NZEM
Marginal Losses vs Average Losses

Paper Presented By

Todd Energy Limited

15 August 2001

CONTENTS

Page

LIST OF FIGURES

Acknowledgements

I wish to acknowledge the very significant contribution made by the Todd Energy wholesale market group especially Babu Bahirathan and Charles Teichert in the analysis of the New Zealand Electricity Market. I would also like to thank Russell Markham for his review and comments on the economic analysis.

Rodney Deppe

1 EXECUTIVE SUMMARY

Most successful international commodity markets all tend to require delivery of the product to a specific designated value point. For example, one of the biggest commodity markets in the world, the WTI (West Texas Intermediate) Oil market requires delivery to a designated pipeline point.

The New Zealand Electricity Market (NZEM) is different in that it buys electricity from generators at one delivery point and sells electricity at another point, some distance away. Effectively what is being attempted is to combine or bundle an energy market with transmission of energy from one point to another.

The way in which the NZEM has bundled market supply and demand forces with the transmission of energy is to include non-market elements in its price determination. These non-market elements relate to losses. Losses in the NZEM model are determined not by market forces but by pre-determined formulas. This immediately compromises the "market" nature of the transactions as prices become strongly influenced by the formulas rather than the natural market demand and supply.

In addition to this instead of using actual losses, the NZEM has used marginal losses which are close to twice actual losses.

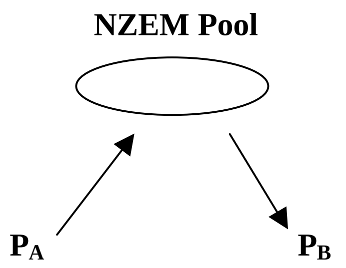
In summary this paper shows that by using marginal losses, as opposed to average losses, significant market distortion is created and it results in major mis-allocations of resources including the following:

1. In periods of drought, such as occurred in 2001, the wasting of water is encouraged. For example the South Island hydro is encouraged to generate more by being given higher marginal prices than would be the case if actual losses were used. Similarly, North Island thermals are given a lower price with marginal losses than with average losses and hence generate less.
   Then in periods of high rainfall, or flood, the South Island is given too low a marginal price (or even negative marginal prices) and as a consequence South Island generators dispatch less than is optimal and the result is that water is again wasted and more water is spilt than necessary.
2. The average market price is higher than the competitive price.
3. Consumers and retailers as a group pay significantly more as the delivered price is higher.
4. Competition between generators is reduced. Some generators are prevented from competing effectively and others are relatively protected from competition.
5. When the actual cost of line losses are used it becomes apparent that the NZEM model is currently dispatching more costly generation ahead of cheaper generation. Excessive amounts of more costly generation are being dispatched and not enough cheaper generation is being dispatched.
6. The total supply of generation that is available at each price level is reduced.
7. Marginal losses earn a monopoly rent.
8. If there was competition between two different electricity markets, one which used marginal losses and the other market used average losses, then the average losses market would have a lower average price, consumers in total would pay less, and generators in total would be paid more. Thus over time, if given freedom of choice, the majority of

consumers and generators would switch to a market that used average losses rather than marginal losses.

Because the NZEM decided to bundle energy transmission with the delivered energy market the losses have to be dealt with. The NZEM has to effectively buy more electricity than it sells. The difference being the actual electrical losses. The actual cost of the losses is the actual quantity of losses multiplied by the price the NZEM buys the electricity from the generators. The NZEM then has to recover the cost of these actual losses from consumers. If the losses to get the power from point A to point B are 5%, it will be necessary to recover this from purchasers by charging 5% more.

The NZEM instead of charging 5% more however charges purchasers close to 10% more for all purchases. The 5% in this case is the actual losses, and the 10% is what is called marginal losses. Marginal losses are the incremental losses that result from transmitting the last marginal unit of power.



Where P_A is the price at node A and
P_B is the price at node B

The NZEM is pricing each kWh to all users and generators as if each and every kWh was responsible for the last marginal loss unit when clearly it is only the last marginal unit that causes the marginal losses and hence only the last marginal unit (and not all the units) that should be priced at the margin.

The result of the NZEM pricing all units to generators and purchasers at the cost of marginal losses and not actual average losses is that the NZEM recovers a profit margin above the NZEM's actual costs to compensate for actual losses. This profit margin in respect of losses is 100% above the actual costs to compensate for actual losses. (The 100% profit margin is proved mathematically in appendix 1).

If the NZEM model used average losses, the 100% profit margin on the cost of losses would reduce to zero and the price paid by consumers would reduce and the price received by generators would increase. In effect half of the 100% margin from the marginal losses model comes from generators receiving a lower price, and the other half is paid by consumers who pay a higher price. The NZEM call this profit margin a Rent.

NZEM Marginal Losses and Monopoly Rents are Mis-allocating resources - Wasting Precious Water Reserves

Even when water is an acknowledged scarce commodity and there is an elevated risk of power rationing, the marginal price model is still making the generation regions such as

Taranaki and Huntly so price sensitive to additional generation that these generators frequently make more profit by generating less. Under marginal loss pricing each incremental unit of generation frequently results in such a sharp fall in the marginal price received that generators make more profit by cutting back on incremental generation. This occurs because the marginal price is applied not just to the incremental units of generation but is applied to all previous kWh of generation. Thus rather than pay the marginal penalty on all units of generation it pays a generator to cut back generation. By cutting back generation the marginal price on all units of generation can be increased. The marginal increase in price more than compensates for the marginally lower level of generation. Thus the generator increases profits by cutting back generation due to marginal loss pricing.

Thus even after the additional generation released by Transpower, after network constraints were reduced on 1 August, Taranaki thermal generation is still under utilised by around a further 150-200 MW at all times of the day. Huntly still has 300-400 MW spare capacity available overnight and about 100 MW in most afternoons.

The marginal pricing model is further, not allowing optimal use of the DC link. Even after the intervention by Transpower there is still 200 MW of spare capacity not used in the day. When the North Island thermal generation try to use the last 200 MW of spare capacity the marginal prices drop so quickly and to such a marked degree that the generators make more profits by cutting back on generation and not using the spare capacity. At the same time the marginal model is still maintaining a very high marginal price in the South Island. The South Island cannot easily switch off generation and import the power from the North Island because this will spiral up South Island marginal prices and force the South Island to pay the elevated marginal price. This elevated marginal price is paid not merely on the incremental marginal power imported but on all imports of power. Marginal pricing is thus forcing the South Island to continue to use water to generate rather than import power generated by thermal stations.

Decreasing Competition

New Zealand only has about 15% excess generation that is bid into the market in winter during peak periods. This is less than the 20-25% the World Energy Council[1] considers the minimum for competition. This is further aggravated by the 4 large generators all being individually larger than the 15% excess generation. This means they are individually all essential to satisfy demand and this gives them market power. At present the marginal pricing in the NZEM model is making this poor state of competition even worse because it prevents what low priced generation there is from getting into the market at an economic price. In other words the reason prices in the winter of 2001 were quite so high was simply because the marginal losses unduly price constrained any additional available generation and made this incremental generation uneconomic.

Marginal Losses is a Tariff or Tax on Trade – Causing Competition and Generation to Reduce

Using marginal losses instead of actual/average losses is equivalent to setting up a tariff barrier between the generators that is 100% higher than the actual costs attributed to losses.

[1] World Energy Council, “Electricity Market design and Creation in Asia Pacific”, May 2001, page 1.

The result of all tariff barriers is that less trade takes place. In addition less generation will be dispatched. The average market price will be higher and consumers as a group will pay more under marginal loss pricing.

Rentals

The rentals (caused by the 100% margin above actual losses) are considerable. Since October 1996 when the market first started the total rentals to July 2001 are $382 million. Last year the rentals were $92 million. This year the rentals for only the first 7 months of the year are $88.7 million. This is 135% more than the same period last year.

Although these numbers are large they significantly underestimate the real cost of using marginal losses. The real cost is that the 100% margin or tariff barrier is preventing generators from competing, artificially constraining generation, depressing the total revenue received by all generators and artificially escalating consumer demand side prices. Often the worst affected areas, with high losses, are the poorest and least developed regions such as the West Coast, Northland, Hawks Bay, and Gisborne. Even developed regions such as Auckland have relatively high losses and are paying a price at least 5-10% more than they should. Production and hence economic development is also affected in Taranaki, the South Island and other areas.

At present the rentals are paid by the NZEM to Transpower who then allocates this money to Line companies, who in turn are supposed to allocate this back to consumers. But, there is no check on this.

Because Transpower allocates the rental rebates on a similar basis to Transpower charges and then all the line companies (with only one exception) deduct the rental payments off line charges, the rental rebates effectively reduce network charges. This amounts to a cross subsidy of network charges by energy. This distorts generation location and transmission pricing relative to other energy sources.

Rebating rentals to consumers can never compensate consumers or generators for the lower levels of generation and higher average market prices caused by marginal loss pricing. Average loss pricing is expected to allow around 300 MW of additional generation to become economically available at peak times. Recent NZEM calculations in respect of price sensitivity compared to volume suggest that an additional 300 MW will lower the average market price by around 21%. At present (at $100/MWh) this would be worth around $630 million pa. At $50/MW this is worth around $315/MW.

The actual cost of marginal losses is thus not merely the monopoly rental collected but is also the cost of the higher market prices (i.e. $92 million + $315-630 million = $407-722 million) caused by marginal losses.

Monopoly Rental

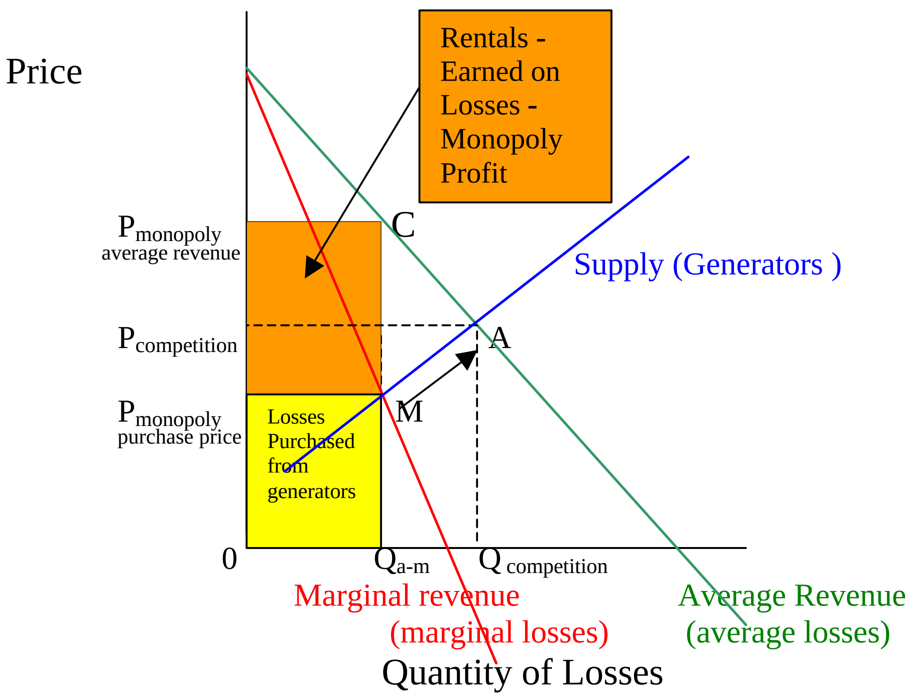
In a competitive market the competitive price is the price at which the marginal cost of generation equals the average market price (which is the average revenue of a single purchaser such as the NZEM). Under monopoly however the price at which a monopoly purchaser maximises profit is lower than the average market price. The profit maximising monopoly purchaser therefore offers to pay generators not the average market price but a much lower price. The monopoly can then keep the difference between the lower price and the average market price. The NZEM does exactly this.

The NZEM pays generators a price for each and every kWh as if each and every kWh had contributed to the last unit of marginal loss. This clearly misconstrues how the marginal loss is created. Similarly, the NZEM charges the demand side kWh as if each and every kWh had contributed to the last unit of marginal loss and hence recovers more than required to pay for actual losses.

The rental or monopoly margin is then the difference between the marginal price paid and the average revenue received for the losses and is a result of pricing losses at the level of marginal losses while only incurring around half this in actual losses.

By focusing only on the losses it is possible to graphically illustrate how the purchase of the losses at the lower marginal price, and recovering a margin above the actual losses, results in the rental. This rental is equivalent to a monopoly rent in microeconomics.

Figure 1 - Monopoly Rental made by NZEM using Marginal Loss Pricing



P_{monopoly} average revenue	is the average revenue the NZEM receives for the losses.
P_{monopoly} purchase price	is the NZEM purchase price of generation.
$P_{\text{competition}}$	is the average revenue the NZEM would receive for losses if there were competition. This is also the average revenue and equilibrium price received by generators and the equilibrium price the demand side will pay for losses if allowed to enter the losses market and compete.

The NZEM buys the electricity from the generators at $P_{\substack{\text{monopoly} \\ \text{purchase price}}}$ and sells the electricity at a higher price $P_{\substack{\text{monopoly} \\ \text{average revenue}}}$ and is thus able to make a monopoly rent or profit.

If competition was allowed in respect of purchasing losses, the generation price would be bid up to $P_{\text{competition}}$. At this price the generators will offer more generation. The increased generation however will only be demanded by customers at a lower price. Thus using actual losses the average market price will be lower. The loss rental is reduced to zero and no margin is made on losses and no monopoly profit is made.

Barriers to Reducing Losses

Losses in New Zealand are substantial 2500 GWh (8% of consumption) and are worth $250 million per year, at around current prices of $100/ MWh. It is therefore worth ensuring that not only the market deals with losses efficiently but also that other impediments are not placed in the way of reducing losses.

Distributed generation can significantly reduce losses as a percentage of consumption because distributed generation is situated at the site of the demand load. Yet, despite these obvious efficiency gains, and a recommendation from the Inquiry into the Electricity Industry (2000) and the OECD, both Transpower and the line companies continue to tightly control any distributed generation development. These network companies currently maintain a monopoly on transmission savings which prevents a distributed generator from gaining access to transmission savings without obtaining the agreement of the network companies.

While the Commerce Commission has previously expressed concern at these arrangements, it has not acted to remove transmission savings from being controlled by the network companies. The government to-date has also refrained from instructing its subsidiary, Transpower, to give equal access to transmission savings.

The monopoly network companies determination to retain their monopoly control of transmission savings has been reinvigorated by the recent passing of new legislation which allows them to build and own generation. They now can retain the transmission savings exclusively for themselves.

The result, is that location pricing signals for the siting of new generation continues to be significantly distorted, and industry is prevented from building economic distributed generation. This has increased the dependence upon the large hydro stations and significantly aggravated the 2001 electricity crisis.

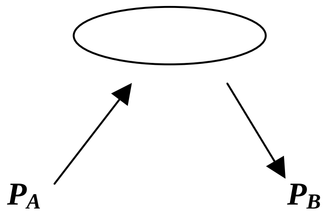
Industries which have been exposed to the current excessive high prices this winter could have reduced or eliminated their market dependence by building distributed generation.

2 INTRODUCTION

Transpower explained Loss Rentals as

Where power flows from A to B

Pool



Where P_A is the price at node A and
P_B is the price at node B

"the producer is paid P_A and the purchaser buys at P_B. The price $\boldsymbol{P_B}$ is 15% higher than the price $\boldsymbol{P_A}$. In effect, the pool has "transmitted" between A and B and made a gross "profit" of 15%. The net profit will be less than 15% because the pool has to cover actual losses (7.5%).
Transpower, Transmission Rentals, Information booklet. from The Transmission Services Group Transpower, from October 1996, page 7

The reason for the "Loss Rentals" is simply because the NZEM uses marginal losses rather than actual (average) losses and by doing this earns a 100% margin on the cost of the actual losses. Actual losses are average losses and are close to half marginal losses.

This means that the current NZEM model causes the price difference between a net generation region and a net demand region to be close to twice what it would be if losses were based on actual losses. This means that generators as a group receive less, and the demand side customers as a group pay more (than if the NZEM model used average losses).

In addition, there are numerous dynamic consequences. In summary it can be shown that using marginal losses as opposed to average causes significant market distortion and results in major mis-allocations of resources including the following:

1. In periods of drought, such as at present, the wasting of water is encouraged. For example the South Island hydro is encouraged to generate by being given higher prices (because of marginal rather than actual losses).

   Then in periods of high rainfall or flood the South Island is given too low a marginal price and as a consequence they are dispatched less than they should be and the result is that water is again wasted because more water is spilt than necessary.
2. The average market price is higher than the competitive price.
3. Consumers and retailers as a group pay significantly more as the delivered price is higher.
4. Reduces the competition between generators. Some generators are prevented from competing effectively and other are relatively protected from competition

5. When the actual cost of line losses are used it becomes apparent that the NZEM model is currently dispatching more costly generation ahead of cheaper generation. Excessive amounts of more costly generation are being dispatched and not enough cheaper generation is being dispatched.
6. The total supply of generation available at each price level is reduced.
7. Marginal losses earn a monopoly rent.
8. That if there was competition between two different electricity markets, one which used marginal losses and the other market used average losses, then the average losses market would have a lower average price, consumers would pay less, and generators would be paid more. Thus over time, if given freedom of choice, the majority of consumers and generators would switch to a market that used average losses rather than marginal losses.

Constraint rentals

When network constraints occur the NZEM model separates the constrained area for the purposes of determining price and the constrained area as a result receives a significantly lower price.

Constraint rentals will still exist in an average loss price model but the amount of dollars collected as constraint rentals are likely to be less because, firstly, the average market price at any one time will be lower than a marginal price model. Secondly, under an average price model the price difference between the node or GXP price and the average market price will be smaller because average losses are less than marginal.

3 THE NZEM MARKET

The NZEM market model although solved simultaneously can be thought of as two primary components. A demand-supply component and secondly, a losses component.

The two components are fundamentally different in that the losses are determined entirely internally, or endogenously, by a formula for the losses on the network, whereas the demand and supply are the actual demand and supply at all the GXP nodes.

Losses at a GXP are the difference between the price at each GXP and the average market price each half hour (weighted by volume) expressed as a percentage of the average market price in that time period. The average price expressed another way, is the average revenue at each GXP (price times volume at each GXP) divided by the total volume at all GXPs.

In New Zealand the general direction of the flow of power tends to be either north or south. The DC link separating the North and South Islands is the major constraint on the transfer of power between the North and South Islands. If the flow is north then the south is referred to as the net generation region. If the flow is south then the net generation region is in the north.

Net generation regions will thus have a price lower than the average market price and net demand regions will have a price higher than the average market price.

If there is a change from marginal to average losses, and it is assumed that demand and supply do not change, then net generation regions will receive a price increase and net demand regions will receive a lower price. This price change will, other things being equal, be half of the current price difference between the average market price and the current marginal NZEM GXP price.

While this on its own would seem to represent a significant efficiency gain in terms of the removal of a margin (which later will be shown to be equivalent to a monopoly rent), there are other far more significant dynamic efficiency gains that flow from using an average loss model.

Once the assumption is relaxed that demand and supply do not change as a result of the significant price differences between a marginal and an average price model, it becomes apparent that an average loss model will allow more demand side growth and generator growth. The lower average loss price to demand side industry may over time encourage greater industrial growth. While, generators will receive higher average loss prices and this will persuade generators to generate more. In addition, the price differential between different generators will decrease and hence there is more competition between generators. In most cases the price difference between generators will drop by close to half. Finally, by allowing more generation to be available to the market at any one time, the average market price will be even lower. This means that consumers effective get a double benefit firstly lower prices because average losses are lower than marginal and then the additional generation will also lower price somewhat. Generators in total however will nevertheless still receive a higher price as they will only generate more at a higher price.

A change to average losses will effectively split the current monopoly rental between generators and the demand side, with the demand side gaining a slightly greater share (to the extent generators increase generation).

Average losses were used for decades prior to 1996 and local line distribution companies still use average losses.

4 PRACTICAL EVERYDAY IMPACT

The wasteful consequences of marginal losses have become all too apparent in recent months.

4.1 Taranaki

In Taranaki in recent months the prices at Hawera (HWA 1101) have been close to zero or negative while prices at Haywards (HAY 2201) in Wellington are $500-800/MWh (Figure 2). A negative price means a generator has to pay to generate.

As a consequence Patea hydro dam (Hawera) was spilling water and Kiwi Cogen the largest cogeneration plant in the country has been reducing production. It is also clear from daily production data from the Transpower SCADA system that Contact's New Plymouth station seldom if ever ran at full production. While the recent reconfiguration of the grid has allowed some increase in generation the marginal losses have remained. Marginal loss prices add 100% to actual loss cost. This creates an artificial tariff barrier which causes too little generation to be dispatched in a net generation region and far too much generation to be dispatched in a net demand region.

A net generation region is defined as a region that receives a price below the average market price and a net demand region is a region that receives a price that is above the average market price (under marginal cost pricing).

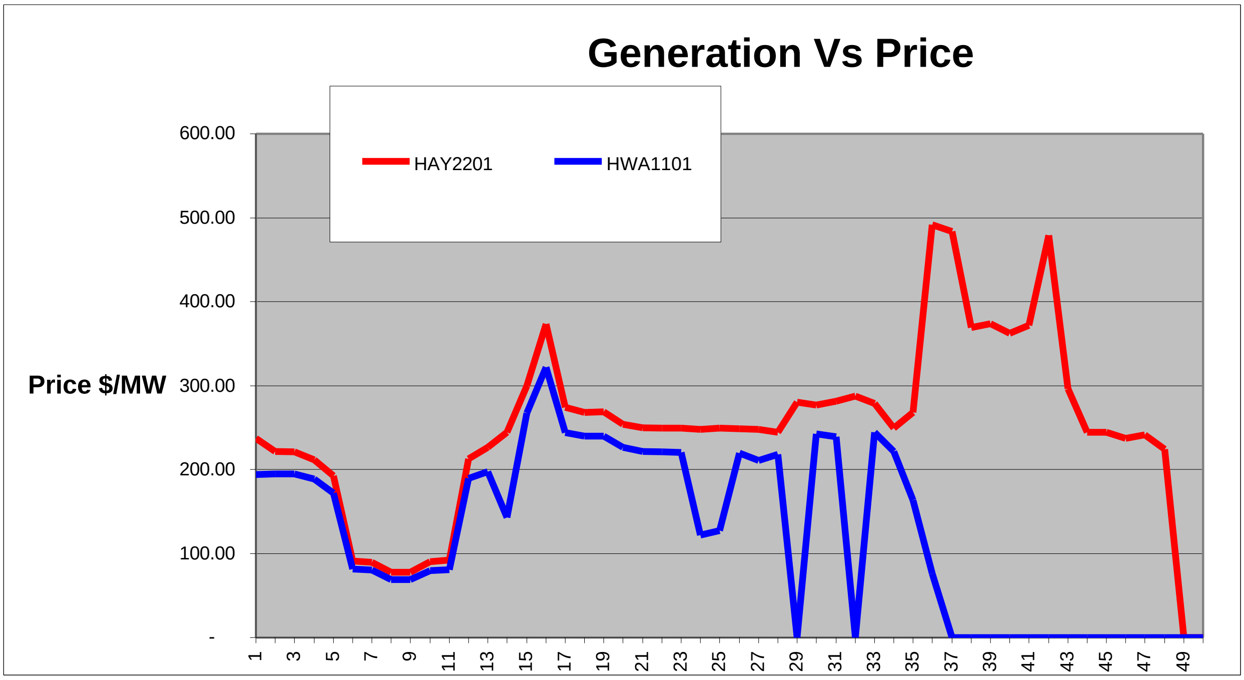


Figure 2 - NZEM Electricity - Price 30 July 2001

4.2 Marginal Losses Pricing is Wasting 100-300MW Hydro generation

During the present 2001 electricity crisis the flow of power has been generally south. When comparing the current marginal losses model to an average losses model, the NZEM model every half hour is dispatching incrementally too much South Island hydro and incrementally dispatching too little North Island generation. The North Island thermal generators emanate mainly from Taranaki, Huntly and Auckland. These areas will tend to have relatively high marginal loss factors during south flow of power as they are a significant distance from the South Island. The NZEM model every half-hour is thus dispatching incrementally too little North Island thermal generation and instead dispatching precious South Island water reserves instead.

SCADA information shows that Huntly, for example, is regularly cutting back thermal production at lower marginal prices, while at the same time, Meridian which is consistently being allocated high marginal prices, is producing and using water to generate when thermal generators could be generating to preserve the critically low lake levels.

The North Island generators are offered a price whose percentage difference from the average market price is twice as low as a model using actual losses, and South Island hydro generators are offered a price whose percentage difference from the average market price is twice as high as prices determined by actual losses.

Although this is occurring every half-hour of every day it is most obvious overnight. Transpower report that there have been no constraints on the DC link in recent months.

As an illustration of the impact during the current crisis, overleaf it can be seen that on 2 August Huntly prices plummeted from $200/MWh at 1am to around $80/MWh until 6h30 in the morning, and then stayed at around $200/MWh during the day. In response to the sharp drop in prices in the early morning Huntly decreased generation from 1000 MW to 600 MW. This is a 40% reduction. 400 MW of generation for six hours per day over a month represents around 6% of the present national hydro storage level.

In contrast in the South Island, prices hardly dropped at all overnight and were only $20/MWh lower over night than the daytime. Prices stayed at $220-250 during the whole night and day on 2 August 2001.

On the same day the price difference between Huntly (North Island) and Benmore (South Island) was around $40/MWh in the day but about $140/MWh at night. Without changing generation volumes the price differences between Huntly and Benmore, using average losses would have been about half, namely $20/MWh in the day and $70/MWh at night. Over night the Benmore price would therefore have been down approximately $35 to around $165/MWh and the Huntly price would have been up around $35/MWh to $110-120/MWh.

At these higher prices Huntly would have made an incremental margin of 100% on the cost (losses) of transmitting power to the South Island. Such a large increment in margin is a big incentive to generate at closer to full capacity all the time. A thermal plant generally has lower maintenance costs if it is run as close to full capacity as possible. This lowers the thermal stresses of expansion and contraction.

There is little doubt that Huntly and other thermal generators will respond to price incentives.

This has been a noticeable trend in recent months. Higher Huntly prices in the day have resulted in increased generation at Huntly in the day. Whereas Huntly was only running at around two thirds of capacity in early July, in the first half of August it was running at 1000 MW for long periods in the day in response to higher day prices.

In contrast Meridian is receiving the price signal of very little price difference between night and day. This is a price signal to continue generating about the same at night as the day. In other words do not cutback generation in the South Island overnight. In this instance, Meridian's hydro stations are being used as base load while Huntly is being used as the marginal plant. This is clearly opposite to what should occur.

North Island generators, of which Huntly is the biggest, are cutting back production in anticipation of the regular sharp price drop that occurs each night. If the 100% margin on actual losses were removed the North Island generators would not receive such a large price reduction at night. North Island thermal generation would not be cut back at night and total thermal generation over time would increase. Thus the thermal stations would act as base load stations.

The DC transfer capacity up until 2 August 2001 was only partially used. The reason was that the prices dictated by the NZEM model gave North Island generators prices that were too low, and the South Island generators were given prices that were too high.

If thermal generation increases overnight to an amount closer to the DC transfer capacity, then hydro will decline at night. The reason South Island hydro generation will decline at night is because higher DC transfer will decrease South Island prices overnight. If the prices are significantly lower at night than the day then with limited quantities of scarce water, the profit maximising position is to use the water for generation in the day at higher prices and at night to buy any generation required at the lower night prices. This will not only improve Meridian's financial position (given a fixed quantity of water) but will also preserve the South Island lake levels because generation will be required less at night.

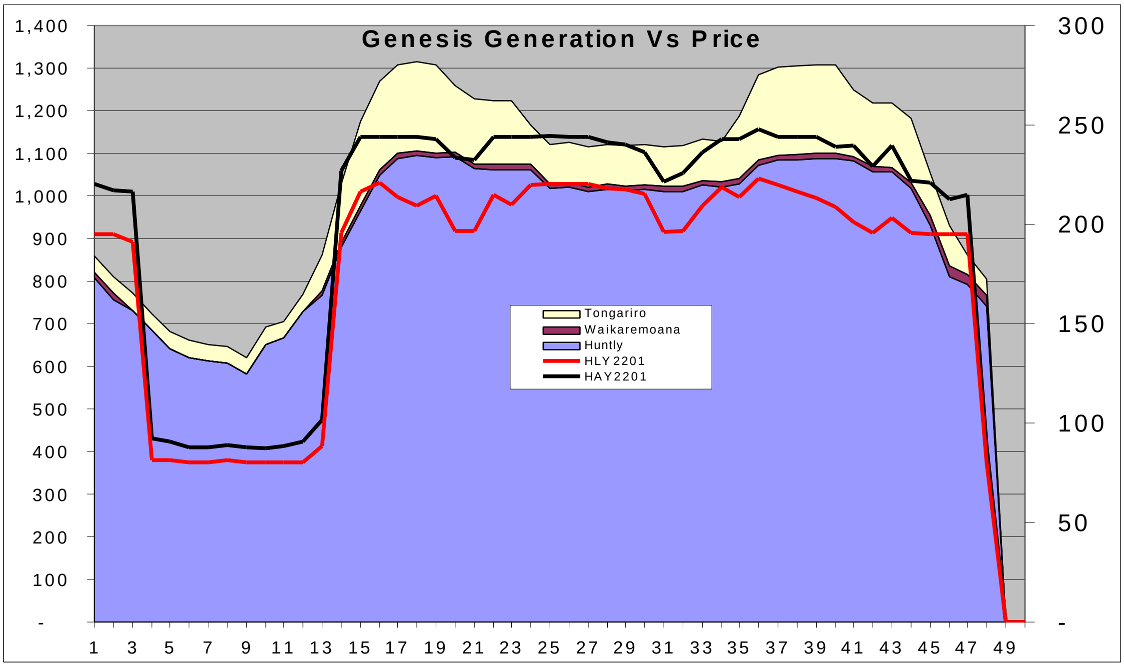


Figure 3 - North Island NZEM Price - 2 August 2001

One of the reasons DC transfer capacity is seldom if ever used to capacity is because under the marginal losses model the price drops very sharply. This is acting to discourage thermal generators from generating incremental generation because they get punished severely by such large marginal price drops across the DC that it is not worth-while.

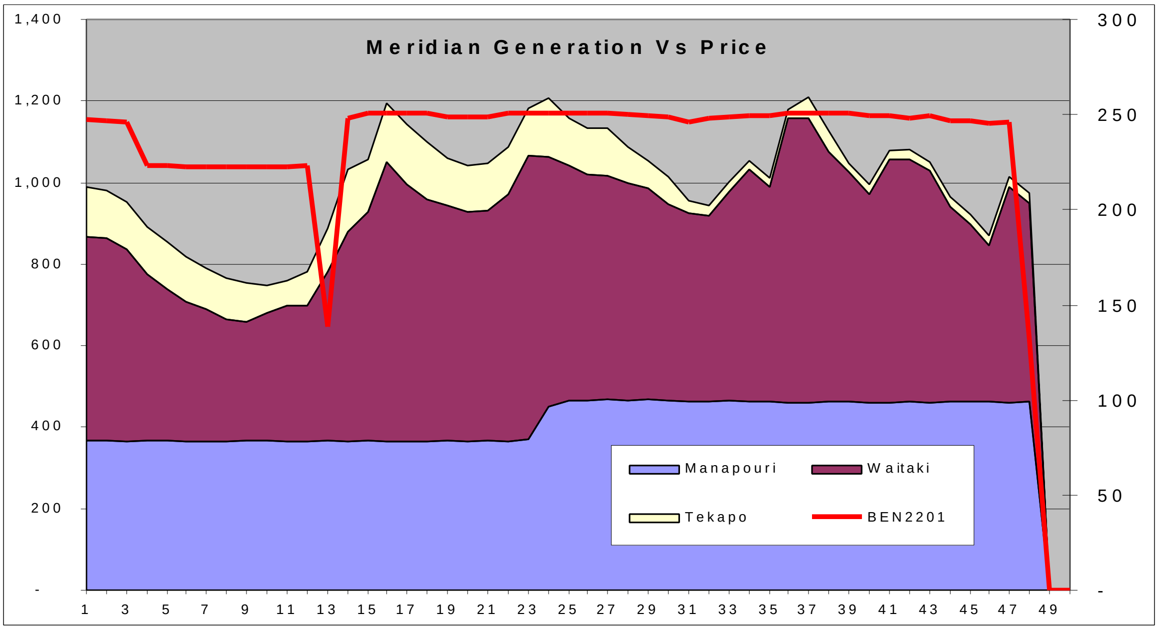


Figure 4 - South Island Generation 2 August 2001

The relatively small price variation between night and day in the South Island is a direct response and a predictable outcome from any form of tariff barrier. The 100% margin above actual costs is effectively a 100% tariff barrier on the cost of transmitting energy to the South Island. It is hardly surprising that sub-optimal transfer to the South Island is occurring with such large disincentives.

The removal of the effective 100% tariff barrier on the energy cost of transmitting power will impact on all generators. It would for example probably have avoided the recent spilling at Patea hydro dam, because prices under average losses would have remained positive for Patea at larger MW capacity and for longer periods.

Not only is Huntly cutting back thermal generation at night but so is Contact. Even after the recent grid reconfigurations Contact is still producing less than half its capacity at night because Taranaki prices regularly drop by $100-150/MWh overnight. Again this large drop is due to the marginal losses in the model.

It is estimated that between 200 - 400 MW additional generation will be economic to run not only overnight but at other times throughout the day if the NZEM model used average losses rather than marginal losses.

4.3 North Flow

Similarly during north flow all South Island generators currently receive a price which is too low (compared to an actual losses model), while generators in the north receive a price which is too high (compared to an actual loss model). In each case the price difference from the average market price is too low in net generation regions and too high in net demand regions by a factor of close to two.

Thus in north flow, generators in the south are getting the price signal to generate less than they should and generators in the north will tend to get the signal to generate more than actual loss costs suggest they should.

There are regions such as Taranaki, which are net generation regions during both north and south flow of power. The NZEM model will thus always be dispatching too little generation from these regions in comparison to any generator in a net demand region and they will also tend to be excessively displaced by any other generators even though they have lower bids in the market. This causes the demand side customers to pay significantly more under the current NZEM model rather than an actual losses model. This is because the NZEM model is effectively preventing the demand side buying power from cheaper sources of power by adding the 100% margin to the actual cost of conveying this power to the demand side.

An even more serious inefficiency is that by using marginal losses the NZEM price will approach zero at far lower generation volumes than an average losses model (see Section 5.2.2). This means that generation will be shutdown far sooner under marginal losses than average losses model. This comes about simply because mathematically marginal losses are twice average losses.

This is best illustrated by actual NZEM graphs (see Appendix 3 for demand-supply analysis). At peak times when the average price is say \$800/MWh and the unconstrained Taranaki price is zero the price difference due to marginal losses is then \$800/MWh. If the NZEM model used average rather than marginal losses the price difference between Taranaki and the average price (close to Wellington price) would be \$400/MWh. Taranaki generators are given an incentive to generate nothing at zero prices and probably at maximum levels at \$400/MWh. Therefore over a time period of say a month, Taranaki generation will increase if average losses were used in the model and not marginal.

In addition to this marginal losses creates a dynamic inefficiency. If generators in net generation regions such as Taranaki, were to generate then the greater volume of supply would reduce the NZEM model prices throughout the economy.

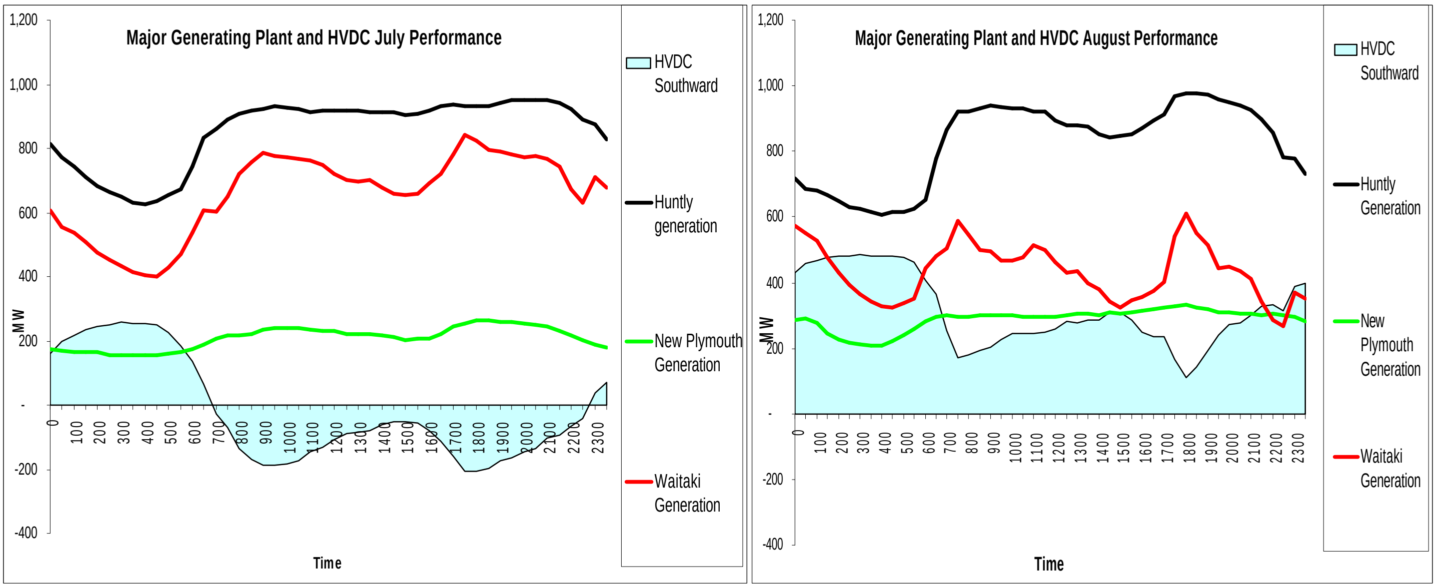
There is between 200-300 MW of production in Taranaki which is available to run but under the NZEM marginal pricing model it is often not economic to run. This is around 10% of off-peak demand and around 5% of peak demand.

The NZEM has estimated that a five percent decrease in demand would decrease the average daily price (time weighted) \$86/MWh or 21%. (See Appendix 4) and that a 10% reduction in demand would decrease price by 40%. This increases the excess generation above demand, which is offered into the market but is not dispatched. An increase in production capacity available to the market should have a similar effect.

4.4 Analysis of August Non-Market Intervention

The recent non-market intervention, since 1 August 2001, whereby Transpower was requested to temporarily reconfigure the Taranaki grid, has temporarily lowered the marginal losses (I don’t agree that they have changed the marginal losses, they have increased capacity and thus relaxed the constraints), and hence lifted prices sufficiently to allow some additional surplus Taranaki capacity to become economic. This reduction in marginal losses by intervention, will have a similar effect on prices to a change in the NZEM model from marginal to average losses. This therefore provides a unique opportunity to examine the effect on generation of a change in the prices due to losses.

A change from marginal to average losses will remove the 100% margin on the cost of losses and in so doing will achieve a similar price effect as lowering of marginal losses, but with the important difference that this will be country-wide, rather than isolated to one region, and the impact will be long term. This means that any benefits identified in this analysis can be multiplied many times over if spread throughout the country.



July August (first half)

Figure 5 - Generation and HVDC Flows in July and August

The graphs above (Figure 5) show actual average daily generation of Huntly (black), New Plymouth (green) and the Waitaki chain (red) as well as the actual transfer across the HVDC for July and August (blue shaded area). Negative HVDC transfer (blue shaded area below the line) reflects a North HVDC transfer. Each graph thus shows the average generation at each time period in a 24 hour period. For example, Huntly generation levels at 04h00 in the morning averaged across all the days in July showed that on average in July 600 MW was produced at 04h00.

The above graphs indicate the following:

Daytime generation:

The HVDC has 200 MW of spare capacity available in the day. There is still significant spare capacity in Taranaki (200 MW) that is not running because of the lower marginal NZEM prices.

- Huntly is generating close to maximum in the day in July and backing off a little in the afternoon in August again due to lower marginal NZEM prices.

- New Plymouth generation in July is constrained to 200MW and lifts to 300MW on 1 August due to the work performed by Transpower in relieving constraints (at a lower level of security) in the Taranaki region.
- Daytime HVDC transfer turns from a north transfer of 100MW on average in July to a South transfer of close to 200MW in the first two weeks of August. A 300MW turn around. Given that Huntly generation was at near maximum in July, additional generation must have come principally from extra generation in the Taranaki region which not only included New Plymouth, but Kiwi Patea and TCC as well.
- As a result of the increased south transfer, Waitaki has reduced generation substantially in August.

Night-time generation:

- HVDC transfer increases from 40% of maximum south transfer in July to close to 100% in August.
- Taranaki had 300 MW of capacity available overnight in July. In August New Plymouth generation has increased on average about 100MW, but there is still 150-200 MW of capacity available at all times of the day.
- Huntly has only increased generation slightly between July and August.

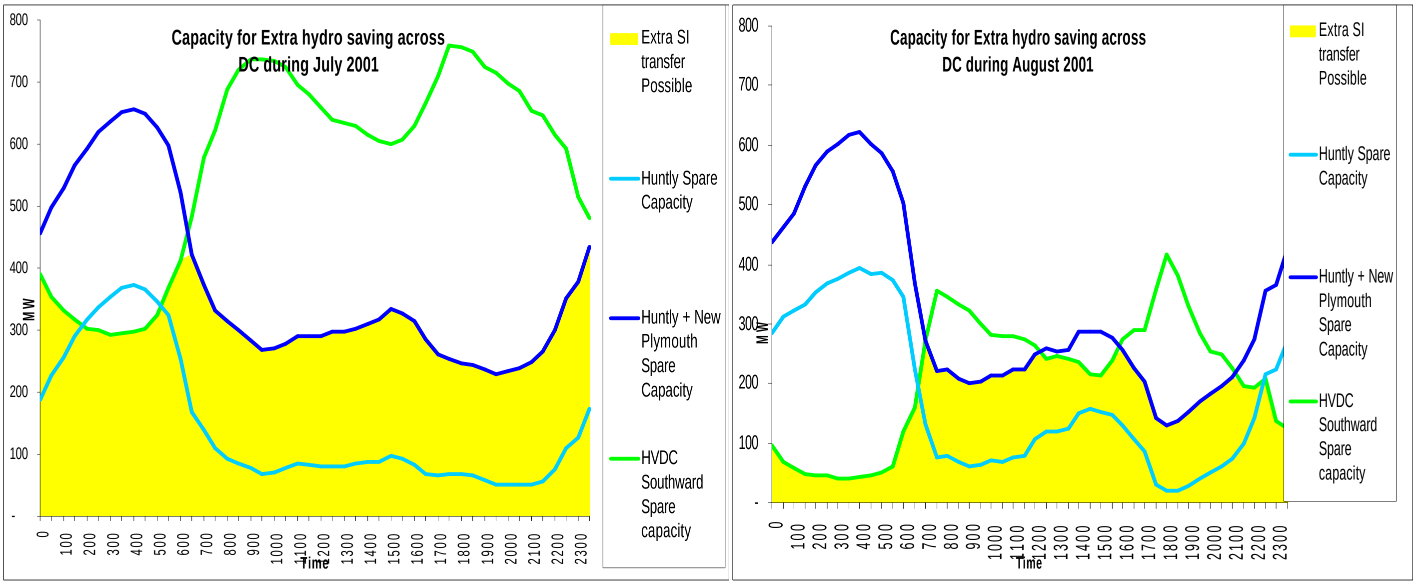


Figure 6- Taranaki and Huntly Generation and Spare HVDC Capacity

These graphs clearly show that during July and early August there was:

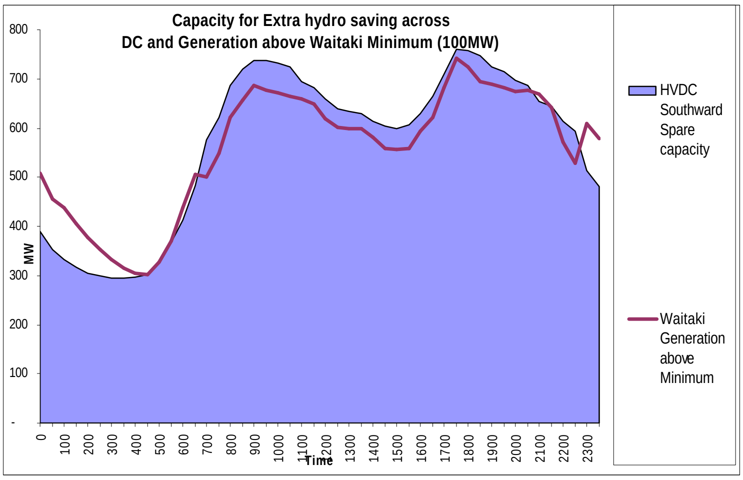
- unutilised surplus thermal generation capacity in the North Island and
- excess capacity available on the HVDC to transfer to the South Island.

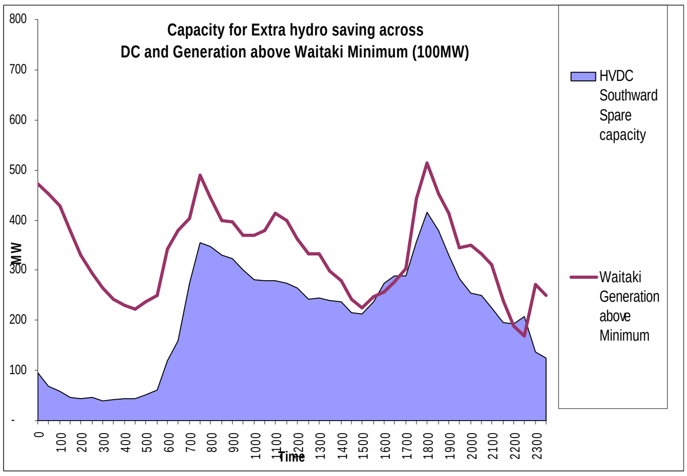
Huntly maximum generation is assumed to be 1000MW, New Plymouth maximum generation is assumed to be 440MW and the maximum HVDC South transfer is assumed to be 525MW.

A result of the increase in thermal generation from the North Island since 1 August, due to the reconfiguration of the Taranaki export circuits, is that the South Island hydro have made some savings in August. In the first two weeks of August, since intervention, the South Island has been generating closer to minimum levels overnight, but is still generating 300-

400 MW more than minimum during the day. There is thus considerable room for further savings.

It is apparent that in both July and August there is still extra thermal capacity available to be used to reduce SI hydro generation and that there is also capacity to transmit the power across the HVDC. In July this situation existed during the day as well as at night. In early August, after the intervention, the night position is very close to optimal but in the day there is still 200 MW of spare capacity to transfer south cross the HVDC. The difference between July and August being the temporary relaxation of transmission constraints in the North Island allowing some additional available capacity from New Plymouth to be dispatched instead of more valuable hydro resource. (I think we need to get acres the message that this is not purely a bidding issue)

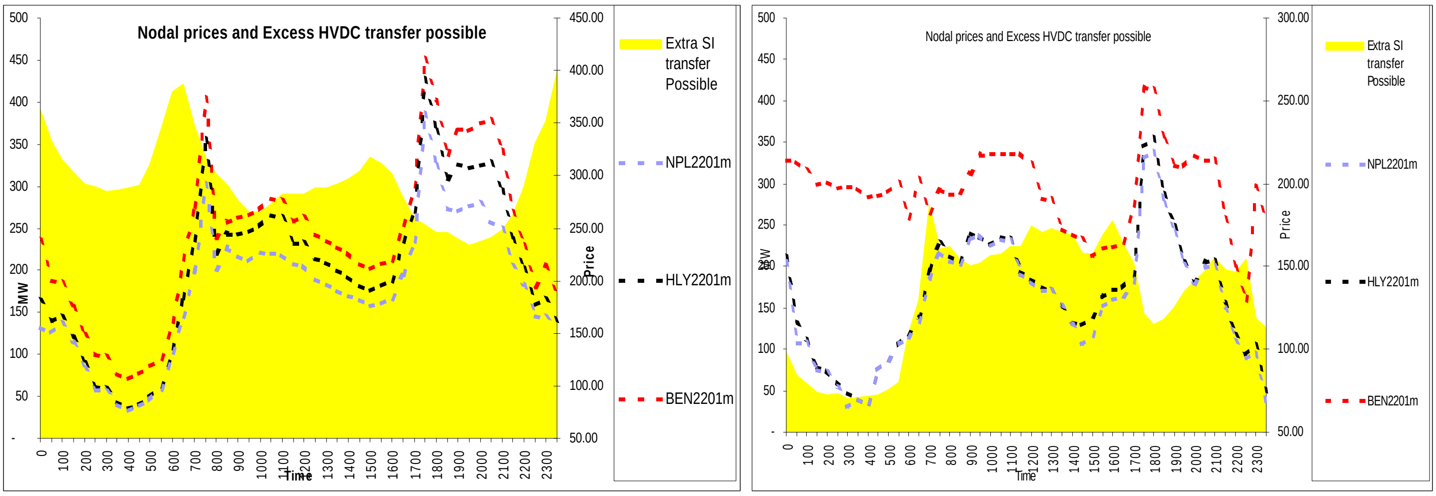




July | August (first half)

Figure 7 - Waitaki Generation and Spare HVDC Capacity

The above graphs indicate that there is significant capacity for the Waitaki chain to reduce generation to a point above minimum generation. Minimum generation is assumed to be 100MW to allow for minimum outflow constraints. The Waitaki generation above 100MW is the red line and is still 200-500 MW even after the intervention. The reserve requirements to support a maximum HVDC south flow is the blue area. The graph shows that during the day, after the intervention on 1 August, there is still 200-400 MW of HVDC capacity that remains unutilised. . Waitaki generation in the day, above its resource consents minimum still exceeds this by 200-450 MW. As there were no constraints in getting extra generation to the DC or through the DC, there appears to be no physical constraint to satisfying the South Island demand for power from the North Island in the day. Taranaki and Huntly (mid afternoon) have surplus power that could be exported to the South Island. The only reason that this does not occur is because the marginal prices they receive are too low. Hence instead of importing the power from the North Island in the day, the South Island increases generation and effectively wastes its scarce water when it could be preserving it.



July August (first half)

Figure 8 - Nodal Prices and Excess HVDC Capacity

The above graph (Figure 8) show price movements between July and August and the excess capacity to transfer south.

Note that the introduction of the changes to the transmission system has not only allowed extra generation from the Taranaki region to be exported, but North Island prices have dropped significantly. This has contributed to increased competition among generators.

The marginal price differentials North Island vs South Island have also increased significantly – from only $20-40/MWh last month both night and day, when there was on average 300 MW of spare capacity on the HVDC link in July, to a sharply higher price differential of $150/MWh overnight in August, when there was on average still 50 MW of spare capacity on the HVDC link overnight and Huntly and Taranaki overnight prices were pushed to close to the cost of production at $60/MWh.

Average loss pricing will approximately halve the difference in price between North and South, from $150/MWh to $75/MWh overnight, and from $60-70 to $30-35/MWh in the day. Thus prices will drop in the South Island which will pay less to import electricity from the North Island and give the North Island generators more incentive to generate additional MW. Every extra MW that the thermal generators produce will increase total supply, and with demand the same, average prices will be lower over the whole country. This is an example of the dead weight loss or loss in system efficiency. This has the effect of lowering the standard of living for all New Zealanders by increasing the cost of delivered power and by lowering real term wages because business activity is lower.

In August after intervention, the marginal losses 100% tariff barrier can be seen to be protecting the South Island from competition by firstly placing aggressive downward pressure on North Island prices when there is still 200 MW of daytime spare thermal capacity and spare DC capacity, while at the same time maintaining South Island prices. The DC link in the day still has close to 50% spare capacity yet the large $60-70/MWh price difference between North and South suggests little or no spare capacity. A significant price discrepancy in North-South prices should only be possible if there is no spare capacity left on the DC link, however this is not the case. This shows very clearly that marginal pricing provides a strong incentive to under utilise network assets that could result in wasteful over investment in assets. Both these factors will tend to cause Transpower grid unit charges to be higher than they would be under an average loss pricing system.

This is a clear illustration of the impact of the marginal loss model which in net generation regions aggressively drops price at close to twice the rate of actual loss costs, but in net demand regions increases price at close to twice the rate that actual loss costs increase.

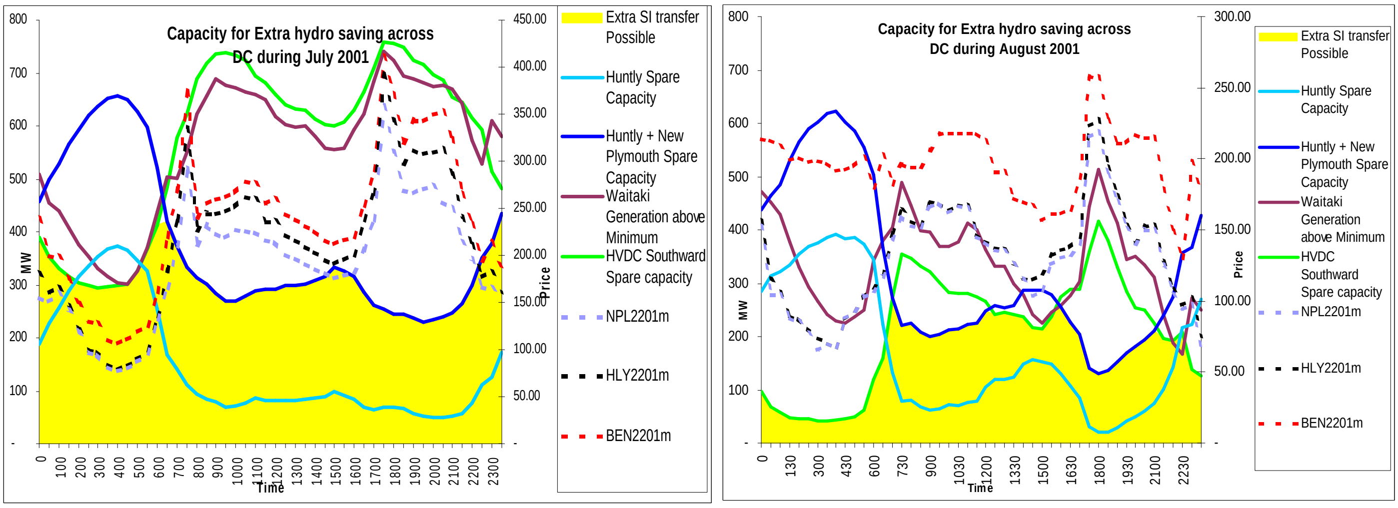
If there is excess thermal capacity at Huntly and New Plymouth and there is excess capacity to transfer the thermal generation to the South Island this should allow the Waitaki chain to conserve hydro resources. Why do South Island prices remain so high?

Answers may be a combination of the following:

a) The NZEM marginal-pricing model to dispatch plant according to price discourages efficient use of existing transmission capacity since marginal losses are close to twice that of actual average losses.
b) The enhancement of market power due to the marginal pricing model isolating generation pockets and preventing them from making additional generation available to the market.
c) Transmission system in the North Island is not optimised; for example constraints limiting export from the Taranaki region.
d) Market power of large generators at peak times when the excess bids into the market falls below the size of the largest generator's bid.

To date the industry has been trying to address point c) only. Significant effort has been applied in this area and good results have come from that work.

However, some of these measures are not long term given the grid security implications. In the long term points a) and b) and d) will have to be addressed to ensure the correct market forces result in the appropriate responses from competitive participants not only in times of shortages but all the time.



July August (first half)

Figure 9 - Capacity for Additional Hydro Savings

4.4.1 Summary of Conclusions

The overall conclusion is that the non-market intervention of Transpower to overcome network constraints in Taranaki has allowed between 100-200 MW of additional Taranaki generation to temporarily receive a higher price that is sufficient to generate economically. The increased competition from extra Taranaki generation has contributed to a marked reduction in the average market price, which in the first half of August has fallen by about $200/MWh.

Although this is a temporary network reconfiguration it is a good example of the kind of increase in generation that will result from moving to average as opposed to marginal losses.

The good news is that there is still around a further 150-200 MW of Taranaki thermal generation at all times of the day that is still <u>not</u> being dispatched. The marginal price model makes the Taranaki and Huntly price so sensitive to additional generation that it is not worth them generating more, as each incremental unit of generation results in such a sharp fall in the marginal price received for all the previous kWh units of generation that the generators actually make more profits by cutting back on generation. Another way to look at this is in a net generating region, the profit is maximised per kWh by reducing production while in the net demand region profit is maximised by increasing generation. This is a direct result of the NZEM charging a monopoly rent by using marginal loss pricing. Micro-economics predicts exactly this result (see appendix 3). Without changing the marginal nature of the NZEM model extra thermal generation cannot be obtained. To enable this generation to be available to the market the NZEM will have to switch from marginal to average losses.

An even more important conclusion however is that when this difficult period is over, and the Taranaki system is reconfigured back to its previous lower level of constraint, a change from marginal to average is likely to permanently make 250-400 MW extra generation available to the market from Taranaki alone. Additional generation will also become economic for all other generators.

This addition generation is available from both Taranaki and Huntly still has 300-400 MW spare capacity available overnight and about 100 MW in the afternoon.

The marginal pricing model is also clearly <u>not</u> allowing optimal use of the DC link. In July, during the day, the DC link had 250-300 MW of spare capacity and in August after intervention (at temporary lower security levels) this dropped to 200 MW. Why is this spare capacity not being used even in a crisis? The reason is that when the North Island thermal generation tries to use this spare capacity the marginal prices drop so quickly and to such a marked degree that it does not pay to use the spare capacity. This is the cost of the marginal rather than average NZEM model. This is made very clear in the first half of August data. Whereas in July the price difference between Huntly and Benmore (South Island) was on average only $20/MWh during the day, in August with spare HVDC capacity reduced to 50 MW the difference in price ballooned out to $50/MWh in the day and $150/MWh at night. It is further worth noting that despite the increased transfer of generation to the South Island in August, the marginal model still maintained a high South Island price above $150/MWh on average in the day. The marginal pricing NZEM model is thus sending a signal to the South Island to use its precious water reserves ahead of using the spare daytime capacity on the DC to import additional thermal generation.

The NZEM marginal loss model, by adding the 100 % margin to the cost of transmitting generation (losses cost), is very clearly sending pricing signals which are misallocating resources. The cost of this is now clearly evident, and even in a normal year will easily run into hundreds of millions of dollars.

Since the beginning of August average market prices have dropped by around $100/MWh. This is a very significant drop. A significant contributor to this drop in price has been the additional generation made available from Taranaki. This strongly suggests that if the effective 100% tariff barrier between generators was removed and if this was done throughout the country then this should significantly lower prices to demand side consumers and simultaneously also allow generators as a group to generate more and receive a higher overall price.

In winter New Zealand only has about 15% excess generation that is bid into the market at peak times. This is less than the 20-25% the World Energy Council considers the minimum for competition. This is further aggravated by the 4 large generators all being individually larger than the 15% excess generation. This gives them market power. At present the marginal pricing NZEM model is making this poor state of competition even worse because it prevents lower priced generation from getting to market at an economic price. In other words the reason prices in the current crisis are quite so high is simply because the marginal losses unduly constrain any additional available generation by dropping the price of this generation at a rate which is twice as aggressive as actual loss costs.

4.5 Rentals

The rentals (caused by the 100% margin above actual losses) are considerable. Since October 1996 when the market first started the total rentals to July 2001 are $382 million. Last year the rentals were $92 million. This year the rentals for only the first 7 months of the year are $88.7 million. This is 135% more than the same period last year. There is a clear trend appearing for rentals to grow.

In any one month rentals can vary from 2-20% of the total revenue paid out to generators or paid by the demand side. Some areas are very severely affected and can get as high as 50%.

Although these numbers are large they significantly underestimate the real cost of using marginal losses. The real cost is that the tariff barrier has prevented generators from competing, artificially constrained generation, and artificially elevated consumer demand side prices. Often the worst affected areas with high losses are the poorest and least developed regions such as the West Coast, Northland, Hawks Bay, and Gisborne. Even developed regions such as Auckland have relatively high losses and during north flow are paying a price at least 5-10% more than they should. Production and hence economic development is also affected in Taranaki and South Island generation.

At present the rentals are paid by the NZEM to Transpower who then allocates this money. Transpower state

All customers are allocated a share of the 'Rentals Received" corresponding to the connection and grid charges that they pay. Transpower, Transmission Rentals April 2000, Page 8.

This effectively means that the Line companies get the lions share of the rentals. The Line companies are supposed to allocate this back to consumers but there is no check on this. With one exception (Vector), all other line companies who have been asked, say that they do not actually repay this directly but do so via a reduction in line charges.

Because Transpower allocates the distribution of rentals on the basis of connection and grid charges, the rentals act as a rebate off these charges. By effectively reducing Transpower's the connection and grid charges the rentals act as a cross subsidise of Transpower charges.

There is no compensation for the lower level of generation and higher average market prices caused by marginal losses[2].

The NZEM recently advised the Minister that only a small reduction in demand of 5% would increase the surplus generation offered into the market sufficiently to cause a decrease in price of around 21%. (see appendix) An increase in surplus generation can have a similar effect. A 5% increase in generation at peak times is 300 MW. In off peak 300 MW is 10% of the capacity. An extra 300 MW is a conservative estimate of the amount of incremental generation that is likely to become economic by switching to average losses rather than marginal losses. Total demand side payments per year at current prices of around $100/MWh is around $3,000 million. Additional generation by switching to average losses will thus decrease the cost to consumers by $630 million.

21% of $3,000 million (@ $100/MW) = $630 million
21% of $1,500 million (@ $50/MW) = $315 million

Whether the NZEM was correct in its estimates of price sensitivity to volumes or not does not change the fact that a change to marginal losses will significantly lower prices for consumers and that these efficiency savings will result in large saving for consumers.

The actual cost of marginal losses is thus not just the monopoly rental collected but is also the cost of the higher consumer demand side prices (i.e. $92 million + $315-630 million = $407-722 million).

The beneficiaries are the network companies (Transpower and the Line companies) who even if they do pay the money back, do so on the basis of a reduction or rebate off their charges. Electricity Network costs are thus reduced and energy costs are increased.

Electricity lines compete with gas lines for the transmission of incremental energy. For example an electricity generator can be situated at a gas field and use the electricity network to convey the electricity to demand centres, or the gas can be taken to the cities where it is used to generate electricity and used in efficient cogeneration plant. If the gas is taken to the demand centres the electricity networks will be bypassed. The network companies therefore have an incentive to try and avoid this. The NZEM rental subsidy of Transpower and Line Company line charges will go some way towards assisting the network companies to avoid this competition at the margin.

[2] South Island generators also receive the portion allocated to the HVDC link in proportion to their Anytime Maximum Injection. This means that when the power is flowing south as at present the South Island generators not only get the benefit of the higher marginal prices but also receive the loss rentals created by excessively large marginal price differential across the HVDC link. This means that South island generators have an incentive to retain the high marginal price differential across the HVDC link during periods of south flow.

The rental and the distribution of rentals can thus be seen to distort resource allocation not only within the market but in other markets through-out the economy. This significantly lowers the productivity of the entire economy and in this way serves to depress the standard of living of all New Zealanders.

4.5.1 Transpower Lobbying to Retain the Rental

Transpower personnel have argued to keep the rental.

This misses the point entirely. The key distortion is the charging of the rental in the first instance. Who-ever charges the rentals is still causing the lower marginal generation and higher average market price.

Whether Transpower, the line companies, the NZEM or anyone else retains the rentals, the distortions in the electricity market still remain.

If Transpower did retain the monopoly rents then investing to remove grid constraints would reduce the monopoly rent and would reduce Transpower's return on investment, and hence investing in the grid would become irrational from Transpower's perspective.

If Transpower keeps the rental then Transpower will have an incentive to ensure rentals are maintained at optimally high levels by restricting investment in the grid. This will maximise return on investment for Transpower. Transpower can thus never be allowed to retain the rentals, because a rational Transpower would have an incentive to make the existing constraints worse not better.

Transpower has also suggested that rather than fixing the underlying cause of the distortion, marginal losses should be retained and that it should rather tender hedges which will lock in a specific marginal loss factor. Hedging or locking in a specific marginal loss factor will simply lock in the size of the monopoly loss rents. It will not avoid the rents. It will effectively lock-in the distortions in the electricity market and related markets.

5 PERSPECTIVES ON MARGINAL LOSSES

The marginal losses vs average losses can be looked at from a number of different perspectives. By looking at losses from different perspectives different aspects of marginal losses can be analysed. In addition it can be shown that all the different perspectives converge on the same result.

1. Marginal Losses is a Tariff or Tax on Trade – Causing Competition and Generation to Reduce

2. Micro Economic Theory

5.1 Marginal Losses is a Tariff or Tax on Trade – Causing Competition and Generation to Reduce

Each generator at a GXP effectively competes with every other generator at each of the GXP nodes around the country. The difference in price separating generators from competing with each other on price is due to losses between GXPs. Using marginal losses instead of actual/average losses is equivalent to setting up a tariff barrier between the generators that is 100% higher than the actual costs attributed to losses. The result of all tariff barriers is that less trade takes place.

What is happening in the NZEM in respect of losses is directly analogous to imposing a 100% tariff on the cost of transporting goods to export markets. What will happen is that countries like New Zealand, that are situated far away from markets, will simply decrease their trade with other countries and will be replaced in the market by countries which are closer to the market. New Zealand will even be replaced in the market by countries which have higher actual production cost, simply because the other country is closer, and the transport component multiplied by the 100% tariff is less.

Even if the importing foreign countries were paid back all of the 100% tariff charged the foreign countries are still not going to import any more goods from New Zealand and thus New Zealand will lose trade share to countries closer to markets. This is simply a trade barrier protecting countries with low cost transport. This is important because in the context of the electricity market, it has been argued that paying the loss rental back to lines companies which are then supposed to rebate this off line charges rectifies the problem. Resource misallocation once distorted cannot be rectified in this manner. For example, once the South Island water has been used ahead of North Island thermal the water is gone it cannot be restored and when the country experiences rationing or blackouts the loss rentals will not restore the misallocation of resources.

In the same way using marginal losses rather than actual losses means that generators which have lower losses are artificially protected from competing with lower cost generators which have a lower all up <u>actual</u> delivered cost (using actual losses). The tariff on the cost of transport, in this case losses, is thus used as a trade barrier to protect against competition.

This protection from competition will tend to enhance any market power. This occurs because firstly, the volume of excess generation is reduced because many generators are given such a low marginal price that it is uneconomic to produce at the lower marginal prices. Secondly, areas that do have incremental excess generation are forced to accept a significantly lower marginal price not merely on the incremental excess generation but on all the previous units of generation. The rational response in this situation is to not dispatch the incremental generation.

In the short term the result for the whole market is that generators which have higher marginal losses, generate less than they should (or at least have less of an incentive to generate). In comparison generators with low marginal losses are protected to the extent of the 100% tariff on actual losses and will generate more than they should (or at least will have an incentive to generate more than they should).

In respect of consumers, consumers will always pay more for electricity under a marginal loss system than an average system, and this will be for two main reasons.

Firstly, if generators require a certain price to run the generation economically, the delivered cost to the consumer of this generation is always going to be this price plus the losses. As marginal losses are always twice average losses, if consumer have to pay the marginal price, then consumer must always pay more for losses than the actual cost of the losses.

Secondly because there is less competition between generators simply because some are relatively protected from competition, the supply of generation will be lower and the price must therefore be higher.

Long term the distortions in the market will multiply and ripple through the economy. Areas with high marginal losses such as remote areas e.g. Northland will be unattractive sites for major industries to establish factories, as their plant will only make the already marginal losses worse. Generation has no incentive to situate in these high marginal loss areas because the very siting of major generation in the region removes the high prices due to high marginal losses.

Transpower's idea of long term contracts in respect of marginal losses will also not resolve the misallocation problem but will simply lock the resource misallocation in for the term of the contract and prevent changing to a more efficient market structure for the term of the contract.

It is important to note that even if loss rentals were also paid back to generators via network rebates, this would not rectify the distortion. The key distortion is that marginal prices cause reduced generation, reduced competition between generators, and erects barriers protecting some generators from competition. Volumes of generation cannot be changed after the event and hence no amount of rebate can rectify the distortions after the event.

If the loss rentals are paid back to consumers, the consumer is still in a net loss position because the repayment of loss rentals can never retrospectively change the volumes of actual generation generated by each generator under the distorted marginal loss price signals. Thus consumers cannot be compensated for, firstly, being forced to buy a greater share of generation from the protected generator at a higher net actual price. Secondly because marginal losses lower the total revenue received by all generators as a group (i.e. generators as a group receive a lower average price), this causes less generation to be economic at any given price level. Lower supply volume means that the net price paid by consumers even after repayment of loss rentals will necessarily be higher.

5.2 Micro-Economic Theory

The loss rentals can be shown to be a pure monopoly profit and as such result in what economists call a dead-weight loss which is a lose-lose outcome for the market including retailers, consumers and generators.

The loss rentals are the difference between marginal losses and actual (average) losses at each GXP multiplied by the quantity at each GXP. (See Appendix 1 and 2 Transpower Explanation of Loss rentals)

5.2.1 The Economics of Competition vs Monopoly

The demand curve comprises the aggregate of consumer demand. The market price is therefore the average revenue or revenue per unit of product that the market is prepared to pay for the total units of product made available to the market.

A perfectly competitive firm is a price taker and will hence not be able to influence market price. Consequently the firm in a competitive market will produce more production until its marginal cost equals the market price (average revenue).

A monopolist on the other hand will continue to reduce availability of a product as long as the consequent increase in price increases total profits. The profit maximising price for a monopoly seller is always higher than the market price under competition because the monopolist will continue to increase profits by withholding product. Similarly the profit maximising price for a monopoly buyer (monopsony) is always lower than the market price under competition. This is because the monopolist will continue to increase profits by purchasing less product from the market. (See diagram below).

5.2.2 The market for Losses

Losses are the energy that is discipitated as heat when conveying electricity from A to B. Because of losses the market has to purchase more electricity than it sells on the demand side. The cost of losses is then recovered from both consumers and generators on the basis of the degree to which they contributed to the cost of the losses. Generators in a generation region are thus given a lower price and consumers in a demand region pay a higher price.

In order to send power from A to B losses will be incurred and hence the generator at A has to generate more electricity than is taken out at B. Electricity markets typically recover the additional cost of losses by either adding the average loss (actual losses) to the quantity or the price of the electricity. The NZEM does the latter, adds the losses to the price but instead of adding actual costs adds actual costs plus a 100 % margin on the basis that this is the marginal loss.

Transpower in their publication Transmission Rentals explains the concept of Loss Rentals as follows: (*Transpower, Transmission Rentals, Information booklet from The Transmission Services Group Transpower, page 4)*

Where power flows from A to B

$$\mathbf{P_A\ Q_A} \longrightarrow \mathbf{P_B\ Q_B}$$

Where P_A and Q_A are the price and quantity respectively at node A and
P_B and Q_B are the price and quantity respectively at node B

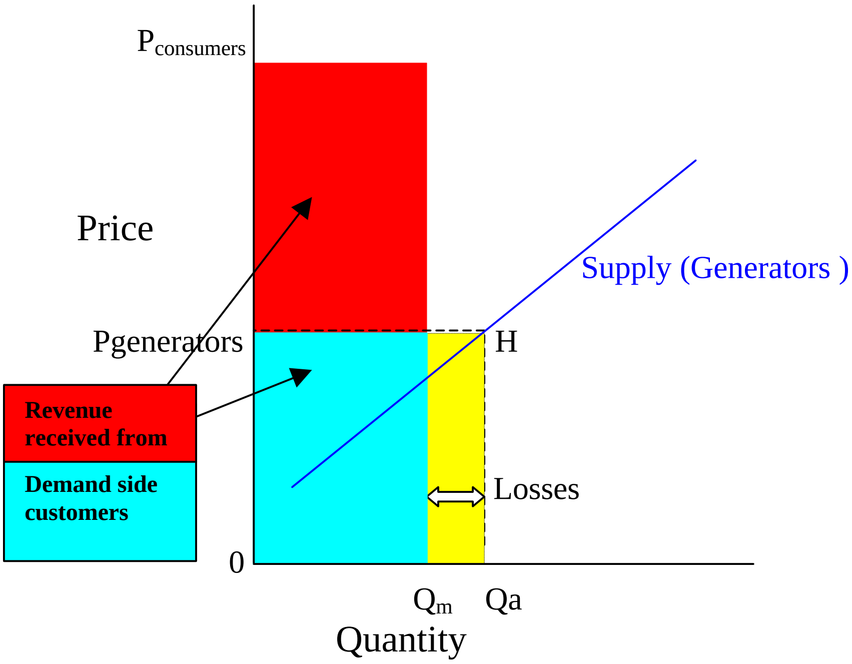
Transpower then uses this to define the Loss rental as

$P_B = P_A\ (1+ML)$
$Q_A = Q_B\ (1+AL)$

$$RENTAL = P_A \cdot Q_A \left[\frac{1+ML}{1+AL} - 1\right]$$

Where ML is the marginal losses, and
AL is the average losses, and
ML=2AL

Figure 10 Purchase of Losses and Recovery on Losses



The revenue received from the demand side customers is the red and blue area. Of this the amount paid to generators is the blue and yellow area. It can be seen that what is received from the demand side customers is more than is paid to generators. This is because the blue area is common to both receipts and payments and the red area is larger than the yellow area.

The Rental is the red area less the yellow area. This is the margin. This rental is the difference between what is recovered from consumers (red and blue areas) and the amount paid to the generators (blue and yellow areas which includes losses).

In respect of losses, the NZEM's net revenue for losses is thus the red area less the yellow area. It is then possible to graph the NZEM's average revenue and marginal revenue in respect of only the losses. This is done in the diagram below.

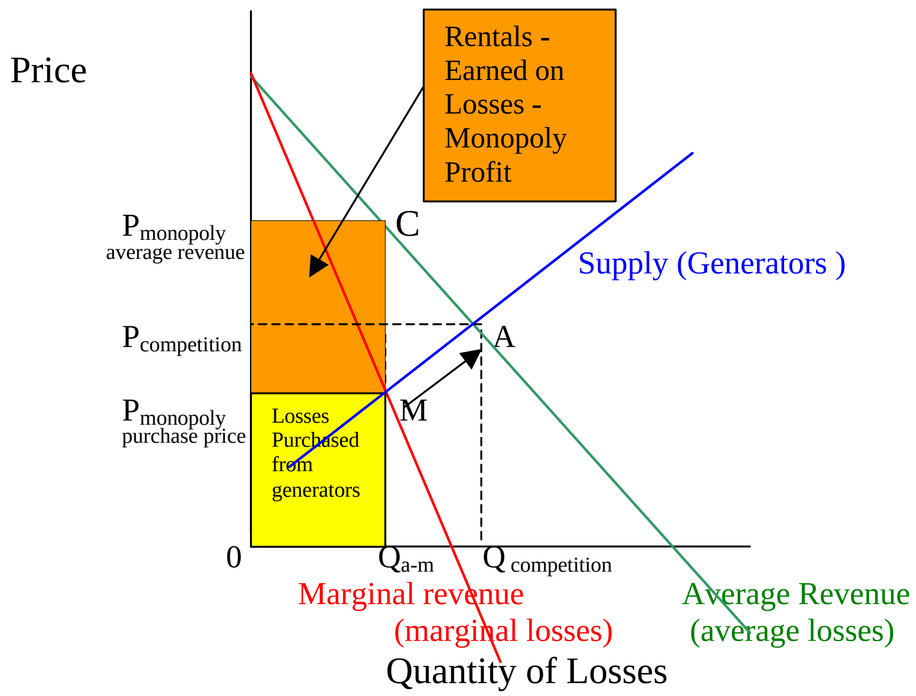
The NZEM purchase price per unit of losses is Pa (purchased from the generator). But instead of recovering only Pa from the demand side the NZEM recovers 100% more than Pa for the losses (because marginal losses are twice average losses). Thus average revenue recovered for losses is (see appendix 1 for mathematical derivation of formula)

$$AVERAGE\ \ REVENUE\,(Losses) = \frac{P_A ML}{AL}$$

The yellow area in the diagram below represents the losses purchased by the NZEM from generators and is the same as the yellow area in the diagram above. The orange and the yellow areas together in the diagram below are equivalent (in total dollars) to the red area in the above diagram.

The NZEM thus pays the generators the price, $P_{\text{monopoly purchase price}}$ for the losses and then recovers an average net revenue of $P_{\text{monopoly average revenue}}$ and in the process earns a rental or margin above cost of 100% (see appendix 1 for mathematical proof of 100% margin).

Figure 11 Monopoly Rental made by NZEM using Marginal Loss Pricing



$P_{\text{monopoly average revenue}}$ is the average revenue the NZEM receives for the losses

$P_{\text{monopoly purchase price}}$ is the NZEM purchase price of generation

$P_{\text{competition}}$ is the average revenue the NZEM would receive for losses if there were competition. This is also the average revenue and equilibrium price received by generators and the equilibrium price the demand side will pay for losses if allowed to enter the losses market and compete.

The NZEM buys the electricity from the generators at $P_{\text{monopoly purchase price}}$ and sells the electricity at a higher price $P_{\text{monopoly average revenue}}$ and is thus able to make a Rent.

If competition was allowed in respect of purchasing losses, the generation price would be bid up to $P_{\text{competition}}$. At this price the generators at this node will offer more generation. The increased generation however will only be demanded by customers at a lower price and hence both the demand and supply pay the same price for the losses. The loss rental is reduced to zero and no margin is made on losses and no monopoly profits are made.

Competition in respect of purchasing losses could occur in a number of ways. Firstly competition could be allowed between markets. In other words if there were a number of markets such as the NZEM. The market with average losses will ultimately end up with more generators and customers because the majority of customers and generators are better off with average losses.

Secondly, retailers and customers on the demand side could be allowed to purchase generation at the generator's GXP and then transmit the generation back to their demand side GXP on the basis of actual costs for the losses.

Thirdly, generators could be allowed to transmit their generation at cost (actual losses) and then sell their generation at the demand side GXPs.

Fourthly, the NZEM could stop adding any margin to the actual cost of losses by simply changing to an average loss model. This latter option is the quickest and easiest to implement.

The real problem however is that when a dominant or monopoly market is created these kinds of inefficiencies and problems tend to be a recurrent theme.

5.3 Under Utilisation of Transpower Network and Wasteful Investment in Transpower

Because marginal losses are technically close to twice average losses, a price model that uses marginal losses as opposed to actual losses, will therefore be more sensitive to changes in power flow. In other words the rate of change of price with respect to any given change in power flow will be greater for a marginal price model.

In physical terms this means that there is a disincentive to use the actual full capacity of any line. This is a result of pricing on marginal use rather than on actual use.

The marginal model will result in the Transpower grid being relatively under utilised in direct proportion to the difference between marginal and actual losses. This is illustrated graphically below.

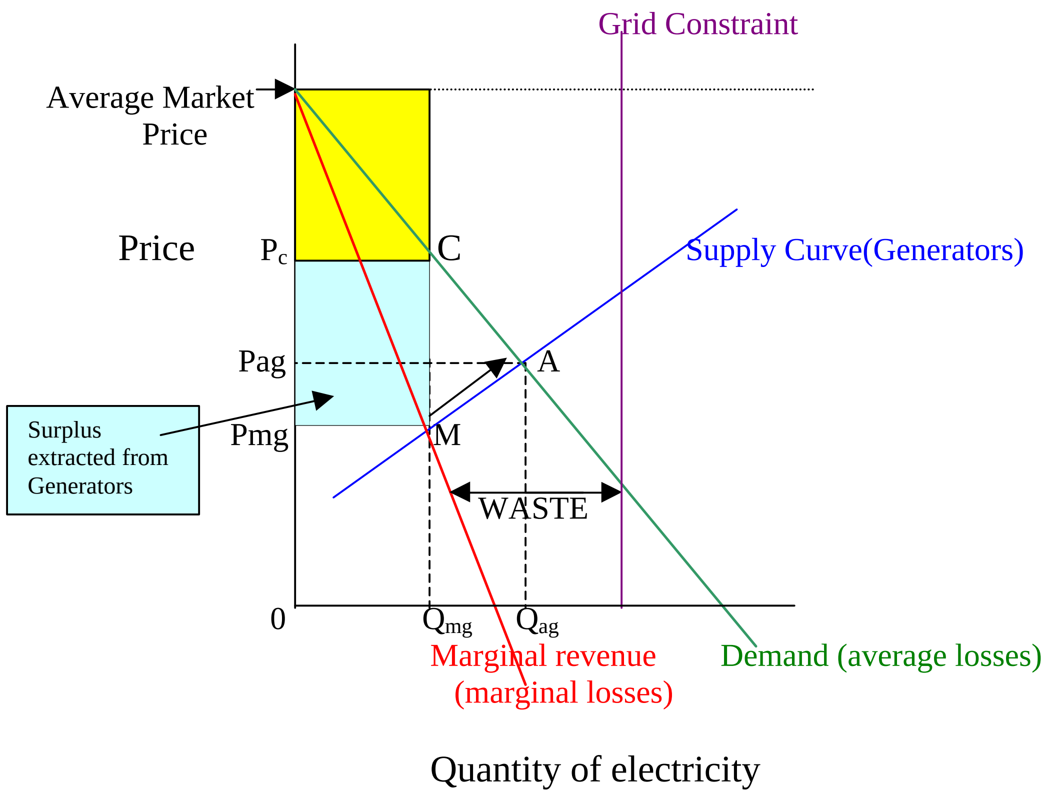
Because marginal losses will always be close to twice average losses, marginal loss pricing will drive the GXP price towards a zero or negative price at much lower electricity volumes than under an average losses model (see diagram below). There is no incentive to use the volume of grid capacity designated "waste" because the NZEM (using marginal losses) only gives generators the marginal loss price. The marginal loss price can also be seen to go negative far sooner than the average loss price. Most generators will stop generating long before the price gets to zero.

When Transpower build a network their objective should be to get maximum utilisation of the assets employed within their security criteria. Under a marginal pricing model Transpower will never be able to obtain optimum utilisation of its network because users will always have a price incentive to stop using the grid long before the actual losses become a problem. The result is that assets will never be fully utilised. Under utilising assets simply because of a pricing mechanism is wasteful. This is an example of how monopoly profits in

a related market (namely the NZEM) creates a misallocation of resources in another related market.
Transpower being a monopoly has the ability to pass on the costs of the under utilisation of assets to users of the grid through higher unit charges. Generally therefore it is generators and consumers that will pay these additional Transmission charges.

Consumers and generators therefore pay not only higher energy charges under marginal price, but also higher transmission charges under a marginal losses model.

Figure 12 Supply Side View of the Price Differential Caused by Losses at a GXP in a net generation region



Price of Pmg is charged using a marginal losses model (current NZEM model)
Price of Pag is charged using an average losses model
Actual (Average) Losses are the yellow area

Although actual losses are the yellow area and the NZEM should pay the generation region P_c it instead pays a far lower price of Pmg. The difference in price between P_c and Pmg is the additional surplus extracted (blue area) because the NZEM prices all units as if all units caused the marginal loss rather than what actually happens which is that only the last unit causes the marginal losses. At a NZEM price of Pmg, generators supply curve shows that they can only generate Q_{mg} . If the NZEM had used average losses then the generators would supply Q_{ag} .

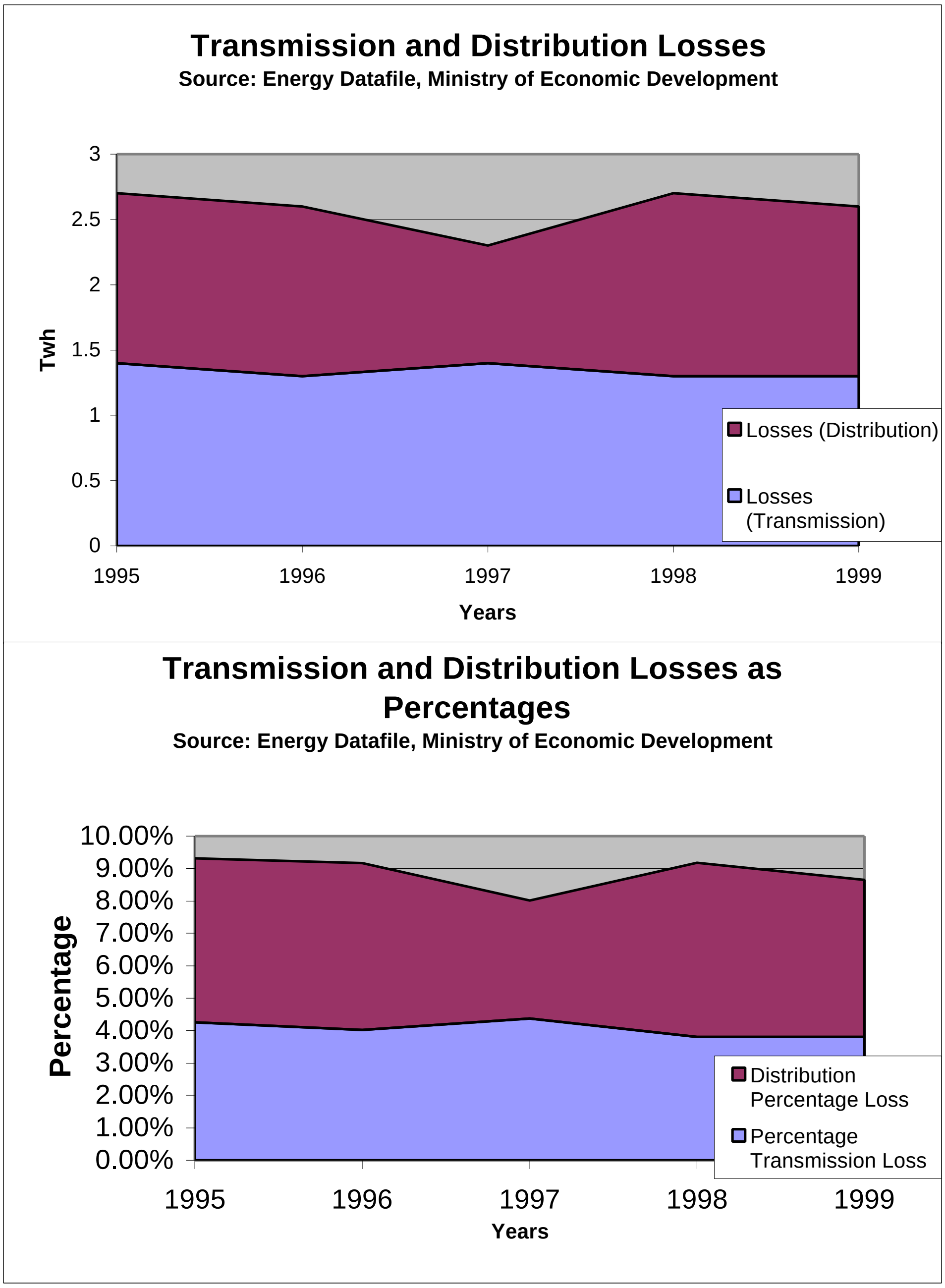
The generation capacity between Q_{mg} and Q_{ag} is wasted because it will not be dispatched by the marginal NZEM model. In the present energy crisis this has been very graphically illustrated by Taranaki and Huntly thermal stations not being used to capacity despite there being very low lake levels in the South Island and there being spare capacity on the DC link (see section 4 Practical Everyday Impact).

The marginal loss model is thus causing multiple waste at the generation level, transmission level and at the consumer level.

5.4 Barriers to Reducing Losses and Overcoming Constraints - Distributed Generation

Losses in New Zealand are substantial 2500 GWh (8% of consumption). Generation closer to the demand centers will reduce losses significantly. Losses are literally burning money as electricity is turned into heat and lost.

Figure 13 Transmission and Distribution Losses



2500 GWh of electricity is worth $250 million per year at around current prices of $100/MWh, and $125 million at $50/MWh. Because losses are energy that is turned into heat and truely lost to everyone, the full amount of losses reduces GDP and the standard of living.

Any reduction of losses will therefore increase GDP. The amount of the increase in GDP will be equal to the amount of losses multiplied by the GDP multiplier (which should be around 3).

5.4.1 Distributed Generation

In terms of the reduction of losses the most efficient generation is situated at the site of the demand load because this reduces losses to an absolute minimum. This generation is referred to as distributed generation or embedded generation and includes co-generation plants which are factories that generate electricity and use the waste heat for industrial processes at high overall energy efficiencies of up to 70-80 percent.

The Inquiry into the Electricity Industry (June 2000) has recognised that although distributed generation reduces losses and thus overcomes constraints, it is currently not able to gain the benefits of avoided transmission costs and has stated

246. Distributed generation is small scale generation located in the distribution network. By locating closer to demand, distributed generation reduces electricity line losses, thereby reducing the need for generation capacity.
247. Distributed generation should be able to:

- *………*
- *be paid the transmission costs avoided by virtue of being located within the network. Inquiry into the Electricity Industry: June 2000 Report to the Minister of Energy, para 246-247.*

Electricity Inquiry (2000) has gone further, and as one of its recommendations stated

250. In addition to these specific measures, many of our recommendations earlier in the report are likely to contribute to higher energy efficiency and better environmental impacts:

- *………*
- ***establishing a methodology to pass the benefits of avoided transmission charges through to distributed generators.** Through distributors paying avoided cost to distributed generation for relieving grid constraints, greater use of distributed generators can be expected in the future. This may reduce electricity losses and the use of fossil fuels for generating electricity. (Inquiry into the Electricity Industry: June 2000 Report to the Minister of Energy, para 250)*

Internationally the benefits of distributed generation are also recognised. The OECD recommendation to the OECD Council and Governments, including New Zealand, dated April 2001 page 19 specifically comments on distributed generation

***“...**small generators located at or near large electricity consumers (known as embedded or distributed generation) are an important substitute for transmission services, especially near bottlenecks on the transmission network.*

The FTC (Federal Trade Commission) notes:

“ A regulated for profit (separated transmission company) may refrain from taking actions that would increase competition between transmission and generation alternatives (for example, in addressing load pockets). To a considerable degree, expansion of transmission capacity and new or expanded generation within a load pocket are substitutes for each other in relieving such load situations... The competition danger is that the (separated transmission company) may have incentives to favour its own transmission assets relative to any generation source, thereby discouraging new generation sources in the load pocket. For example, the transmission company could delay connecting a new generator to the grid within the load pocket. By taking such an action, the Transmission Company could collect the maximum transmission rates for more hours per day and for longer than it would otherwise because of the increased use of its transmission capacity from outside the pocket”

Recommendation to the OECD Council and Governments, dated April 2001, page 19.

Distributed generators such as a reliable cogeneration plant are effectively substitutes for transmission and may reduce the income of both distribution line companies and Transpower. Hence the line network companies have an incentive to reduce distributed generation’s economic viability. Forcing distributed generators to pay for Transpower grid services, even when the distributed generator can supply this same service itself, makes the distributed generation less economic. Hence, competition to supply consumers with Transpower interconnection services is prevented.

In New Zealand at present the benefits of avoided transmission charges that result from distributed generation are tightly controlled by local distribution companies and Transpower.

Transpower contracts only with local distribution companies for transmission interconnection (grid) services. Transpower refuses to contract directly with distributed generators for the avoided transmission savings. The effect of this is that distribution line companies are made indispensable to the gaining of Transmission savings. This effectively gives distribution companies a monopoly in transmission savings. Distribution line companies then use their local line monopoly to prevent distributed generators obtaining transmission savings unless the distribution company receives the bulk of the savings.

Because Transpower contracts exclusively with distribution line companies for the resale of Transpower interconnection (grid), the only way a distributed generator can obtain transmission avoidance savings is by building new lines to customers. This duplicates the distribution lines of the line company. Distribution line companies in turn will not allow use of their own distribution lines for embedded generation to sell electricity to local consumers unless the embedded generator also pays for Transpower interconnection grid services. Thus by bundling distribution and Transpower charges, distribution line companies prevent embedded generators gaining the benefits of any grid transmission savings. Distributed generation is thus made less economic and this significantly reduces the viability of distributed generation.

When a distributed generator approaches a distribution line companies for transmission savings the line company is able to extract the bulk of the benefits, because the line company has the monopoly in transmission savings. This currently results in line companies extracting millions of dollars without any risk or investment.

New Zealand industry has attempted to develop around 500-1000 MW of distributed generation in the last few years but have been prevented from doing so largely because they have not been able to gain the full benefits of distributed generation. Todd Energy on its own has attempted to negotiate with line companies to build 100-200 MW of distributed generation. Without exception the line companies have either refused to negotiate (in the hope that the project is built in any event, and then the line company gets all the transmission savings) or the line companies have demanded the lions share of the avoided transmission charges.

For this reason the Commerce Commission have previously stated that Transpower's contracts with distribution line companies are
"*prima facie a contract which has the effect of substantially lessening competition in the delivered electricity market ..*"
Commerce Commission Report, October 1997, page 8

Other than this statement the Commerce Commission have not acted to allow transmission savings to be equitable obtained by distributed generators. The government to-date has also refrained from instructing its subsidiary, Transpower, to give equal access to transmission savings to that currently granted to distribution line companies.

The result, is that location pricing signals for the siting of new generation continue to be significantly distorted. This has aggravated grid constraints and prevented a lot of efficient generation from being built. If the network companies had not used their monopoly to prevent industry and other generators building distributed generation a significant amount of additional capacity would have been available. This additional generation would have lessened the dependence of the country on the large hydro schemes and would have substantially avoided the current electricity crisis. Industry, in particular, would have had the opportunity to be self sufficient instead of being exposed to the excessive spot prices over the last winter.

6 CONCLUSION

Using marginal losses as opposed to average losses is causing significant ongoing waste at multiple levels of not only the electricity market but in related markets.

It is further increasing the average market price. Consumers paying significantly higher prices. But nevertheless despite the average market price being higher, generators as a total group are not receiving these higher prices and in fact receive lower prices under marginal pricing. The NZEM is thus extracting a margin from both consumers and generators and retaining this.

The rentals retained by the NZEM has been shown to be equivalent to a monopoly rent. One of the basic tenants of economics is that monopoly profits causes a distortion in resource allocation and dead weight welfare losses. The current state of the NZEM and the continual wastage of water and thermal generation even while in the middle of an energy crisis is in fact a good real life example of what happens when the basic fundamentals of economic science are ignored.

Whatever way losses are looked at similar conclusions are drawn.

Marginal losses can be looked at as a simple margin. The actual margin is 100% on the cost of losses. This is effectively a broking margin because the NZEM is simply buying at one price and selling at another. A 100% broking margin on actual loss costs is a very large margin by any measure. Logic would suggest that this is bound to have an impact.

Because trade can only occur by incurring this 100% broking margin it is effectively a tariff barrier. As with all tariff barriers the added cost of the margin reduces trade. This means that generation is reduced and competition is reduced. If the objective of the market was to increase competition then the marginal losses are preventing the achievement of this objective.

The ensuing reduction in competition between generators is not only reducing the total volume of generation which pushes up price, but the marginal losses is preventing effective price competition even between those generators that do decide to generate. Thus for example, during July and the first half of August, in the middle of a serious water shortage, Huntly and Taranaki are still receiving the price signal to cut back production while the South Island hydro is receiving a high price signal, which is a price signal to generate and use precious water reserves.

A key conclusion of this paper is that each day of the continuing low lake levels, while the NZEM continues to use marginal losses, 150-200 MW of thermal generation is being priced to cut back during the day because they get too low a marginal price. At the same time, South Island lakes are being given a very high price during the day and are consequently using their scarce water. The reason the South Island generators would be reluctant to shut their generation is because if they did the South Island marginal price would increase significantly and the marginal price difference between the North Island and South Island would increase. Thus the South Island is effectively prevented from importing marginal amounts of electricity without paying a very high premium for this imported power. This is yet again a very good example of the "tariff barrier reducing trade" concept discussed earlier. The South Island is reluctant to import incremental power because of the high marginal price of doing so and the North Island is reluctant to export the power because it is penalised so heavily at the margin for doing so.

Actual losses have after all been used for decades prior to October 1996 and are still used by the distribution line companies today. Changing back to average losses is a very simple exercise and only requires average losses to be substituted for marginal in the NZEM formula (see appendix 1 and 2).

If Treasury and other forecasts prove correct, the real problem might be next year. If the lakes do not fill then it means that next winter will be commenced with lakes at even lower levels than this year.   Any delay in changing from marginal back to average losses will mean yet a further year of tariff barriers. This will continue to cause reduced thermal generation, further wasting of scarce hydro generation, unnecessarily high prices and seriously increase the risk that next winter the energy crisis could be even worse.

7 APPENDIX 1

Trans Power's Methodology

Trans Power in their publication Transmission Rentals explains the concept of Loss Rentals as follows: (*Trans Power, Transmission Rentals, Information booklet from The Transmission Services Group Trans Power, page 4)*

Where power flows from A to B

$$\mathbf{P_A\ Q_A} \longrightarrow \mathbf{P_B\ Q_B}$$

Where P_A and Q_A are the price and quantity respectively at node A and
P_B and Q_B are the price and quantity respectively at node B

Trans Power then uses this to define the Loss rental as

$$P_B = P_A(1+ML)$$

$$Q_A = Q_B(1+AL)$$

$$Q_B = \frac{Q_A}{(1+AL)}$$

$$Losses = Q_A - Q_B = AL \cdot Q_B$$

$$= \frac{AL \cdot Q_A}{(1+AL)}$$

$$RENTAL = P_A \cdot Q_A\left[\frac{1+ML}{1+AL} - 1\right]$$

Where ML is the marginal losses, and
AL is the average losses, and
ML is approximately twice AL

Cost of purchasing the losses ($AL \cdot Q_B$) is $P_A(Q_A - Q_B)$.

The Margin made on the losses (AL) is the profit or Rental.

$$RENTAL = P_B \cdot Q_B - P_A \cdot Q_A$$

$$RENTAL = P_A \cdot Q_A\left[\frac{1+ML}{1+AL} - 1\right]$$

Revenue received from the losses is the

Total Revenue (for LOSSES only) = Cost + Rental

$$= P_A\left(Q_A - Q_B\right) + P_A \cdot Q_A\left[\frac{1+ML}{1+AL} - 1\right]$$

$$= P_A \cdot Q_A - P_A \cdot Q_B + P_A \cdot Q_A\left[\frac{1+ML}{1+AL}\right] - P_A \cdot Q_A$$

$$= -P_A \cdot Q_B + P_A \cdot Q_A\left[\frac{1+ML}{1+AL}\right]$$

$$Average\,\mathrm{Re}venue(Losses) = Total\,\mathrm{Re}venue(for\,Losses\,only)/Losses$$

$$Losses = Q_A - Q_B = AL \cdot Q_B$$

$$= \frac{AL \cdot Q_A}{(1+AL)}$$

$$AVERAGE\ REVENUE\ (Losses) = \frac{-P_A \cdot Q_B(1+AL)}{AL \cdot Q_A} + \frac{P_A \cdot Q_A(1+ML)}{AL \cdot Q_A}$$

$$= \frac{-P_A \cdot Q_B(1+AL) + P_A \cdot Q_A(1+ML)}{AL \cdot Q_A}$$

$$= \frac{P_A\left[-Q_B(1+AL) + Q_A(1+ML)\right]}{AL \cdot Q_A}$$

$$= \frac{P_A\left[-Q_A + Q_A(1+ML)\right]}{AL \cdot Q_A}$$

$$= \frac{P_A Q_A\left[(1+ML) - 1\right]}{AL \cdot Q_A}$$

$$= \frac{P_A\left[(1+ML) - 1\right]}{AL}$$

$$= \frac{P_A \cdot ML}{AL}$$

It is thus possible to graph the losses purchased, P_A and the average revenue that the NZEM receives from losses

As the losses are purchased at the price of $\mathbf{P_A}$ and the marginal losses (ML) are approximately twice average losses (AL), it means that the average revenue (Losses) is twice as large as the purchase price $\mathbf{P_A}$ of losses and hence the margin made on losses is 100%.

$$AVERAGE\ \ REVENUE\,(Losses) = \frac{P_A ML}{AL}$$

$$AVERAGE\ PROFIT\ \ \%\ ON\,COST = \left[\frac{Average\,\mathrm{Re}venue}{Average\,Cost} - 1\right] * 100\% = \left[\frac{\frac{P_A ML}{AL}}{P_A} - 1\right] * 100\%$$

$$Since \quad ML = 2 \cdot AL$$

$$Therefore\ \ \ AVERAGE\ PROFIT\ \%\ ON\,COST = \left[\frac{\frac{P_A 2 \cdot AL}{AL}}{P_A} - 1\right] * 100\% = 100\%$$

8 APPENDIX 2

Mathematical Illustration Of Impact of Marginal vs Average Losses

Trans Power in their publication Transmission rentals explains the concept of Loss Rentals as follows.

Where power flows from A to B

$$\mathbf{P_A\, Q_A} \longrightarrow \mathbf{P_B\, Q_B}$$

Where P_A and Q_A are the price and quantity respectively at node A and
P_B and Q_B are the price and quantity respectively at node B

Trans Power then uses this to define the Loss rental as

$$\mathrm{Re}\,ntal = P_A \cdot Q_A \left[\frac{1+ML}{1+AL} - 1\right]$$

Where ML is the marginal losses, and
AL is the average losses, and
ML = 2AL

$$P_B = P_A(1+ML)$$

$$Q_A = Q_B(1+AL)$$

$$Q_B = \frac{Q_A}{(1+AL)}$$

The implicit assumption that generators will generate average loss quantities while receiving unassociated marginal loss prices is incorrect. Similarly this mistake is made for demand.

If a generator receives a lower marginal loss price P_A, then it will generate less than if it was getting a higher average loss price. Similarly, on the demand side consumers will demand less if they receive a higher marginal price than if they receive a lower average loss price. It is completely incorrect and invalid to assume that despite generators and demand getting a marginal price that they are going to act as if they had received some other price.

No generator therefore has an incentive to generate an average loss quantity such as Q_A because no generator receives an average loss price.

The nodal (GXP) prices in the NZEM model are based on marginal losses, and hence there can be no node (GXP) such as P_A Q_A . Generators are receiving marginal prices which are lower prices than average loss prices, and hence are generating lower quantities than Q_A. Hence no generator will ever generate the higher quantity associated with average losses Q_A. Therefore neither P_A nor Q_A can exist together at a real GXPs in the NZEM model.

Why it is important to appreciate this distinction is because there can NEVER be a generator which having received P_A would generate as if it was receiving a higher price based upon an average loss price. Only if the generator received the higher price based upon average losses would the generator actually generate Q_A**.**

In the current NZEM model there is only one theoretical point at which a generator would generate Q_A and receive $P_A = P_B /(1+AL)$, rather than $P_A = P_B /(1+ML)$, and that is at the average market price point.

As there is only one generator in our simplified example no generator can in fact be situated at this point[3]. The average market price point will in practice vary all the time and can in fact never be a stationary physical reference point.

The real grid is as follows:

$$\mathbf{P_{mg}\,Q_{mg}} \xrightarrow[\text{AL}=10\%]{\text{ML}=20\%} \mathbf{P_A\,Q_A} \xrightarrow[\text{AL}=10\%]{\text{ML}=20\%} \mathbf{P_B\,Q_B}$$

In order for there to be power flow on the grid, by definition generators must be at a location that is at some distance from the demand.

For simplicity, the net generation region is shown in the above diagram as one point mg (marginal losses priced generator) and the demand region B is shown as receiving P_B Q_B.

Quantity generated will be $\mathbf{Q_{mg}}$ NOT $\mathbf{Q_A}$

Marginal Loss Model (Current NZEM Model)

$\mathbf{P_{mg}}$ **=$41.67/MW**	$\mathbf{P_A}$ **=$50/MW**	$\mathbf{P_B}$ **=$60/MW**
$\mathbf{Q_{mg}}$ **=2200 MW**	$\mathbf{Q_A}$ **=2000 MW**	$\mathbf{Q_B}$ **=1818 MW**

Average Loss Model

Step 1 **Prior** to Generators Increasing Generation in response to the higher price offered

$\mathbf{P_{ag}}$ **=$45.45/MW**	$\mathbf{P_A}$ **=$50/MW**	$\mathbf{P_B}$ **=$55/MW**
$\mathbf{Q_{mg}}$ **=2200 MW**	$\mathbf{Q_A}$ **=2000 MW**	$\mathbf{Q_B}$ **=1818 MW**

Step 2 AFTER the Generator Increases Generation, the average market price drops

$\mathbf{P_{ag}}$ **=$43.64/MW**	$\mathbf{P_A}$ **=$48/MW**	$\mathbf{P_B}$ **=$52.8/MW**
$\mathbf{Q_{ag}}$ **=2310 MW**	$\mathbf{Q_A}$ **=2100 MW**	$\mathbf{Q_B}$ **=1909 MW**

[3] It should be noted that even if a second generator was introduced into this simple example, the mere siting of a second generator at the average price will, if both generators are running, shift the average price point closer to demand and away from the second generator. The point in the grid equal to the average price in fact shifts around each time demand and generation change.

Result after step 2 is

- **Prices are lower for consumers**
- **Generation prices in net generation regions increase**
- **Generation quantity increases and generation revenue increases**
- **Win - win**

The price at the generator will be

$$P_{mg} = P_A / (1 + ML)$$

An average loss model will yield a generator price of

$$P_{ag} = P_A / (1 + AL)$$

As ML is twice as high as AL. Therefore

$$P_{ag} > P_{mg}$$

As a generator will always generate a greater or at least equal quantity of generation at higher prices. The larger the number of generators there are, the greater the probability that a significant increase in generation quantity will occur at higher prices .ie.

$$Q_{ag} > Q_{mg}$$

Because the generation quantity of $\mathbf{Q_{ag}}$ is higher than $\mathbf{Q_{mg}}$, total generation available to the market increases. This has the effect of reducing the average market price increase i.e. $\mathbf{P_A}$ falls. This occurs because of both increased competition amongst generators for the higher price and also because demand will only take any extra generation offered at a lower price.

Similarly on the demand side currently is

$$P_B = P_A (1 + ML)$$

An average loss model will yield a demand price of $\mathbf{P_{ad}}$

$$P_{ad} = P_A (1 + AL)$$

$$As \qquad ML = 2AL \qquad or \qquad \frac{ML}{2} = AL$$

$$Therefore \qquad P_B > P_{ag}$$

Consumers therefore pay less, even PRIOR to any generation increase and when the average market price remains the same.

However in the dynamic real world as a result of the increase in the quantity of generation made availability, the average market price drops and the price to consumers falls further (step2). This means that $\mathbf{P_{ad}}$ falls further because the average market price falls due to increased generation (because generators get a higher price).

9 APPENDIX 3

Supply - Generators

On the supply side individual generators have a relatively elastic supply curve when the price is near their marginal cost. An individual hydro generator's marginal cost curve is an opportunity cost curve which changes depending on factors such as weather, storage and likely future prices[4].

With diverse generators, particularly generators with different types of generation such as hydro and thermal the supply curve for the different generators could be very different at various times. For the purposes of this analysis it will be assumed that a number of generators supply at a GXP, normal conditions apply, and that therefore the supply curve is reasonably elastic over the range of interest. However, different elasticities will not change the conclusions significantly.

The NZEM buys the generation at the generator's local GXP before any losses are incurred. From the generator's perspective then, the local GXP Price of injection is the price the demand side of the market will pay for its generation at that GXP at that time.

The losses occur after sale of the electricity to the NZEM at the GXP, and are therefore from the generator's perspective effectively part of the demand for the generation at the generator's local GXP.

In order to simplify the analysis into its component variables we shall first look at the demand and supply at a single GXP and assume that generation remains the same at each GXP and hence the average market price does not change. This is equivalent to assuming that the volume of generation at the GXP being analysed is not sufficiently large to make a significant difference to the average market price or generation dispatch. We are then able to illustrate the price impact of a change from marginal to average losses at a single GXP

[4] An interesting point that is particularly relevant for a country like NZ, which has a large amount of hydro capacity concentrated in the hands of a small number of generators, is that during a drought when there is little or no risk of spilling water even if rain is forecast, then the opportunity cost of generating will approach infinity. This is because in a drought using water for generation means that there will be less water for tomorrow. This will drive up prices and the generator knows this. With the prospect of prices in the future being even higher the cost of using water today is losing the opportunity of receiving even higher prices in the future. If in addition individual generators can set the price at close to their own opportunity cost then the market price will become an infinite recursive function because each time a generator uses each increment of water its opportunity cost increases and this is expressed in the market price. The higher market price then feeds back to increase the opportunity cost for the next time water is used to generate. The market price mechanism thus becomes a recursive loop with an exponential bias towards infinity. The only thing preventing prices going to infinity will be either intervention by either the dominant generators to cap their bids or regulatory intervention.

In the NZEM there are 4 large generators each with a percentage of total capacity which is larger than the excess generation available to the market during winter peak demand periods. Excess capacity available to the market at winter peak times is around 15%. Generators with capacity larger than 15% will be able to set the price as the market needs their capacity to fulfil demand. Meridian has 32%, Genesis 22%, Contact 22%, Mighty River 16% of capacity.

assuming all other things remain the same. A more complex dynamic analysis is discussed later.

The losses whether marginal or average are the difference between the price at the GXP and the average price in the market at any one point in time. As marginal losses defined by the principles of physics are close to twice average losses, the demand curves for electricity at the GXP seen by the generators can be drawn. If the NZEM model uses a marginal losses model the supply curve at the GXP will be twice as steep as the average losses supply curve.

As this generation GXP is assumed to not significantly influence market price, when generation volumes are zero the marginal and average losses will be zero and the GXP price will equal the average market price. As the generation volumes increase so will the losses and hence the price at the GXP will progressively decrease below the average market price. As generation volume increases the decrease in the GXP price will be twice the rate of decrease for each increment of volume when using marginal losses compared to average losses.

In other words generators would receive the average market price if losses were zero. But as losses are not zero they must receive a price which is lower than the average market price to effectively pay for their contribution to the losses to get the electricity half way to the demand side. The demand side effectively pay the cost to get the electricity the rest of the way. The theoretical half-way point is the average market price point.

The amount necessary to pay for the generators side actual losses is represented by the yellow area in the graph below. This area is the difference between the average market price and average losses at the demand side GXP. The generator is however paid a price lower than this.

The Price at the GXP under the existing NZEM market model is P_{mg} and the quantity supplied at this price is Q_{mg}.

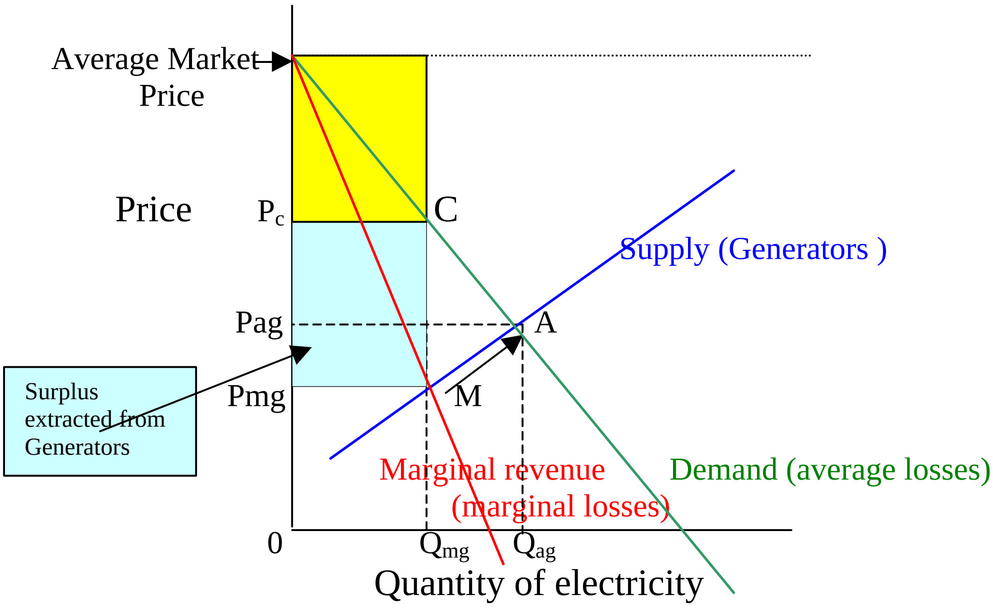
The Price at the GXP under an average price market model would be P_{ag} .

By changing from marginal to average losses at a GXP the price to the generator increases from P_{mg} to P_{ag} and the quantity demanded increases from Q_{mg} to Qag.

The generator's share of the actual cost of losses to effectively get the electricity to the average market price point is represented by the yellow area.

At P_{mg} a surplus is made because the price given to generators is below the price of actual or average losses. This forms the generator's contribution to what is essentially a monopoly profit and is represented by the area PcPmgMC .

Figure 14 Supply Side View of the Price Differential Caused By Losses at a GXP in a net generation region (Assuming No Dynamic Changes between Marginal and Average Supply)



Price of Pmg is charged using a marginal losses model (current NZEM model)
Price of Pag is charged using an average losses model

Price Differential = Price at a GXP – Average Price in the Market
Monopoly Profits (generators contribution) = PcPmgMC

Demand –Retailers and Customers

Every half-hour the NZEM sells to the demand side the amount of electricity required at the demand side GXP. Simultaneously the NZEM purchases the amount required by the demand side plus the actual losses (average losses) required to get the electricity from generators to the demand side. The amount necessary to pay for the demand side actual losses is represented by the yellow area in the graph below and is the same dollar cost as purchased from the supply side. This area is the difference between the average market price and average losses at the demand side GXP.

The NZEM effectively splits the cost of losses in half and charges half to the demand side and half to the generator side. In simple terms this is done by charging the demand side GXPs a higher price and the supply side GXPs are paid a lower price than the average market price. But instead of charging both the demand side and the generators for actual losses, the NZEM charges for marginal losses. Because the marginal losses are very close to twice actual losses (average losses) the NZEM recovers close to twice the actual costs. Close to twice as much as actual costs is recovered from supply side GXPs (by way of a lower price) and close to twice as much is recovered from the demand side.

The surplus is thus close to 100% above actual loss costs and is called a loss rental.

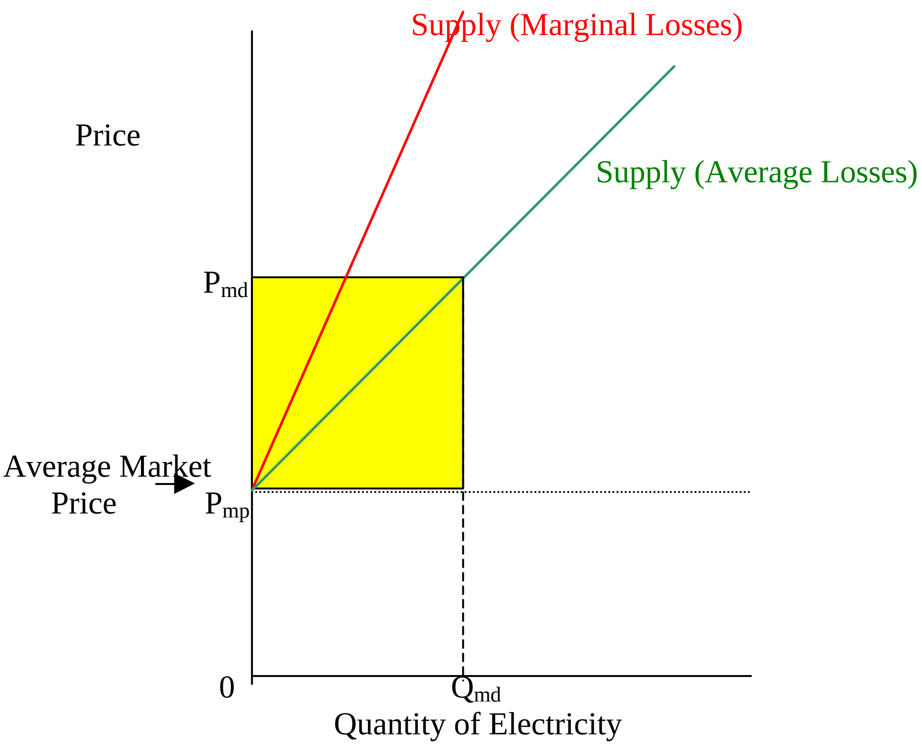
On the demand side, consumers and retailers tend to have a relatively inelastic demand for electricity in the short to medium term. Ripple control can moderate peak volume, and some large industries do cut back load and shift load into different time periods.

The losses whether marginal or average are the difference between the price at the GXP and the average price in the market at any one point in time. As marginal losses defined by the principles of physics are close to twice average losses, the demand curves of electricity at a GXP can be drawn.

When demand volumes are zero, both marginal and average losses will be zero and the GXP price will equal the average market price. As the demand volumes increase so will the losses and hence the price at the GXP will progressively increase above the average market price. As volume demand increases the increase in the GXP price will be twice the rate of increase for each increment of volume when using marginal losses compared to average losses.

Figure 15 Demand Side View of a GXP in a net Demand region

(For a given level of generation at a given average market price)



The Price at the GXP under the existing NZEM market model is P_{md} and the quantity demanded at this price is Q_{md}.

The Price at the GXP under an average price market model would be P_{Ad}.

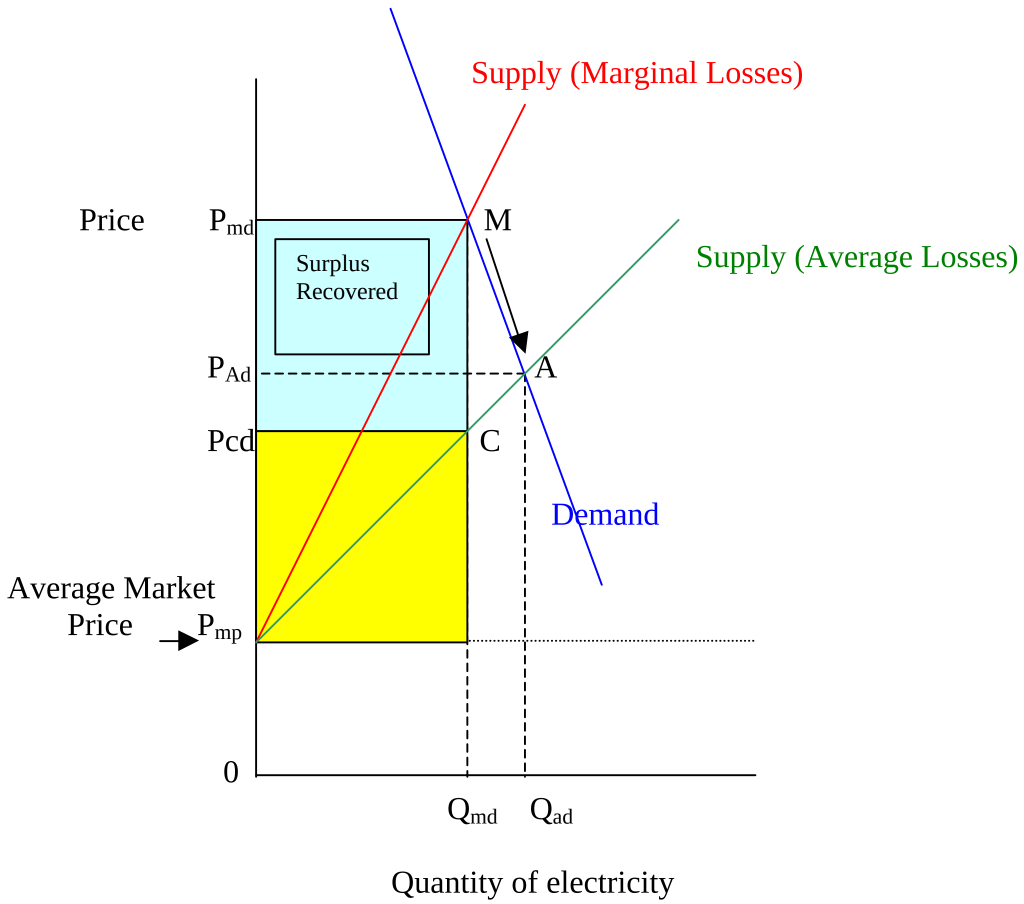
By changing from marginal to average losses at a GXP the price to the retailers and consumers drops from P_{md} to P_{Ad} and the quantity demanded increases from Q_{md} to Qad.

At P_{md} monopoly profits are made and are represented by the area P_{md} PcCM .

This is equal to the price at the GXP less the actual cost (actual losses) which are average losses multiplied by the quantity demanded at a price level of P_{md}.

Figure 16 Demand Side View of the Price Caused By Losses at a GXP in a net Demand region

(For a given level of generation at a given average market price)



Price of P_{md} is charged using a marginal losses model (current NZEM model)
Price of P_{Ad} is charged using an average losses model

Price Differential = Price at a GXP – Average Price in the Market
Monopoly Profits (demand side contribution) = P_{md} PcdCM

Dynamic Change

In the above graph it can be seen that generation responds to a higher price by generating higher volumes. In the previous static analysis it had been assumed that this increase by one generator was insignificant in terms of the overall market and that therefore market price did not change. Relaxing this assumption and including all generators at all GXPs means that if all generators see a higher price offered for their generation at their GXP for all volumes. In other words generators perceive the increase in market efficiency (i.e. removal of the 100% margin on actual loss cost) as an increase in the whole demand curve. Generators will make available more generation than before in all but the most extreme conditions (such as if there was market power).

In response to the higher price offered to generators at all GXPs, total generation increases. As in practice only the 100% margin has been removed and the actual demand curve at the demand GXPs has remained the same, the increased generation will have the effect of decreasing the average market price (again assuming no market power).

When the average market price falls (with no change in the consumer demand curve), the marginal and average loss curves must also fall as they are also a function of the average market price.

After these dynamic changes all net demand regions, under an average losses NZEM model, will see an even bigger decrease in price in comparison to the static analysis.

Similarly for net generation region GXPs the increase in total market generation offered into the market will be seen at each generators GXP as a decrease in demand for their generation at their specific GXP. Net generation regions under an average losses model will still see a net increase in price but it will not be quite as high as the average losses in a static analysis (shown above). The reason why all generators as a group must by definition get a higher price is because their supply curve has not shifted. In order to generate more they have simply shifted up their existing supply curves. Because the generators supply curves have not shifted, if generators only received the same price as before, then generators would not increase generation. Hence generators as a group must logically receive a higher price, even though total generation has increased. Generators total revenue will naturally also increase.

10 APPENDIX 4

The sensitivity of the wholesale price to demand levels

Time Weighted Average Price	$/MWh
25 July Final Price	413.97
5% Demand Reduction	327.27
7.5% Demand Reduction	283.34
10% Demand Reduction	249.90
15% Demand Reduction	201.25
20% Demand Reduction	153.68

NZEM Marginal Losses RD55731.DOC