Macquarie Generation

Corporate Office

34 Griffiths Road
LAMBTON NSW 2299

PO Box 3416
HAMILTON DELIVERY CENTRE
NSW 2303 AUSTRALIA

Telephone 61 2 4968 7499
Facsimile 61 2 0.9687433
Website www.macgen.com.au
ABN 18402 904 344

Dr Tom Parry
Chairman
Independent Pricing and Regulatory Tribunal
PO Box Q290
QVB Post Office NSW 1230

Dear Dr Parry

REGULATED RETAIL TARIFFS TO APPLY FROM 1 JULY 2004 TO 30 JUNE 2007

Macquarie Generation is pleased to provide the following submission to the Tndependent Pricing and Regulatory Tribunal's review of regulated retail tariffs for small electricity customers in New South Wales.

The terms of reference for the review include a number of references to the need for regulated tariffs to be set at cost reflective levels in order to encourage retail competition. Macquarie Generation supports the Government's decision to provide a regulated tariff as a default or safety net arrangement following the commencement of a new era in competition for household and small business consumers. Customers need time to understand the market, compare alternatives and to learn about the non-price protections available to all small retail customers. The offer of a safety net tariff may also encourage customers to test the retail market by providing certainty that they can return to the regulated tariff at any time. The Government is also concerned to mitigate sudden price rises for small retail customers as transitional tariffs move closer to fully cost reflective levels.

The timing of this review is crucial in terms of the development of a competitive retail market for NSW small retail consumers. The conclusion of the next IPART determination period in June 2007 will mark more than six years since the commencement of full retail competition in New South Wales. To date, the number of small retail custoiners switching to negotiated supply contracts has been relatively modest. This probably reflects, in part, the fact that retail competition remains an unfamiliar concept for most electricity consumers after a lifetime of monopoly supply. The market should continue to grow as residential and small business customers become more aware of their retail options,

PART is ultimately responsible for the success or otherwise of retail competition in New South Wales. The key determinant of switching behaviour for a homogeneous product like electricity will always be the price of any regulated alternative. If safety net tariffs are below the level at which retailers can provide competitive market offers, consumers will have no incentive to negotiate a commercial contract. Ensuring there is some scope for price discounts will encourage the entry of new retailers to compete with incumbent suppliers for a share of the three million residential and small business customers. This should have the further benefit of encouraging improvements and innovation in service delivery. Eventually, the presence of a vigorously competitive retail market may eliminate the need for tariff regulation.

Dr Tom Parry
Chairman
Independent Pricing and Regulatory Tribunal

This review provides the opportunity for IPART to set the foundations for a competitive retail market in New South Wales. The three-year determination period provides adequate time for PART to move all under recovering tariffs to cost reflective levels. Prior to the end of the next determination, the Government should be able to consider the scope for limiting the coverage of price regulation in the NSW retail market (eg, retaining price protection for residential customers on lower incomes).

In this context, Macquarie Generation has two key concerns that it would like to raise in response to the PART issues paper:

1. the need to apply an appropriate methodology for calculating the electricity purchase cost allowance in regulated tariffs; and
2. the importance of designing a tariff model that enables regulated tariffs to move to cost reflective target levels over the determination period.

ALLOWANCE FOR ELECTRICITY PURCHASE COSTS

The terms of reference for the review require PART to determine an allowance for electricity purchase costs based on an assessment of the long-run marginal cost of electricity generation, given the characteristics of the demand of customers remaining on regulated tariffs.

Load profile

Small retail customers on regulated tariffs have a much more volatile demand profile than those larger customers on commercially negotiated tariffs. This is important because the more volatile the pattern of consumption in a system the more reserve generation capacity required to supply customers during peak demand periods. It follows that the more reserve capacity required, the greater the overall cost of supplying total demand.

The 'load factor' is a commonly used measure of the 'peakiness' of consumption by a customer or a group of customers. The load factor for a group of customers is defined as total volume of consumption in a period divided by the sum of maximum hourly demand times the number of hours in that period. In effect, the load factor measures average demand divided by peak demand over a particular period of time.

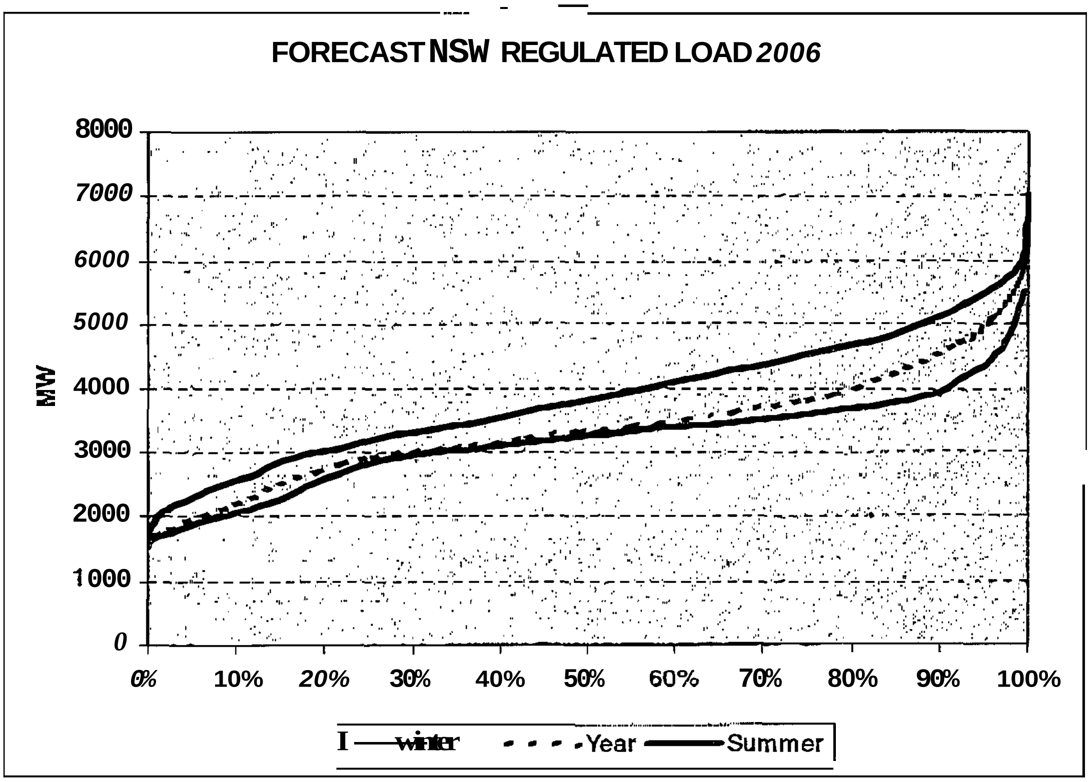
The lower the load factor the more volatile and peaky is the consumption profile. Macquarie Generation has calculated load factors for recent calendar years using NEMMCO data and regulated load information published by NSW Treasury. Separate load factors are shown for customers on regulated tariffs and commercially negotiated tariffs.

	2001	2002	2003
Regulated customers	49%	48%	48%
Commercial customers	75%	73%	71%

Residential and small business customers have a significantly more volatile load profile than commercial and industrial customers. This is not surprising given the demand characteristics of the different groups. Residential customers tend to consume the most during the early evening periods. Peak demands occur during the summer and winter peak periods driven by cooling and heating loads. Peak demand from larger commercial customers tends to be more evenly spread through the working weekday.

Dr Tom Parry
Chairman
Independent Pricing and Regulatory Tribunal

The following load duration curve shows the consumption profile of regulated customers. Macquarie Generation has based the profile on the regulated load volumes for 2001 as all residential and small retail customers were supplied under regulated tariffs during this period. Given that all small retail customers remain eligible for regulated tariffs, it seems reasonable to model possible load levels using this group of customers. Macquarie Generation has applied annual growth factors to forecast the 2006 load.



The load duration curve shows that some 2,250 MW (check) or more than 30% of regulated demand occurs in less than 10% of half-hour periods. Winter demand tends to be even more peaky than summer demand with approximately 1,000MW of consumption occurring in less than 2% of half-hour periods.

The level of peak demand sets the overall capacity requirements for the NEM. In addition, NEMMCO determines minimum system reserve requirements using forecasts of peak demand. Residential and small business customers are using a disproportionate share of system capability during these peak periods. New investment in generation assets to supply intermediate and peak loads will come at a higher unit cost than base load generation. Customers on regulated tariffs should pay an electricity allowance that reflects the costs they are imposing on the system.

Long run marginal *cost* of generation

Long run marginal *cost* can be defined as the 'incremental cost of all adjustments in the system expansion plan and system operations attributable to an incremental increase in demand which is sustained into the future' (Munasinghe and Warford 1982)[1].

[1] Munasinghe, M and Warford, J. (1982), *Electricity Procing: Theory and Case Studies*, World Bank, John Hopkins University Press, Baltimore and London.

Dr Tom Parry
Chairman
Independent Pricing and Regulatory Tribunal

The short run marginal cost represents the cost of producing an additional unit of electricity when the capacity is fixed. It includes the cost of fuel and operating costs related to the production of an additional unit of energy. Long run marginal cost includes the development cost of new capacity, and is therefore more complex to compute. As noted by Stefanou (1989):

> All economic activity occurs in the short run. The long run refers to the firm decision making planning ahead to select a future short-run production situation. The long run consists of the range of possible short-run situations available to the firm. As such, the firm operates in the short run by plans for the long run. The conditions occurring during the planning horizon are ignored with the focus on the conditions prevailing once long-run equilibrium is achieved?

The purpose of using the long run marginal cost of electricity in regulated tariffs is to promote economic efficiency. As Munasinghe and Warford argue:

> A tariff based on LRMC is consistent with the first objective of efficiently allocating resources. The traditional accounting approach is concerned with recovering historical, or sunk, costs. In calculating LRMC the important consideration is the amount of future resources used or saved by consumer decisions. Since electricity prices are the amounts paid for increments of consumption, they should generally reflect the incremental cost incurred. Supply costs increase if existing consumers increase their demand, or if new consumers are connected to the system. Therefore, prices that act as a signal to consumers should be related to the economic value of future resoures required to meet consumption changes. The accounting approach that uses historical assets and embedded costs implies that future economic resources will be as cheap or as expensive as in the pasr This could lead to overinvestment and waste, or underinvestment and the additional costs of unnecessary scarcity.'

When calculating the long run marginal cost, the costs associated with the existing power system should be ignored. As Kahn notes:

> Marginal costs look to the future, not to the past it is only future costs for which additional production can be causally responsible; it is only future costs that can be saved if that production is not undertaken. If capital costs are to be included in price, the capital costs in question are those that will have to be covered over time in the future if service is to continuc to be rendered. These would be the depreciation and return (including taxes) of the future investments that will have to be made. These incremental capital costs per unit of output will be the same as average capital costs of existing plant only in a completely static world, and under conditions of long-run constant cost. As for the former and by far the important qualification, in a dynamic economy, with changing technology as well as changing factor prices, there is every reason to believe that future capital costs per unit of output will not be the same as the capital costs historically incurred installing present capacity!

The calculation of the capacity cost component of long run marginal cost is dependent on assumptions over the cost of new capacity, its longevity, depreciation and on the discount rate to be applied over the life horizon of the investment. The depreciation rate represents the loss of value of the installed capacity over the years and the discount rate is the opportunity cost of capital that is used for the investment in new capacity.

---

[2] Stefanou, S. E. (1989), 'Returns to Scale in the Long Run: The Dynamic Theory of Cost', *Southern Economic Journal*, vol. 55, no. 3, pp. 570-579, at p. 570.
[3] Munasinghe, M and Warford, J. (1982). *Electricity Procing: Theory and Case Studies*, World Bank, John Hopkins University Press, Baltimore and London, p. 11.
[4] Kahn, A. (1988) *The Economics of Regulation: Principles and Institutions.* Massachusetts Institute of Technology, vol. 1, p. 98.

Porat, Irith and Turvey (1997)[5] outline a number of steps in the calculation of long run marginal generation costs:

1. Forecasting likely increases in system load and the timing of the forecast demand increases. The load changes can be modelled for different groups of demand periods – peak, off-peak and shoulder for winter, summer, spring/autumn;
2. Calculating optimal system expansion plans using dynamic programming to minimise the total system costs of meeting the anticipated increase in demand for each group of demand periods. Requires detailed information on fixed and variable costs of alternative plant technologies including information on reliability and operating characteristics. Fixed costs include capital costs for each plant type;
3. Starting with a base case, a load increment is added to each of the groups of hours. The .difference in the discounted amount of electricity provided is then divided into the difference between the discounted cost of the base plan and the discounted cost of the optimal plan for the altered load forecast to yield a marginal cost for that group of hours. An analysis of the change in production patterns under the base case and incremental scenarios will provide a breakdown of the marginal cost into capacity costs and variable costs for the increment in load.

In summary, the key messages in estimating the long run marginal cost of electricity are:

- all relevant costs are future costs, not those of the present system;
- the costs of incremental capacity required to meet incremental demand must be included;
- the difference between the net present value of costs associated with serving demand under a 'base case' (in this case, NEM demand minus the regulated customer load) and an 'incremental load case' (in this case, NEM demand plus the regulated load), divided by the net present value of regulated demand, needs to be calculated

Macquarie Generation estimates of generation costs

The above modelling approach requires a substantial quantity of data and the ability to calculate optimal system expansion plans, usually involving a linear programming model. Macquarie Generation has undertaken a simplified approach to the calculation of generation costs to supply the NSW regulated load. The one-year static modelling exercise assumes:

- Peak demand of 7,000 MW and average demand of 3,420 MW (see load duration curve above);
- Weighted average cost of capital of 10.5%;
- Maximum capacity factor for coal fired generation of 85%;
- 300 MW of reserve capacity allocated to the regulated load;
- Three alternative technologies – coal-fired, open cycle gas and closed cycle gas;
- costs

costs	Fixed costs	Variable costs
Coal fired generation	$1,455/kW	$14.50/MWh
Open cycle gas turbine	$688/kW	$74/MWh
Closed cycle gas turbine	$816/kW	$30/MWh

[5] Porat, Y, Irith,. R & Turvey, R (1997) Long-run marginal electricity generation costs in Israel, *Energy Policy*, Vol.25, No.4, pp.401-411.

Using the above assumptions, the least cost mix of plant technologies to supply the regulated load would be 3,800MW of coal-fired base load plant, 1,400MW of closed cycle gas turbine plant for intermediate generation and 2,100MW of open cycle gas turbine plant for peak requirements including 300MW for reserve capacity.

Based on chis mix of plant technologies and estimated output levels, Macquarie Generation has calculated a generation cost of $43.27 MWh with an additional cost for reserve capacity of $0.72 MWh. These estimates do not include the cost of supplying green energy to customers on regulated tariffs (see below). These costs are consistent with existing PART allowances for regulated electricity and with other empirical studies on the long run marginal cost of electricity generation in Australia.

While the Macquarie Generation modelling provides an indication of generation costs, more detailed analysis is required to estimate accurate long-run marginal cost numbers consistent with the methodology outlined above. Macquarie Generation understands that PART has engaged Intelligent Energy Systems to undertake this detailed work using the most recently available data.

Macquarie Generation notes that PART does not intend to publish the results of the IES study until after the due date for submissions. Given the importance of these estimates for the development of retail competition and the operation of the NEM more broadly, it is requested that an opportunity to comment on these estimates is provided before PART releases its Draft Report.

Green costs in regulated tariffs

The terms of reference require PART to consider an allowance for retailer compliance with any Commonwealth mandatory renewable energy target (MRET) requirements and the licence requirements relating to the NSW Greenhouse Gas Benchmark Scheme.

Macquarie Generation is a liable party under both the NSW greenhouse benchmarks scheme and the MRET scheme, with a substantial combined liability. Our estimates of REC and NGAC prices are based on our practical experiences in trying to source these certificates for future years. The underlying assumptions used to calculate likely green energy costs are detailed at attachment 1.

IPART's mid term review of regulated retail prices for electricity to 2004 (June 2002) referred to Government modelling of the combined compliance costs of the State and Commonwealth green requirements averaging $2.20 over a ten-year period. PART separately identified an average annual MRET compliance cost of $0.25 over the period to June 2004. PART mid term review stated that the LRMC allowance included provision for green energy costs in the range of $0.50 to $2.20 MWh.

Macquarie Generation anticipates a substantial increase in green energy costs over the next few years - from $1.45 in 2004 to $4.18 in 2007. This increase is driven by the progressive tightening of the MRET and NGAC obligations and the increasing cost of the remaining abatement and renewable energy measures.

$/MWh	*2003*	*2004*	*2005*	*2006*	*2007*
Renewable Energy Certificates	$0.37	$0.53	$0.70	$0.91	$1.10
NSW Greenhouse Benchmark Scheme	$0.23	$0.92	$1.57	$2.23	$3.07
Total	$0.60	$1.45	$2.27	$3.14	$4.18

The estimates of renewable energy certificate prices used in the assumptions are higher than other publicly available estimates, such as the studies commissioned by the Office of the Renewable Energy Regulator (ORER) by IES and MMA in relation to REC prices, and the NSW Government estimates of NGAC prices contained in the Sensitivity Modelling Report, prepared by Frontier Economics![6] It should be noted that all of these studies abstract From 'real world' issues such as complications and delays in becoming accredited, market power, and search costs, all of which have the potential to cause divergences between modelled prices and actual certificate prices.

The actual compliance costs with MRET and benchmarks obligations over the next three years are highly uncertain at chis time. The MRET scheme is still relatively new, and the MRET Review Panel recently recommended significant change to the MRET scheme. The Federal Government has yet to respond to those recommendations. In addition, the NSW greenhouse benchmarks scheme is in its infancy, with relatively few potential suppliers being accredited at this stage, The speed with which accreditation and certificate creation occurs could significantly affect the price of NGACs in the next three years. Large swings in the price of certificates are entirely possible in a new market, as participants take time to understand the scheme, and gain a better feel for whether they can become a certificate supplier, and where their competition lies.

IPART must ensure that the review provides sufficient allowance for the anticipated real increases in regulatory costs associated with green programs over the course of the next determination period. Standard retailers must be able to earn a retail margin that covers the cost of renewable energy and greenhouse abatement obligations.
Given the uncertainty associated with future green compliance costs, the most appropriate way forward may be for the Tribunal to review actual green energy costs as part of its annual approval of changes to regulated tariffs.

Hedging costs

The terms of reference state that in order to promote competition, regulated retail tariffs which are below the cost of supply should be moved towards full cost reflectivity, as far as practicable.

Hedging costs are a small but significant component of the costs of supplying domestic and small business customers under a commercial contract. Macquarie Generation is of the view that IPART should take account the costs of hedging electricity purchases in the setting of regulated retail tariffs to ensure competitive neutrality with commercial providers. Retailers

[6] IES 2002, *Modelling the Price of Renewable Energy Certificates, A* **Report to the Office of the Renewable Energy Regulator, December. MMA 2002,** *Modelling the Price of Renewable Energy Certificates Under the Mandatory Renewable Energy Target,* Report to the Office **of the Renewable Energy Regulator, 29 October, NSW Government 2002. Sensitivity Modelling: Greenhouse related licence conditions for electricity retailers, March.**

offering commercial contracts will find it difficult to compete with regulated tariffs if no account is given to the hedging costs incurred by retailers in managing electricity purchases.

Hedging costs refer to the various volume and forecasting risks, counter-party credit risks and transaction costs associated with purchasing electricity on behalf of retail customers supplied under commercial contracts. Retailers supply customers on commercial contracts must employ energy traders to manage these risks through financial hedge contracts. Such contracts include various risk premiums to manage uncertain outcomes.

As noted earlier, residential and small business customers have particularly volatile demand profiles. This combined with the coincidence of high residential demand with high NEM spot prices adds to cost of managing purchases for small retail customers under commercially negotiated contracts.

In the issues paper for the review, the Tribunal notes that "in other jurisdiction, an allowance for hedging is often included in the retail margin. In relation to electricity, the Tribunal has previously decided not to include hedging costs in the retail margin for NSW electricity retailers, as the Electricity Tariff Equalisation Fund provides a form of automatic hedging for retailers supplying customers on regulated tariffs".

For standard retailers supplying customers on regulated tariffs the Electricity Tariff Equalisation Fund does provide a low risk mechanism for managing purchase costs. The Fund is effectively guaranteed by the three NSW generators through the obligation to "top up" the Fund when there are insufficient reserves to offset retailer purchase costs. The Fund uses differences in the regulated energy cost and NEM spot price multiplied by regulated load volumes to calculate retailer payments to and from ETEF reserves. The ETEF mechanism ensures that standard retailers earn no more or less than the retail margin determined by IPART. Therefore, standard retailers would gain no artificial advantage in having a higher energy charge incorporated into regulated tariffs. They would earn no extra profits that could be used to fund lower prices to contestable customers, at the expense of other retailers.

A hedging cost allowance should be built into the ETEF regulated energy cost. This would ensure that retailers would continue to earn a margin that reflects actual risks and costs. A higher regulated energy cost would reduce the financial risks faced by generators in having to underwrite the operation of the ETEF arrangement.

Intelligent Energy Systems has previously undertaken work for the Victorian Government on standing tariffs for small retail customers using prevailing contract price information to determine an effective purchase cost component[7]. The model used total customer load, a load factor and a peak/total ratio to determine the load shape for small retail customers. While this was appropriate for Victoria, the NSW regulated load has significant differences, in particular energy consumption is highly sensitivity to weather through the heating and cooling load. This means that the bulk of regulated peak load is supplied in the winter and summer peak periods. These periods are also those that attract the highest contract prices. Applying the IES model in NSW would systematically under value the market price because it smooths peak energy across the year.

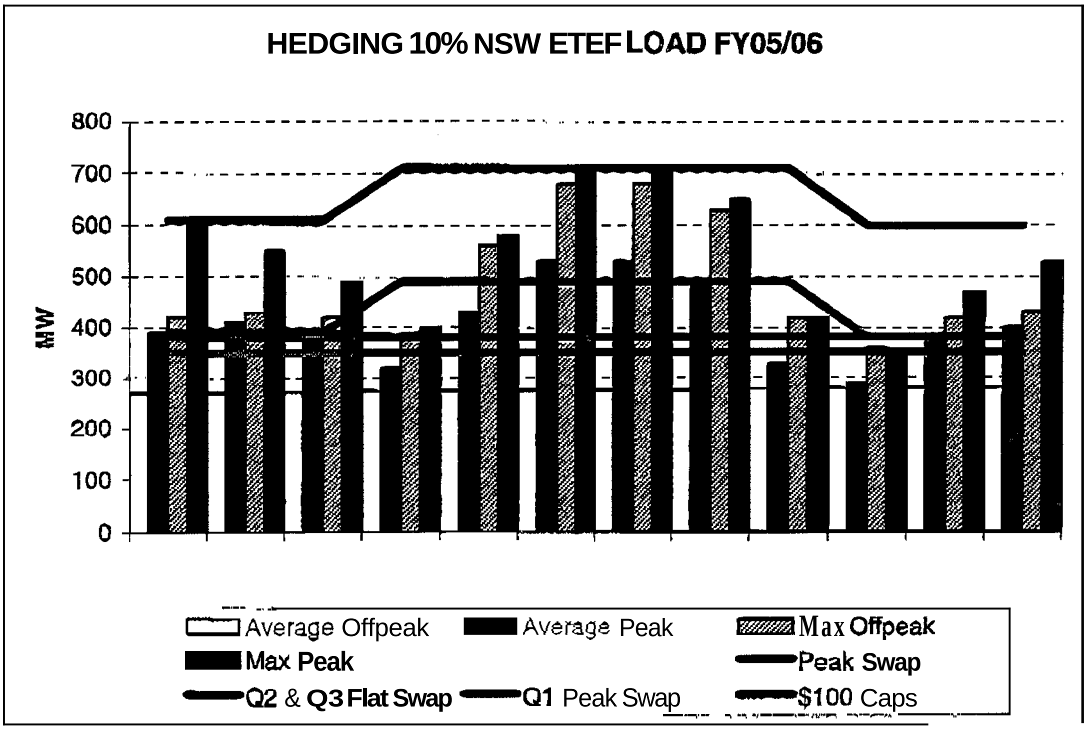
---

[7] Intelligent Energy Systems, 2001, Spreadsheet model prepared for the then Victorian Regulator General's review of retail prices tariffs for domestic and small business customers and deemed customers.

Dr Tom Parry
Chairman
Independent Pricing and Regulatory Tribunal

To avoid this bias, Macquarie Generation has developed a more detailed approach to estimate likely market purchase costs. The Macquarie Generation analysis assumes that a retailer is hedging 10%of the ETEF load profile (2,750 GWh) by buying a portfolio of flat and peak swap contracts, cap contracts and spot market purchases. The following table and diagram show the contract types, volumes and prices.

FY05/06 Flat Swap - 350 MW @ $36.00/MWHr
FY05/06 Peak Swap - 30 MW @ $50.00/MWHr
Q1 Peak Swap - 10 MW @ $70.00/MWHr
Q2 & Q3 Flat Swap - 110 MW @ $36.00/MWHr
FY 05/06 Flat $100 Cap - 220 MW @ $7.50/MWHr
FY 05/06 Pool Payments capped at $100 @ Ave $32.00/MWHr



The average hedge cost using the above combination of contracts is $49.63 MWh. The hedge market price is approximately $5 MWh above the ETEF regulated energy cost. Retailers offering commercial contracts would have to undercut the regulated tariff by negotiating a lower hedge price with a generator or trader, or by signing up a customer with a flatter, lower cost load profile.

Jurisdictional regulators in Victoria, South Australia and the Australian Capital Territory have incorporated hedging costs into the calculation of standard tariff offers for small retail customers. This probably explains why Victoria has experienced higher rates of customer switching since the Commencement of full retail competition in January 2002. While switching is not desirable simply for its own *sake,* it at least provides evidence that new entrants can profitably participate in the market, increasing the odds that at some point in the future, regulated tariffs may not be required at all (except perhaps for retailer of last resort situations).

Dr Tom Parry
Chairman
Independent Pricing and Regulatory Tribunal

FORM OF TARIFF REGULATION

The design of the next determination of regulated tariffs must ensure that all reasonable costs identified in the review are passed through to customers on regulated tariffs. The electricity allowance in regulated tariffs must not be the cost component that is squeezed to accommodate real increases in other legitimate retail costs. To do so would threaten the progress made to date with retail competition and deter any new investment in retail systems and marketing by new entrant retailers. It would also blunt the signals for new investment in generation capacity to supply regulated load over the next few years.

Recent history provides a good guide to the design failings of the current framework for adjusting regulated tariffs. The regulated energy cost that applies as the strike price for the calculation of ETEF payments increased by only 1 per cent in nominal terms in the period 2002-03 to 2003-04. This amounts to a 2 per cent real reduction in the electricity purchase cost in regulated tariffs despite an increase in energy allowance in target tariffs of 3% nominal. The reduction was driven by a real increase in distribution network charges over 2003-04 combined with **a global CPI *price* cap on the regulated tariffs offered** by standard retailers.

The recent IPART Draft Report, *NSW Electricity Distribution Pricing 2004-05 to 2008-09*, foreshadowed substantial real increases in network charges for all retail customers over the next five years. Network charges account for approximately 40% of the total regulated tariff charged to small retail customers. NSW regulated tariffs will need to increase on average by approximately 2.5% in real terms in 2004-05 to absorb the impact of higher network charges.

Proposed network charges	*Year 1 increase*	*5-year increase*
Energy Australia	*6.5%*	12.6%
Integral Energy	1.1%	*5.6%*
Country Energy	*6.5%*	17.6%
Australian Inland	*6.5%*	17.6%

The four NSW standard retail suppliers have all sought significant real increases in their retail cost allowances as part of the next retail determination. The IPART issues paper for *the* review includes a *summary* of retail operating costs and retail margins provided to electricity retailers offering standard supply products in other Australian jurisdictions (appendix 2, p.22). The current NSW regulated retail margin of $40-$60 for operating costs and 1.5 to 2.5% for a **retail margin are the lowest** of all **NEM jurisdictions and** less than the allowance provided for gas suppliers.

The setting of the regulated electricity allowance is the key factor in determining the scope for retail competition. The vast majority of non-energy costs are separately regulated and charged to small retail customers *at* a common rate irrespective of whether the customer receives supply under a regulated or commercial contract. The retail margin is the only other market component that retailers could adjust to attract customers. However, as noted above, regulated retail margins are already at low levels compared with retail margin allowances in other jurisdictions. Retailers offering commercial tariffs would also require an additional return to cover the costs and risks of hedging energy purchases.

At present, the scope far price discounts to attract regulated customers to a commercial tariff is limited or non-existent. The submissions of the four standard retailers to the IPART review indicate chat average regulated tariffs are set at levels below target tariff levels. Energy Australia states that its regulated retail tariffs are on average 1.7% or $18 million below target levels. Integral Energy provides a similar estimate of $20 million.

Any upward movement in forward hedge prices for electricity would further dampen the scope for retailers to negotiate price savings with small retail customers. Substantial increases in market prices could even trigger a return by small retail customers on negotiated contracts back to the standard form supply contract when existing contracts expire.

IPART must ensure there is a degree of neutrality between the commercial and regulated alternatives to provide some encouragement for retailers to develop and market commercial offers for small retail customers. Macquarie Generation proposes the following changes to regulated tariffs to ensure they are at target levels at the conclusion of the next determination period:

- an up-front and automatic pass through of any increase in monopoly network charges;
- phased increase over three years of any real increase in the retail cost of serve allowance or retail margins;
- phased introduction of a hedging cost allowance into the ETEF energy cost allowance over the determination period;
- annual review and pass through of green energy costs based on changes in market prices for RECs and NGACs.

SUMMARY

The Tribunal must not take the soft option of deferring difficult decisions on cost pass through by lowering the electricity allowance in regulated tariffs. Such a decision would stall any development of the retail market in NSW, a market that has failed to attract significant entry from new retail suppliers. More importantly, small retail customers should face tariffs that reflect the costs they impose on the generation sector. Price provides the most affective incentive for demand management. Equity concerns should be dealt with using direct and transparent mechanisms, not through the blunting of signals for new investment in generation facilities.

Macquarie Generation looks forward to the opportunity to comment on the cost modelling work by Intelligent Energy Systems and the Tribunal's draft report.

Yours faithfully

2/2/04

RUSSELL SKELTON
MANAGER MARKETING & TRADING

Attachment 1: New South Wales Benchmark Scheme – assumptions and data

		2004	2005	2006	2007
Inputs					
Required RECs	GWh	2600	3400	4500	5600
Australia total consumption	GWh	199,157	203,935	208.713	213,491
REC percentage		1.25%	1.67%	2.16%	2.62%
NSW total consumption	GWh	65,671	67,499	69,137	70,770
NSW per capita target	tonnes C02 per capita	8.31	7.96	7.62	7.27
NSW population	million	6.7521	6.7961	6.8510	6.9059
Pool coefficient	tonnes/MWh	0.906	0.906	0.906	0.906
Distribution loss factor		1.053	1.053	1.053	1.053
NEMMCO purchases	GWh	1,000	1,000	1,000	1,000
Calculations					
Total electricity sold	GWh	950	950	950	950
Electricity Sector benchmark	kTonnes C02	56,110	54,097	52,205	50,206
Greenhouse gas benchmark	kTonnes CO2	811	761	717	674
Deemed generator purchases	GWh	0	0	0	0
Total electricity purchased	GWh	1,000	1,000	1,000	1,000
RECs counted	GWh	13	17	22	26
Attributable emissions	kTonnes CO2	895	891	886	882
Attributable less benchmark	kTonnes CO2	83	130	169	209
Greenhouse shortfall	kTonnes CO2	83	130	169	209
Greenhouse shortfall	tonnes/MWh	0.088	0,137	0.178	0,220
Cost calculations					
REC rate assumed	$/M h	$40.00	$40.00	$40.00	$40.00
NGAC rate assumed	$/tonne	$10.50	$11.50	$12.50	$14.00