interruptions. Based on this measure, the current set of arrangements has performed well. In other words, the lights stayed on. This is despite the system being subjected to a great deal of physical stress.

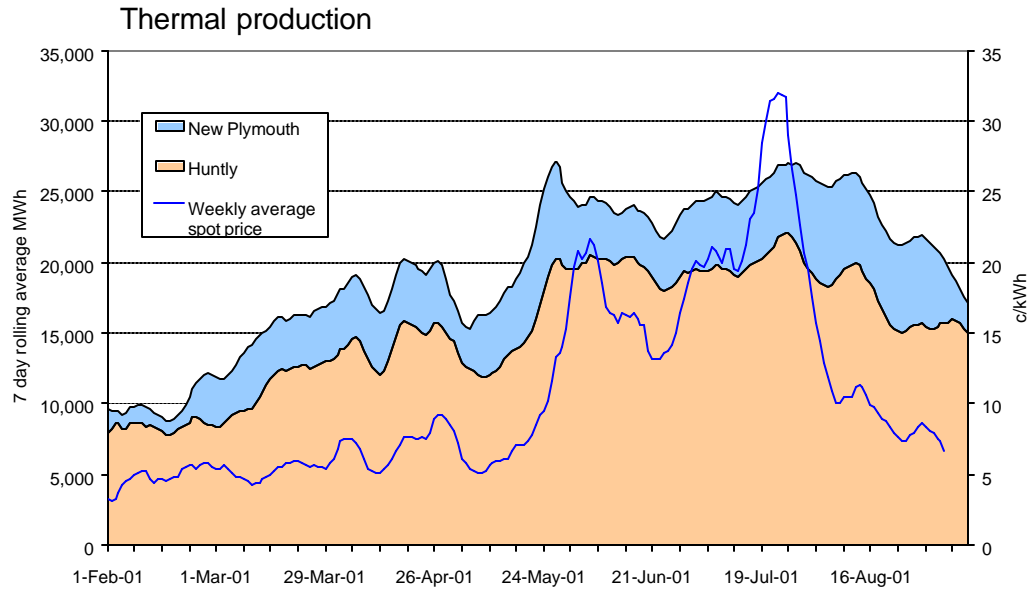
Fundamentally, the reason the system continued to balance demand and supply was that spot prices rose to levels that elicited a strong supply response, and subsequently as prices rose further, they also prompted significant demand reductions. The sequence of responses that directly involved Contact is illustrated below.



Source : NZEM data

The strength of the supply response can be gauged by looking at generation from Huntly and New Plymouth (the only significant non-baseload thermal stations). Their production rose sharply in March when, after an extended period of low inflows, lake levels dipped below mean, and spot prices rose to around 5c/kWh. Production continued at this general level until late May when prices rose sharply with the onset of much higher demand, and further deterioration in lake levels. This is shown in the following chart.

Thermal production increased strongly with higher spot prices

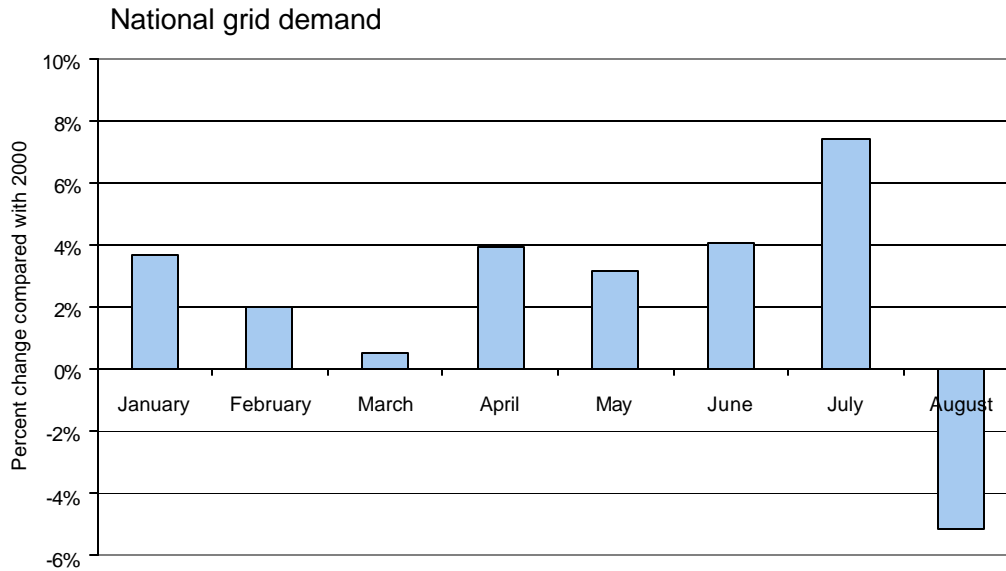


Source : NZEM data

The sharp rise in spot prices at the end of May created strong signals to conserve electricity. These signals acted on all participants with exposure to spot prices. The demand response took a number of forms including:

- *Demand cutbacks by customers exposed to spot prices* – e.g. by large users closing plant or temporarily reducing production
- *Industrial buybacks* – retailers (such as Contact) paid customers to temporarily shut plant, or use their diesel standby generation, to reduce the retailers' exposure to spot prices
- *Retail buybacks*- there were a variety of schemes encouraging domestic users to 'power down' in return for direct monetary benefits or donations to community or national causes
- *Increased use of ripple control* – given that water heating accounts for approximately 40% of household demand, this was important in managing energy loads

Demand reacted sharply to high spot prices – though with a lag



Source : Contact estimates

Because demand response measures involve a host of parties, they tend to be more complicated to arrange, and require more lead time. Nonetheless, there is strong evidence to show that the combined demand savings during the latter part of the winter were significant as shown above. Without timely price signals, this winter's shortages would almost certainly have been more severe and difficult to manage.

Financial impact

While the existing arrangements were effective in ensuring the lights stayed on, some have questioned whether prices became unnecessarily high, and whether parties had effective means to protect themselves from high spot prices.

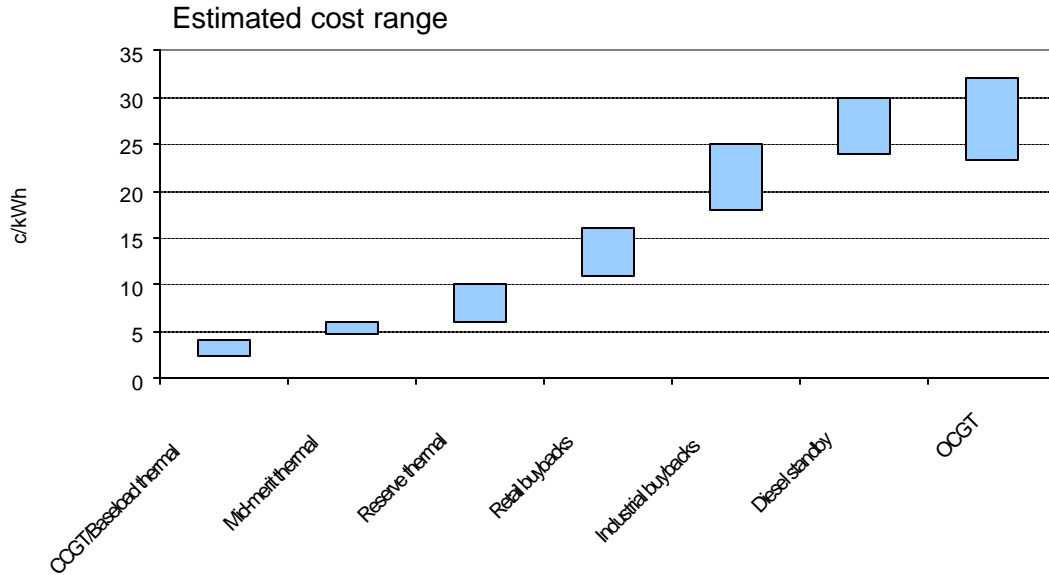
In a well performing electricity spot market, one would expect to see spot prices that broadly reflect the cost of providing each increment of generation or demand reduction. In making an assessment on this issue, it is important to note that spot prices should take account of direct costs, and any indirect or opportunity costs arising from a decision to increase generation or reduce consumption.

The following chart shows the estimated cost for a variety of generation and demand reduction sources.

Conventional plant runs below 5c/kWh

Mid-merit thermal runs between 5-10 c/kWh

Buybacks and diesel plant are not economic until prices rise above 10c/kWh



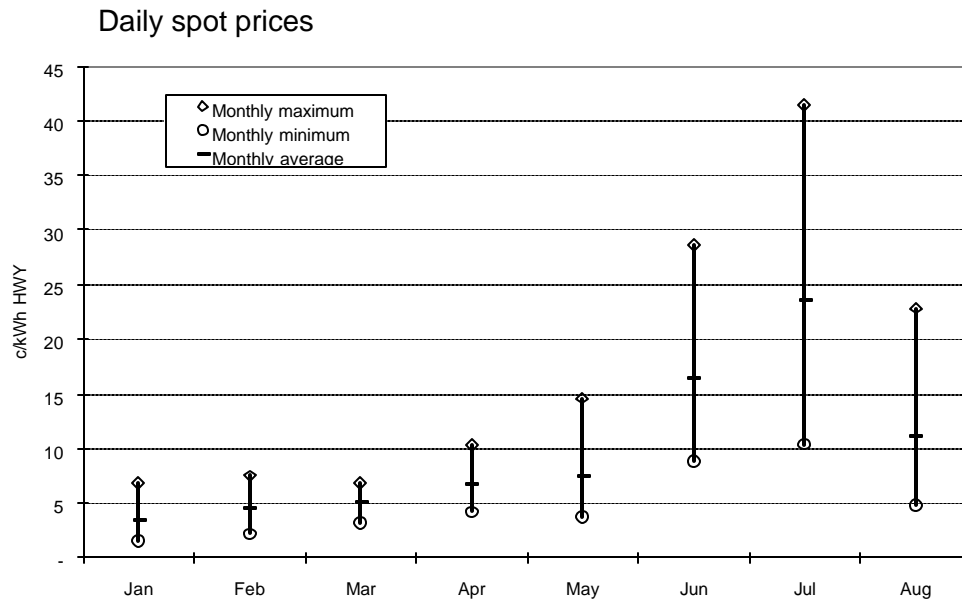
Source : Contact estimates

Conventional plant constrained prices in Jan-Feb

Mid-merit thermal set price when it became dry

As shortage worsened, prices reflected cost of demand reduction and stand-by diesel generation

The following chart shows the high low and average prices for each month.



Spot prices reflected cost of generation and/or demand reduction measures for each phase of the shortage

There is a consistency between the chart depicting cost ranges (showing what should happen when the market is tight) and the track of actual prices. In essence:

- During January – February spot prices averaged below 5 cents/kWh – hydro conditions were close to normal and demand was met from conventional generation sources;
- During March – May hydro conditions gradually worsened and spot prices steadily climbed through the period, averaging between 5-10 c/kWh. During this period thermal generation was increased progressively in response to higher spot prices. Prices were generally constrained by recall of stored thermal capacity. These units require 6-10 c/kWh to be worth running as this

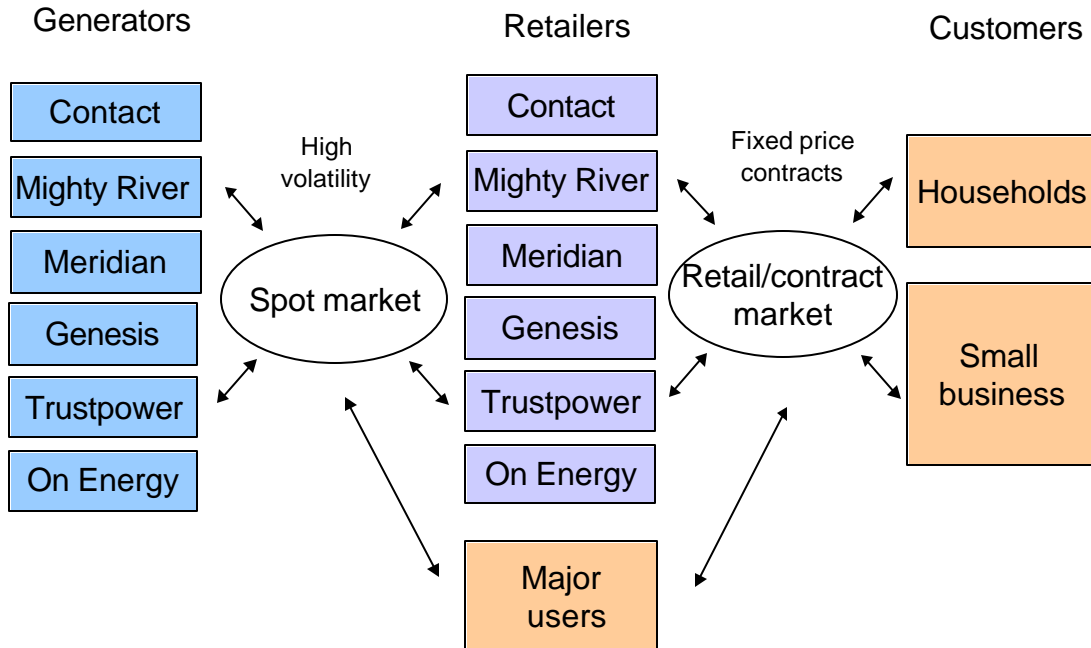
capacity is old, relatively inefficient, and has significant recall costs. The cost of fuel can also be higher because it is not economic to maintain firm contracted supplies for such plant.²

- During June-August demand could not be met solely through the recall of conventional thermal units which were running to full capacity. Instead, demand reduction mechanisms (e.g. buybacks) and diesel fuelled plant acted as the main restraint on prices – these options are economic in the range 11-32 cents/kWh. This compares with actual monthly averages between 11-24 c/kWh.

In short, there appears to be reasonable evidence to indicate that spot prices (at least in average terms) broadly reflected the costs of providing additional increments of generation or demand reduction.

Could customers hedge against spot market volatility?

The other related issue is whether customers have effective means to protect themselves from exposure to volatile spot prices if they wish. The diagram below summarises the present market structure.



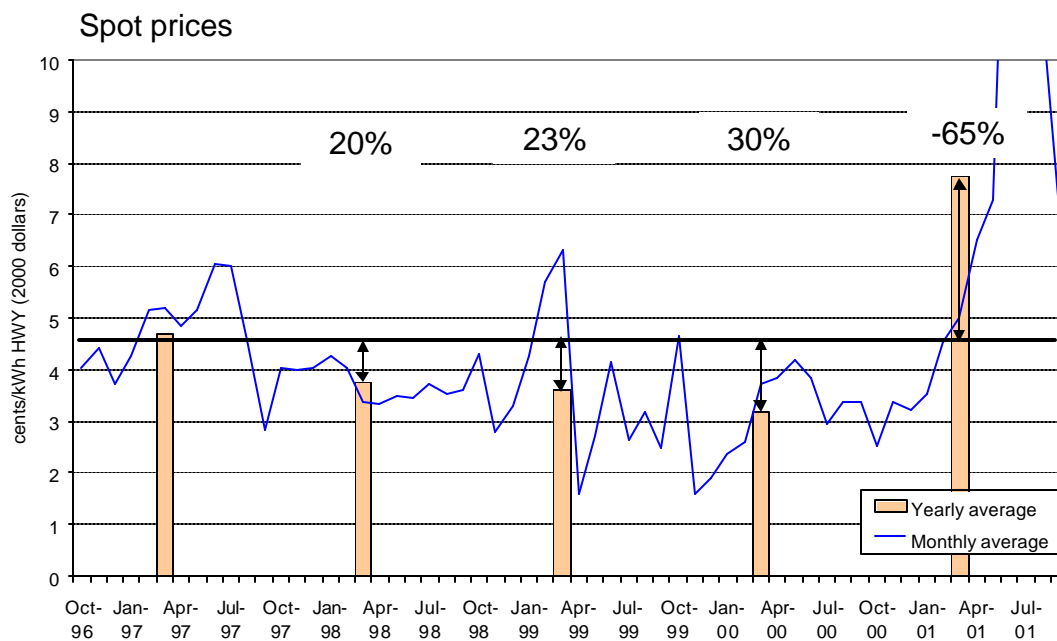
Most end users were shielded from spot volatility by fixed price contracts

The first point to note is that very few end use customers buy out of the spot market – the vast majority of sales by number and volume is conducted through fixed price contracts of varying terms. Indeed, aside from the major retailer/generators, who all stood on both sides of the spot market, the only parties with any significant exposure to the spot market appeared to be a group of larger industrial customers³.

² For example, over mid August to mid September, we understand there was no more gas available for thermal generation than that actually used. It appeared also that there was no unutilised coal based thermal generation capacity over that period. The only means of obtaining additional gas deliverability was from non-generation sources. That would have involved a significant cost penalty.

³ Having said that, there were a some smaller end use customers who were on fixed price contracts, but who faced a renewal or contract termination during the period, exposing them to spot price. We understand that some of these terminations are being challenged in the Courts.

While these customers were undoubtedly feeling financial pain from the high spot prices, this needs to be weighed against the benefits that were accrued in earlier years from buying at spot prices that were on average lower than contract prices. Indeed, compared to the opening year of the wholesale market in 1996, spot prices fell by 20-30% reflecting abundant supply and a series of mild winters.



Source : Contact estimates. 2001 data is to mid Sept

Are there enough hedges to go around?

Generators wish to sell hedges, and end-users wish to buy them

As noted earlier the New Zealand market is subject to marked changes in conditions due to hydrological volatility. This is a double-edged sword – spot prices rise in dry years (bad for buyers), and fall in wet years (bad for generators). As a result, net generators are natural hedge sellers, and retailers/end users are natural buyers.

In terms of overall production capability, the New Zealand electricity system is capable of producing around 41,000 GWh in a dry⁴ year – assuming thermal production is fully cranked up. This compares with aggregate demand of approximately 35,000 GWh. The issue appears to be more one of price expectation differing between buyers and sellers than one of capacity, and may have been exacerbated by buyers' experience of relatively low spot prices in the three preceding winters.

Contact's own experience is that hedges are available – the issue is more one of lack of consistency over price expectations

Contact's own practical experience supports the contention that hedging is available to customers. During the latter part of 2000 Contact was active in making hedge available to other parties. Indeed, as recently as November 2000 it offered a major buyer a large hedge at less than 4 c/kWh, and this offer was not taken up. We subsequently contracted with the same party in early 2001 at a price somewhat higher than that level.

Contact was even prepared to offer hedge in the midst of the winter supply shortage, provided it was fairly compensated for the risks involved. Since the winter Contact has been active again, offering 80 MW of hedge through a tender. Of the parties thought to have an interest, only 2/3 actually made offers to buy, and contracts were subsequently written with two parties for 20 MW.

⁴ Assuming a 1:10 year drought

Would it help to split generation from retail?

Some parties have argued that splitting generation away from retail would enhance risk management. We believe the opposite is true.

The risks in the New Zealand electricity system stem from physical causes:

- a high degree of hydro dependence, with variable inflows and very limited storage (<13% of annual consumption)
- a long 'stringy' transmission system that is prone to constraints and faces a risk of loss of major circuits
- a relatively small generation fleet with some large single units making it vulnerable to loss of major generators or ancillary equipment.

Integration of generators and retailers allows physical risks to be managed with least cost

Prohibiting the integration of generation and retailing will not alter any of these risks. However, it would remove the best tool for managing the risks. Integration allows some of the risks to be 'internalised' within a firm. This balancing of generation capacity and retail demand keeps the cost of risk management to a minimum.

Customers benefit from greater certainty

This was evident in the winter of 2001 when financial markets were having a lot of difficulty assessing the position of net retailers. This is because such companies were seen as having a higher risk exposure, and because it is more difficult for an outside agency to effectively monitor that firm's changing risk exposure. Fully integrated firms have a natural advantage in securing debt and equity, and in managing their risk position. That is why the fully integrated companies were able to absorb the spot volatility, rather than seeking to pass some or all of it on to their customers.

Comparison with alternatives

In assessing the relative merits of a market-based system it is useful to consider the past performance of alternative arrangements.

Until 1996 New Zealand did not rely on a wholesale market to balance supply and demand, but instead used a mixture of administrative mechanisms. The table below highlights some of the measures used to deal with hydro shortage situations under those arrangements.

Period	Issue
1942	Use of space heaters and radiators prohibited during peak hours between May and August in the North Island
1943	Space heating was controlled further, and so too were indoor and outdoor lighting
1946	20% power cuts imposed in the North Island
1947	30% power cuts imposed in the South Island
1958	A 15% cut was imposed in the North Island
1973	Supply authorities were requested to save up to 6%. Broadcasting hours were reduced, ripple control was increased and in some areas there were daily blackouts.
1974, 1975, 1976, 1977	Government requested 'voluntary' savings
1992	Large publicity campaign used to reduce demand. Water heating was generally cut for 18 hours/day, and Comalco closed one of its three potlines (= 5% of national demand)

Hydro shortages are not new to NZ

Disruption in 2001 was mild compared to some previous years

Source : Appendix 3, Report of the Electricity Shortage Review Committee 1992

What changes should be made to market arrangements, why are these changes recommended and what are the costs and benefits?

Contact believes that while the existing arrangements have worked effectively, they can be improved in a number of important respects.

Make hedge prices more transparent

Current arrangements provide a high degree of transparency for spot market prices. The market for hedges is less visible, in large part because, unlike spot electricity, hedges are not homogeneous. They are generally written to suit a specific customer, and so will reflect that party's demand location and expected load profile. Given that spot prices vary every half hour, and across the 244 nodes of the transmission network, this introduces significant variability. Further complicating factors are treatment of force majeure risk, and whether a hedge is a two-way contract, a cap, or a collar. A second important factor is that the New Zealand market is relatively small – both in terms of the overall volume and the numbers of buyers and sellers.

Nonetheless, within these constraints, we believe it is important to ensure that participants have access to up to date and meaningful information on hedge prices. At this point, the options for addressing the issue appear to be.

- *Buyers/sellers to publish key parameters of signed deals* – this would have the virtue of revealing 'real' data, but the information is likely to be of limited value because of the difficulties in comparing terms from bespoke contracts.
- *Wholesale participants to publish buy or sell prices for 'benchmark' contracts on a regular basis* – to ensure the prices were genuine, parties would need to be prepared to transact some minimum volume at those prices. This mechanism would facilitate comparisons, but to some extent would be artificial as few parties actually purchase 'benchmark' products.
- *Build on the existing futures contract market* - this facility provides information on future prices, but currently suffers from limited liquidity. However, the futures market has the virtues of an established track of prices, uses readily understood benchmarks, and reflects buyers' and sellers' actual views.

Hedge market should be more transparent

The industry is currently considering the merits of these and other options. At this point, enhancing the future contract market appears to be the best route forward.

Simplify market to encourage competition

There has been a trend towards increased regionalisation in the industry over recent years. While this is not a problem as yet, it would be a concern if it continued to a point where the market became so segmented that competition was constrained.

Fundamentally we believe there are two influences encouraging regionalisation:

- widely diverse requirements for business terms from New Zealand's 30+ network companies
- high volatility in regional pricing caused by transmission constraints, which increases the operating risk for a retailer.

Market should be simplified to encourage competition

We believe that the first of these issues is best addressed by network companies being required to offer a standard contract. The requirement under the Government Policy Statement that the industry develop a model use of system contract will help. However, this is not enough by itself. Much of the disincentive to doing business in some network areas arises from the onerous data transfer and reconciliation requirements they impose. It is also necessary to address this issue.

Regional pricing volatility arises because of the inability at certain times to transfer any more power from lower price zones to higher price areas. This problem is best tackled at its root cause, by unblocking the current impediments to worthwhile transmission investment. At present, new investment tends not to occur unless all users who will benefit from it agree to pay for it. This effectively requires unanimity, which is very difficult to achieve in practice.

The new governance rules propose a regime based on a high acceptance threshold, but which does not require unanimity. This appears much more practical, and should remove the largest blockage to new investment.

Improve contingency planning

Although there were a number of plans in place across the industry to deal with a potential shortage, we believe that the experience of winter 2001 has shown that they can be strengthened.

There are a number of areas which should be emphasised:

- *fast tracking temporary changes to grid configuration to relieve transmission constraints* – some useful time was lost during the winter 2001 in discussion about tradeoffs between grid security and relieving constraints. Transmission providers naturally place a high priority on maintaining security. Unfortunately, this security comes at a price, and during a potential shortage situation that price can be high in terms of foregone generation. Ultimately the key parties came to a common view, but time was lost. To ensure that situation is not repeated it would be useful to have the plans prepared and agreed beforehand.
- *further developing interruptible contracts with large and medium-sized customers* – when spot prices rose steeply through June Contact diverted its account managers to the task of buying power back from customers. This was the first time Contact had carried out this activity, and progress was slowed by a lack of awareness by customers of the potential benefits to them. Effort was also expended on customers who had no interest in this mechanism. A faster response would have occurred had customers been identified beforehand.
- *having retail campaigns 'on the shelf'* - developing and deploying a retail conservation or incentive campaign requires a few weeks of pre-planning. To minimise delay in launching a campaign, it is useful to have a model ready to go before it is needed.

Reform transmission rentals system

Under current market arrangements large price differentials between different parts of the country can arise when the transmission system is constrained. When this occurs there is an excess of funds paid by wholesale purchasers over the amount that generators receive – this excess is referred to as transmission rentals.

Money derived from the differentials can mount up very quickly in a high price period associated with a dry year – more than \$80 million has been generated for 2001. Under present arrangements this money is collected by Transpower and rebated to lines companies and major users connected directly to the grid.

Transmission rentals should be reformed to allow customers to better manage price risks

From the lines companies' perspectives, this money is a windfall. Unlike retailers and major users, lines companies do not buy any electricity and therefore are not exposed when spot prices are high.

Some lines companies recognise the payment as a windfall, and rebate it to their customers. This helps to offset the high spot prices being paid by those customers. Others retain the differential payments. This makes no sense from a fairness or economic efficiency viewpoint. The money should be rebated to lines companies' customers to hedge some of their price risk.

What changes to the energy efficiency and conservation campaign should be considered in case the need arises in future for a similar campaign?

We think this question raises a number of separate issues that are considered below.

Should the government be involved with any future campaign?

It could be argued that with a wholesale market in operation, it was unnecessary for the government to become directly involved in running a campaign of its own.

While we generally support the notion of maintaining a separation of government and market functions, we believe the government should be prepared to play a role for the following reasons:

Government should be prepared to run its own campaign, but only when industry efforts are not sufficient

- there is a perception by many people that unless the government makes a pronouncement, it is not a serious issue. The government's active participation therefore has an important signalling function to wider society;
- the government sector is a large player in its own right – the stance taken by the government therefore has a direct effect on outcomes;
- the political reality is that in a hydro shortage, there will inevitably be calls for the government to act to do 'something'. It is far better to channel this effort into encouraging demand reduction than pursue other alternatives with low or negative returns.

In our view, the core decision for the government should revolve around what point does it become involved. It needs to be sufficiently early to be worthwhile, but also needs to recognise that the government should not be the 'first line of defence'.

Early preparation

Preparation allows a flying start

As noted in the previous section, we believe that it would be desirable to have energy efficiency and conservation campaigns prepared before they are needed. This would ensure that they can be implemented within a shorter lead time. This is true for both retailer/generators and EECA.

One industry wide campaign versus multiple campaigns

Early in the winter a number of retailer/generators discussed the possibility of jointly funding a campaign. This was seen as a means of ensuring maximum impact from the available resources. However, discussions foundered over differences of view about the best approach.

Industry players should choose between a unified approach and separate initiatives if they wish

While we believe that there would be some efficiencies from a co-ordinated approach, on balance we prefer the flexibility to allow different parties to choose the route best for them. As was seen in 2001, there was a diversity of approaches, and as a result a greater set of new ideas was generated for future use.

We note that Contact's campaign, which offered benefits to worthwhile, regionally identified community projects in return for achieving identified savings targets, captured strong buy-in from local communities.

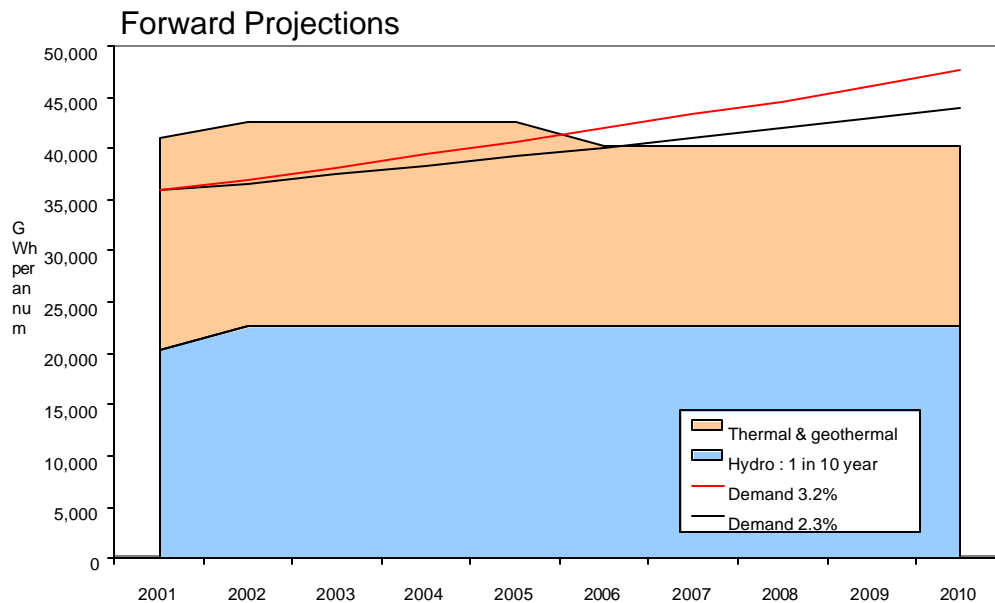
Future outlook

Although the terms of reference do not explicitly raise the question, we believe it is useful to briefly consider the implications of the recent winter for the future.

Supply and demand outlook

The chart below sets out a broad projection of annual supply and demand balance over the next decade using this year as the starting point. Hydro production is assumed at 1:10 year drought (i.e. lower than average but not especially severe – hence some of the recovery in 2002). Thermal production assumes high levels of output from baseload and mid-merit plant.

Demand is projected based on the historical growth rate of 3.2% for the last four years, and a lower rate reflecting increasing efficiency of use.



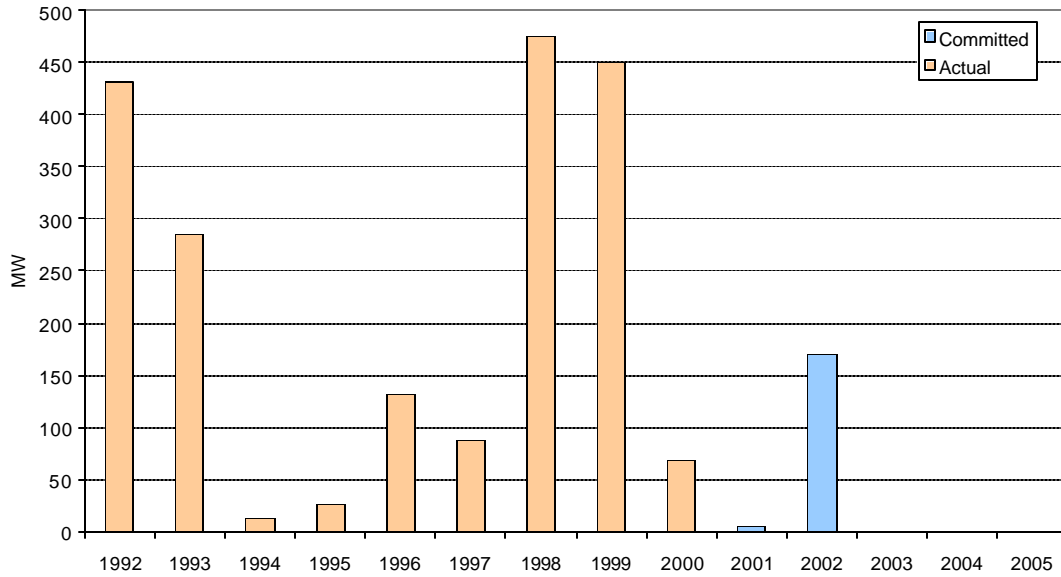
Source : Contact estimates

New generation needs to be on stream by 2004/05

The chart shows the present level of dry year margin will shrink over the next few years with growing demand, and from 2005, with retirement of old plant. In short, in the absence of very significant ongoing demand savings, there is a clear need for new generation to be available within 2-3 years. It would appear that the low level of prices experienced over the last four years, while benefiting those paying them, had a dulling effect on incentives to undertake new investment. This is evident when looking at the absence of any significant plant due to come on stream in the next few years.

New capacity coming on stream

No significant new investment has been committed for four years



Source : various. HVDC upgrade included as 50% of increased net MW transfer capacity

Even with a technology option that allows for a fast build program, it is unlikely that new plant could be commissioned until 2004/05. This increases the risk exposure from dry years over the next few winters.

What will new generation cost?

New generation can come from a variety of different sources – however they all have one feature in common – none of them appear to be economic at historical prices. As shown below, for new generation to be economic, it is likely that prices will need to rise to north of 5c/kWh.

New generation is not economic at historical prices

Type	Quantity	Cost	Comment
Wind	2-3,000 GWh	7-10+c/kWh	Currently high cost
Geothermal	3,000 GWh	5.5-7+c/kWh	Limited by suitable sites
Hydro	2-3,000 GWh	5.5-8+c/kWh	Limited by suitable sites
CCGT	??	5+c/kWh	Dependent on fuel

Hundreds of millions will need to be invested by 2004/05 in generation, transmission and/or gas fields

The cheapest option appears to be combined cycle gas turbine plant, although its timing and cost are dependent on securing fuel. In that context, it should be noted that investment decisions for new thermal plant will almost certainly be tied to the development of new sources of gas, as there are no existing uncommitted sources that provide the necessary length to underpin a new investment.

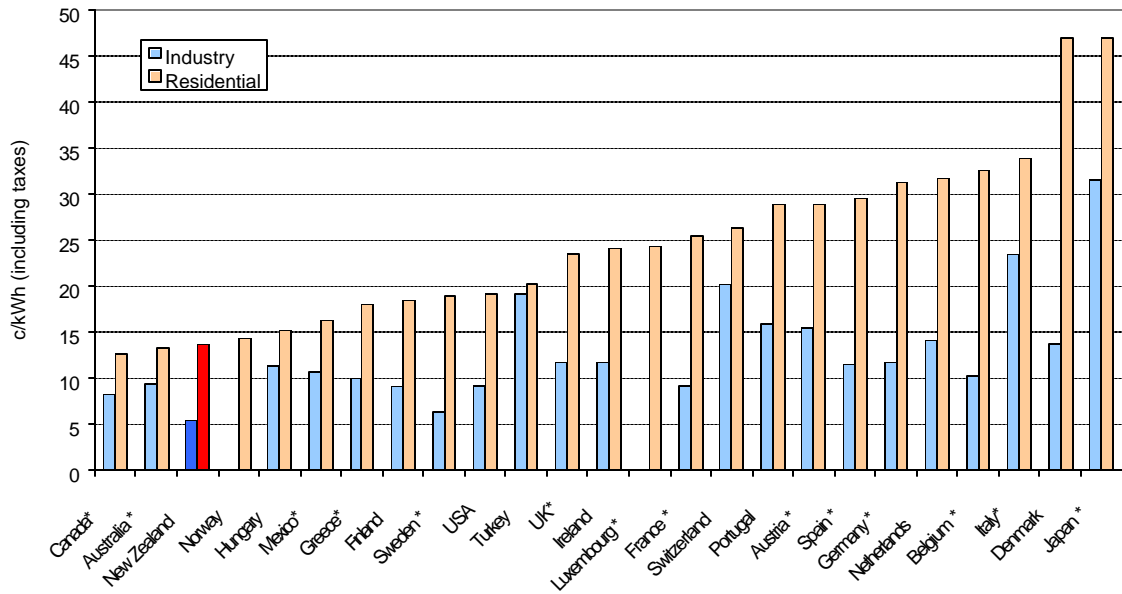
To avoid an energy crunch, commitments are required in the next 6-12 months

In conclusion, investment commitments in generation plant, electricity transmission and/or new gas infrastructure totalling hundreds of millions will need to be made over the next 6-12 months if New Zealand is to avoid a serious electricity crunch around 2004/05. To ensure those commitments are made in a timely fashion, it is necessary to reduce uncertainty in the regulatory environment in the energy sector.

It is also worth noting that even after allowing for some upward pressure on prices necessary to sustain new investment, New Zealand enjoys among the cheapest electricity in the world, and it should continue to be very competitive.

NZ enjoys some of the cheapest electricity in the world
 Even allowing for cost of new generation, power in NZ is likely to be very competitive

Price comparisons



Source : MED,
 * indicates most recent data is earlier than 4Q2000