ENERGYAUSTRALIA

RESPONSE TO IPART'S DRAFT DETERMINATION

MAY 2007

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1 EXECUTIVE SUMMARY

EnergyAustralia welcomes the opportunity to make the following submission in response to IPART's draft Determination on regulated retail prices for 2007-10. EnergyAustralia applauds the work performed by the Tribunal hitherto. This draft Determination represents a vast improvement on the current Determination, particularly in relation to improved flexibility in the price-setting process and the pass through of network charges. We believe that, with some further refinements, the Determination should ensure the objectives underpinning the NSW Minister's Terms of Reference are delivered.

Energy cost allowance

Movements in the wholesale energy costs since IPART began their review far exceed the allowances in Frontier Economics' modelling. While the modelling was consistent with the observed market history at the time it did not adequately reflect the risks and consequently must be reviewed.

The volatility premium assessed by Frontier Economics' significantly understates the cost and risk associated with transacting electricity in the NEM by at least 80%.

The declining real price of electricity proposed by Frontier Economics' is inconsistent with other aspects of their modelling and must be amended to reflect an appropriate risk management premium.

Current level of retail competition

EnergyAustralia commends IPART for aligning its review of effective competition with the guidelines proposed by the AEMC. We broadly agree with IPART's findings on the level of competition.

Form of regulation

EnergyAustralia fully supports the Tribunal's draft Decision to move to a Weighted Average Price Cap with no restrictions on tariff movements. The Decision allows EnergyAustralia to deliver efficient pricing to all customers.

EnergyAustralia is in the process of broadening its hardship program. We believe a targeted approach to addressing the needs of vulnerable and low income customers is more effective than alternative measures such as bill constraints which are blunt instruments that poorly protect those to whom it is intended.

Retail cost and margin allowance

EnergyAustralia is satisfied that net margin allowance in the Tribunal's draft Decision delivers an appropriate transitional return to the standard retailers. We also appreciate the Tribunal's acknowledgement that standard retailers enjoy the cost synergies from a shared distribution / retail business – benefits not afforded to a MMNE as defined by Frontier Economics – and have consequently erred on the upper end of the range forecast provided by Frontier Economics.

We believe that Frontier Economics have over-played the prospects of labour productivity reducing a MMNE retailer's operating costs in the near future. The reality is that any perceived improvement in productivity will be more than outweighed by wage increases felt both in our industry and the broader economy. This cost pressure, on a labour-intensive retailing business, should serve to increase overall operating costs in real terms over the course of the 2007-10 Determination period.

Setting price controls

In assessing the appropriateness of the price controls, EnergyAustralia has reviewed the supporting price model developed by IPART and audited by Frontier Economics. EnergyAustralia believes the model is sound. However, we submit that the specific peak, shoulder and off peak R values are unnecessary and represent a backward step in the Tribunal's efforts to move toward a lighter-handed form of regulation. These individual price control values can simply be replaced by one, single R variable as per current practice. The absolute level of network charges should also be carefully assessed as this will influence the level of retail margin (set on a percentage of total N+R sales) embedded into the R values.

Non-tariff charges

EnergyAustralia is largely satisfied with the draft Determination on non-tariff charges. However, we continue to maintain that the late payment fee should be increased to $10, a level supported by industry observations and the work of our consultant, KPMG.

Weighted Average Cost of Capital

EnergyAustralia believes it is reasonable to update the interest-sensitive parameters of the weighted average cost of capital before finalising its Determination.

2 LEVEL OF COMPETITION

EnergyAustralia broadly agrees with IPART's findings on the level of competition in the NSW market.

2.1 Market definition

In its original submission, EnergyAustralia advocated the application of AEMC criteria for assessing the level of effective competition. EnergyAustralia commends IPART's approach, which is broadly in line with the criteria established by the AEMC.

EnergyAustralia concurs with the definition of the market determined by IPART, summarised below:

- Functional dimension: retail-only;
- Product dimension: electricity-only;
- Geographic dimension: NSW, metropolitan and non-metropolitan;
- Time dimension: July 2007 to June 2010; and
- Sub-markets: none apparent.

The final point above is particularly important in light of recent comments made by stakeholders at the public forum on IPART's draft Determination[1]. The assessment that there are no sub-markets was made on the preliminary results from IPART's Household Survey and should allay the fears of both the Tribunal and stakeholders that low-income households may miss out on the benefits of competition in the retail electricity market. The results demonstrate a growing maturity in the NSW market as all segments of the market are approached without any material degree of discrimination.

IPART's findings are also consistent with EnergyAustralia's own internal analysis of customers on our EnergyAssist program. We found that the proportion of customers on EnergyAssist who are also on negotiated contracts is consistent with the mix of our entire portfolio of customers. This demonstrates that vulnerable customers are enjoying the benefits of a competitive market to the same extent as all EnergyAustralia customers.

[1] http://www.ipart.nsw.gov.au/files/Transcript%20-%20Public%20Hearings%20into%20Electricity%20Retail%20Review%20-%2023%20April%202007.PDF

3 FORM OF REGULATION

EnergyAustralia supports the WAPC form of regulation proposed which represents a vast improvement from the 2004 Retail Determination in terms of the flexibility afforded to standard retailers to remove obsolete tariffs and achieve cost-reflective pricing.

Vulnerable customers are best addressed through a targeted hardship scheme which we are in the process of expanding.

We believe that some minor amendments to the pass through provisions are warranted to ensure robustness, clarity and certainty.

EnergyAustralia believes there is merit in introducing a 're-opener' provision in the Determination should the energy cost allowance not adequately allow for movements in the wholesale spot and contract market.

3.1 Weighted average price cap

EnergyAustralia fully supports the Tribunal's move to a Weighted Average Price Cap with no relevant restrictions on individual tariff movements. The decision better supports the ability for EnergyAustralia to deliver efficient pricing to all customers than the Target R framework in the current Determination. The decision to move towards a more flexible form of price control is sensible in an environment where competition has evidently matured since the 2004 Retail Determination was made and we transition to an unregulated retail environment.

3.1.1 Target tariff components

In its draft Determination, IPART recognises the problems associated with individual tariff-setting (as adopted in the 2004 Retail Determination). The more 'granular' the targets IPART attempts to set, the greater the scope for "averaging error".

While this draft Determination represents a significant step forward in regulatory price control, we believe some further refinement is warranted.

The R values

EnergyAustralia proposes that IPART remove the variable R for peak, shoulder and off peak when making its final Determination. The inclusion of these time of use rates introduces the possibility of averaging error. A more effective, and lighter-handed approach, would be to allow the standard retailers to set their regulated time of use rates to the standard R on a weighted average basis. This approach is explored in more detail in Section 6.

The N values

The weighted average price control formula holds actual network charges constant on both sides of the pricing equation, effectively allowing the full pass through of all actual network charges. This is critical to ensuring that the price deemed efficient by IPART is actually achieved.

The quantities

EnergyAustralia believes the approach to setting the quantities to be used as weights in the operation of the weighted average price cap are not unreasonable. Setting the quantities on a year-by-year basis helps mitigate the uncertainty associated with forecasting regulated load over the medium term.

3.1.2 Tariff constraints

EnergyAustralia is in the process of expanding its hardship program (EnergyAssist) in consultation with consumer advocacy groups and with reference to recent legislative changes in Victoria. We believe a targeted approach to addressing the needs of vulnerable and low income customers is more efficient than alternative measures such as bill constraints which are blunt instruments that poorly protect those to whom it is intended.

The details of our proposed hardship program can be found in Appendix A but are summarised below. Essentially, the initiatives to be implemented in the roll-out of an expanded hardship program fall into four main areas that address the various stages of customer involvement in the EnergyAssist program:

1. SELF IDENTIFY. Customers must be in a position to identify as being in hardship. EnergyAustralia's contact centre will receive empathy and sensitivity training, training on low-level assistance programs and advocate the use of CentrePay where appropriate

2. AWARENESS OF ENERGYASSIST. EnergyAustralia will improve customer awareness of the EnergyAssist program through mail notification and additional website content. This information will be made available in a variety of languages for culturally and linguistically diverse (CALD) customers.

3. REDUCE BILLS THROUGH EFFICIENCY. All customers (including vulnerable customers) should be informed about energy, energy consumption and energy conservation. Without this understanding customers' behaviour cannot change. Energy 'literacy' for vulnerable customers is particularly important and serves a genuine opportunity to reduce their energy bills.

4. FINANCIAL ASSISTANCE. Expanding the case management tools (such as introducing 'no fixed fee' tariff and payment matching) to target key financial obstacles should better place the EnergyAssist team to help customers and shorten the time these customers spend on our hardship program.

3.2 Cost pass through

EnergyAustralia supported the introduction of a pass through mechanism in its submission to IPART's Issues Paper. The pass through provisions we proposed were intended to apply to exogenous, unforeseen events which impose material costs on the standard retailers, similar to that in place for the network business. We believe this is consistent with the objective of the Terms of Reference: to achieve full cost-reflectivity by the end of the Determination period, by ensuring that all costs now and into the future are adequately accounted.

EnergyAustralia believes that a cost pass through mechanism needs to:

- provide a clear definition of eligible costs;
- minimise administrative costs;
- balance the interests of customers and retailers in terms of incentives for efficiency (it should not undermine incentive to minimise costs); and
- allow the change in costs to be readily distinguished from costs already incorporated.

We believe the pass through mechanism included in IPART's draft Determination largely maintains these characteristics. However, we propose some minor amendments in order to ensure a robust framework for passing through costs is achieved:

3.2.1 The materiality threshold

The materiality threshold in the draft Determination is set at an amount that exceeds 0.25 per cent of the standard retail supplier's revenue from the previous year (clause 15.1(c)). However, revenue is not defined. It is not clear whether "revenue" relates to moneys earned from the 'R' component of regulated retail prices only, or the complete ('N+R') price.

For certainty, EnergyAustralia submits that IPART clarify the definition of revenue in its final Determination.

3.2.2 Period of commencement

EnergyAustralia considers that an amendment is necessary to the draft Determination to capture pass through events that may occur on or after the making of the final Determination but before 1 July 2007. In the draft Determination, the definition of "regulatory change event" is limited to decisions made by any authority, the coming into operation of an applicable law or the coming into operating of an amendment to or revocation of an applicable law, on or after 1 July 2007. To ensure that regulatory change events that occur after the making of the final Determination are captured, the following amendment could be made to the definition:

> ***regulatory change event*** means:
>
> (a) a decision made by any *authority*;
>
> (b) the coming into operation of an *applicable law*; or
>
> (c) the coming into operation of an amendment to or revocation of an applicable law,
>
> on or after the making of this determination ~~1 July 2007~~ that:
>
> (d) has the effect of substantially varying:…

3.2.3 Timing of IPART's decision

The draft Determination allows the Tribunal to delay the decision on a pass through amount for one or more years (clauses 15.3(c) and 15.4(c)). EnergyAustralia believes the flexibility granted to the Tribunal is unnecessary and inappropriate, particularly given the relatively short length of the Determination period. It gives rise to unnecessary regulatory uncertainty.

EnergyAustralia proposes an alternative which has regulatory precedent and improves certainty; an approach similar to that in the National Electricity Rules and the IPART Distribution Determination. The process for the approval of a positive pass through amount as set out in clause 6A.7.3 of the National Electricity Rules is as follows:

(a) the Transmission Network Service Provider must submit to the Australian Energy Regulator (AER), within 90 business days of the relevant positive change event occurring a written statement detailing, amongst other things: the details of the positive change event; the eligible pass through amount in respect of that event; the positive pass through amount the provider proposes in relation to the positive change event; the amount of the positive pass through amount that the provider proposes should be passed through to Transmission Network Users in each regulatory year during the regulatory control period; and evidence of the actual and likely increase in costs and that such costs occur solely as a consequence of the positive change event;

(b) if the AER determines that a positive change event has occurred the AER must determine the approved pass through amount and the amount of that approved pass through amount that should be passed through to Transmission Network Users in each regulatory year during each regulatory control period;

(c) if the AER does not make the determinations referred to in (b) above within 60 business days from the date it receives the Transmission Network Service Provider's statement and evidence, then, on the expiry of that period, the AER is taken to have determined that:

(d) the positive pass through amount as proposed in the provider's statement under paragraph (a) above is the approved pass through amount in respect of that positive change event and;

(e) the amount of that positive pass through amount that the provider proposes in its statement under paragraph (a) above should be passed through to Transmission Network Users in each regulatory year during the regulatory control period, is the amount that should be so passed through in each such regulatory year.

3.3 Proposed re-opener for energy costs

Both the wholesale electricity spot and contract market have increased substantially since Frontier Economics' final report on energy cost allowances. Should IPART choose not to uplift the energy cost allowance to capture the level needed to underpin generation investment, EnergyAustralia's preferred alternative is an energy cost event re-opener. The proposed re-opener would work in the following manner:

- ***Trigger***. A forward-looking reference point should be used by IPART to trigger a review of the energy cost allowance. A good example would be a market-based trading screen such as the AFMA forward curve. (It is important though that the AFMA curve itself is not used directly to set the energy cost allowance as such mechanisms are subject to influence.)
- ***Review***. IPART would engage independent expert consultants to re-assess the energy cost allowance.
- ***Cap / collar.*** EnergyAustralia appreciates the reasonableness and transparency of IPART's draft Determination to recognise and include a volatility premium and increased margin to compensate for moving into a riskier, non-ETEF environment. We propose a trigger in movement of ± 20% of the energy cost allowance such that it only applies in extremely exceptional circumstances. At this wide range of movement, a change to the margin and volatility allowance would be unwarranted. The base reference for a ± 20% trigger point would be the contract market prices assumed by Frontier Economics' in its final cost allowance recommendation should this be adopted by the Tribunal. The inference of this window of ± 20% is that the volatility allowance should capture and allow for movements up to this level (but no more).

Importantly, the re-opener differs from a specific pass through mechanism as it is intended only to apply in exceptional circumstances.

An alternative re-opener mechanism is a retrospective true-up, where the actual purchase costs of the standard retailers for a given year flow into the price setting process of the subsequent year. This would have the benefit of not requiring any subjectivity in the forecasting process. Concerns over the apparent diminished incentive to run an efficiently-hedged portfolio are unfounded because the standard retailer must keep their purchase costs efficient otherwise it will simply open up headroom under the tariff.

4 ENERGY COST ALLOWANCE

Movements in the wholesale energy costs since IPART began their review far exceed the allowances in Frontier Economics' modelling. While the modelling was consistent with the observed market history at the time it did not adequately reflect the risks and consequently must be reviewed.

The volatility premium assessed by Frontier Economics' significantly understates the cost and risk associated with transacting electricity in the NEM by at least 80%.

The declining real price of electricity proposed by Frontier Economics' is inconsistent with other aspects of their modelling and must be amended to reflect an appropriate risk management premium.

4.1 Recent movements in forward contract prices

In the last 12 months NSW flat forward contract prices have risen from around $37-39/MWh across the curve to over $80/MWh (2007-08), $50/MWh (2008-09) and $45/MWh (2009-10).

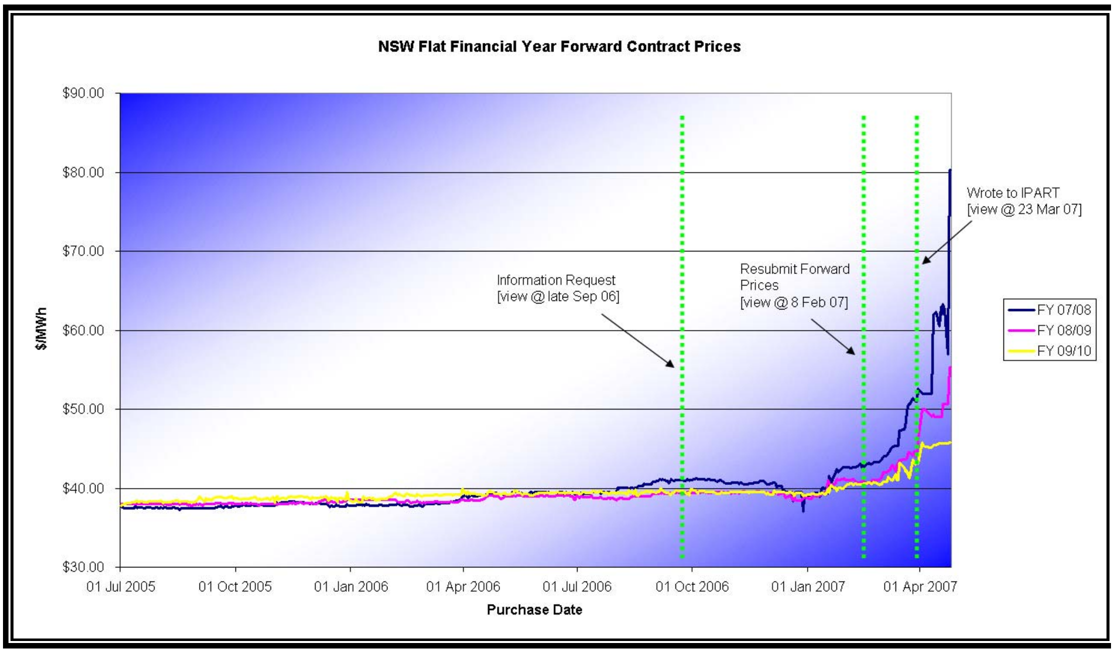

Figure 1 - Time Series of Forward Contract Prices (NSW Flat Contracts)

The first $5/MWh of this movement reflects organic supply demand tightening that had not previously been priced in. The remainder of the movement (up to $35/MWh in 2007-08) reflects a water scarcity premium, resulting from the mothballing of 1,100MW of Queensland base load capacity for at least the next 12 months and water shortages in the Snowy Hydro scheme, Hydro Tasmania's dams and the Thomson Dam in Victoria.

Without improvement in water conditions we should expect upward pressure to remain on wholesale prices (contracts and spot) until new (un-water-constrained) capacity comes on-line. While Kogan Creek will ostensibly offset up to 800MW of this deficit, annual load growth will consume a significant portion of this. Therefore the construction of further capacity is required to overcome the current developments in the wholesale markets. Furthermore, the duration of this upward pressure will be a function of the lead-time to establish new capacity once threshold prices are achieved.

AFMA Median NSW Flat Contract Prices at…	07-08	08-09	09-10
26 September 2006 (basis of IR)	$41.00	$39.40	$39.14
24 January 2007 (basis of re-submissions)	$42.45	$41.09	$39.59
% Increase from IR	4%	4%	1%
24 April 2007 (market at time of writing)	$80.30	$55.25	$45.75
% Increase from IR	96%	40%	17%

Table 1 - Changing AFMA Median NSW Flat Contract Prices

The market has moved 96%, 40% and 17% for the three financial years of the determination respectively, since the Information Request was submitted. The potential for this movement should have been reflected in the volatility allowance; however it too was significantly understated. Consequently the hedge costs analysis must be revisited in light of these market developments.

4.2 The energy cost allowance and investment

Investment in new capacity will be a function of the energy cost allowance in this price Determination. Therefore the energy cost allowance must be sufficient to encourage new investment, otherwise energy purchase costs will remain well above LRMC well beyond the term of this Determination.

While it is not possible to observe a price in the market that directly reflects the allowance being determined by IPART, one can observe its side effects. If the energy cost is set too low, investment will be hindered and existing suppliers will retain market dominance and the ability to extract super-normal profits in the absence of new base-load investment. In this case observable contract and spot prices will remain much higher than IPART's energy cost allowance and competition will be stifled because the cost of hedging will be well above the energy cost allowance within the tariff.

Alternatively, if the energy cost allowance is set too high, investment will come swiftly, underwritten by contracts reflecting the energy cost allowance. As new capacity comes on line spot prices will slump as will the ensuing contract market.

Importantly though, any new generation investment will have been made on the basis of contracts written in the higher market environment; a similar phenomenon as currently observed in the REC market. Consequently, IPART have the challenge to set the price at a level that enables efficient investment.

Figure 2 highlights how the shape of the forward curve has changed over time and the magnitude of recent increases. Prior to July 2006 the curve generally moved in relatively small increments had been largely inclining. This trend of backwardation[2] strengthens approaching April 2007. We can see that FY09/10 flat prices seem to have stabilised around $46/MWh, while the near end of curve shows sellers continuing to extract super-normal profits. The FY09/10 price is a reasonable indication of the price at which the market expects base-load investment to occur and allows some lead time to build the plant, although even this is arguably optimistic. While this level would appear to be above the expectation of Frontier Economics, we must consider the risk that the future cost of carbon brings to a coal-fired base-load investor. These investors must now take a 30 year view on carbon costs. While this risk is generally a positive influence for investment in peaking generation which emit less carbon than base-load plant, the risk is all downside for a coal fired investment. Therefore it would appear that a base of around $47/MWh (flat) would be an appropriate level.

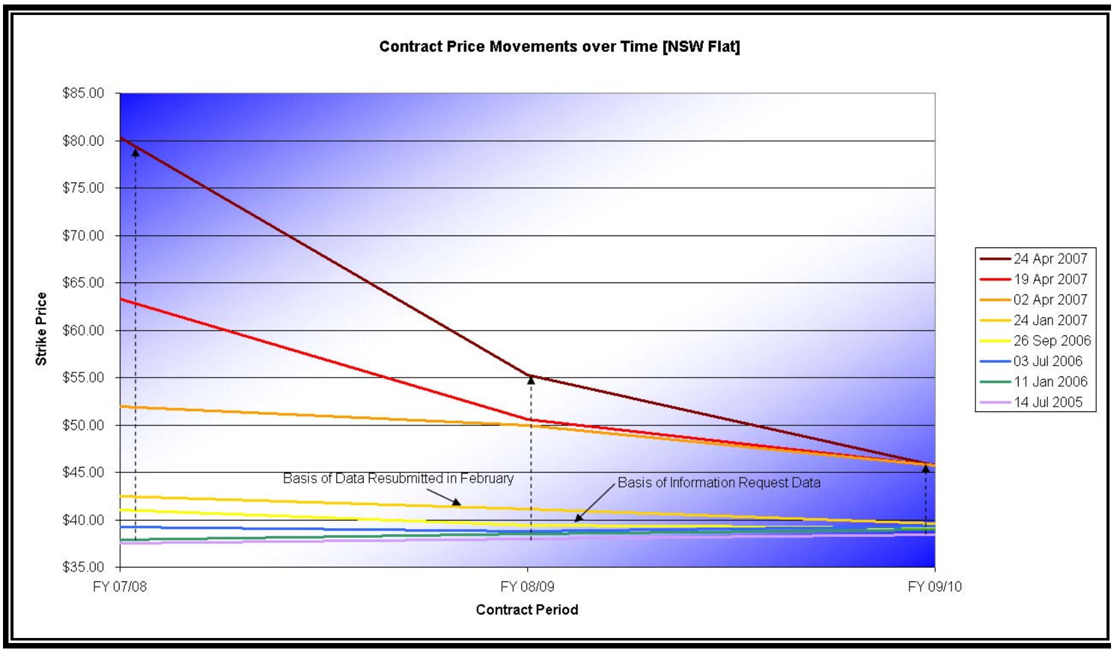

Figure 2 - Movements in Forward Contract Prices (NSW Flat Contracts)

[2] "The theory that says futures prices will tend to rise over the life of a contract, therefore the near-term contracts trade at a higher price than the longer-term contracts." American Psychological Association (APA): backwardation. (n.d). *Investopedia.com.* Retrieved May 01, 2007, from Dictionary.com website: http://dictionary.reference.com/browse/backwardation

4.3 Recent changes in the spot markets

The first 10 years of the NSW spot market has been dominated by prices below $30/MWh combined with intermittent spikes of up to of $10,000/MWh. While these spikes occurred less than 1% of the time, they have been responsible for approximately 25%-35% of the spot market value. This has allowed hedge portfolios with significant cap and spot exposures to perform well and similarly encouraged investment in peaking generation.

However since late March 2007, a step change in the dynamics of spot prices has accompanied contract market movements. Spot prices now routinely liquidate in the $50/MWh-$150/MWh range, significantly increasing the average spot price but with relatively low volatility. This environment renders $100/MWh and $300/MWh caps worthless. By way of example, Figure 3 contrasts the spot market prices for the period February–April between 2006 and 2007. The horizontal axis represents spot price volatility and the vertical axis indicates average spot price. Prior to 2007, high spot prices were characterised by high volatility. This is exemplified in the results of February 2006, while prices in March and April 2006 had very low volatility and consequently low averages. However in 2007 we can see that volatility is substantially reduced yet average prices are much higher than previously. The February-April summaries highlight the change. In 2006 the average price through this period was $36.59/MWh and has increased to $56.22/MWh in 2007 (a 54% increase), while at the same time the standard deviation has fallen from $347/MWh to $73/MWh (an 80% reduction).

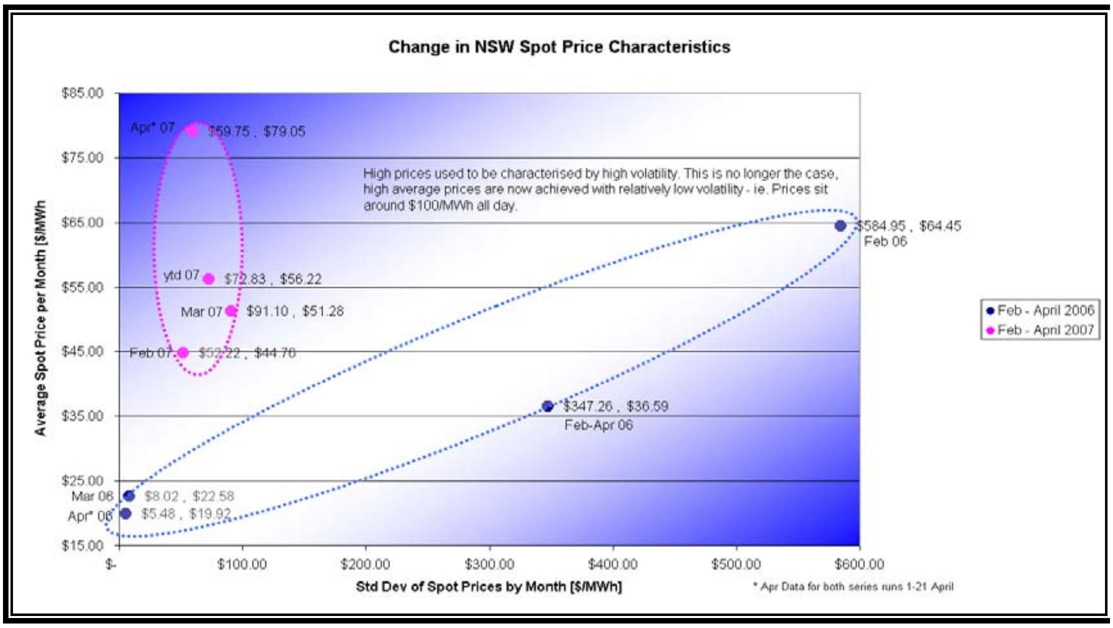

Figure 3 - Volatility Changes in the Spot Markets

Due to the extreme and significant risks in the wholesale energy purchase costs, the strength and purpose of hedging it is not simply to return, by chance, a cheap wholesale cost, but to stabilise wholesale cost outcomes across a broad range of potential scenarios. Given that the portfolios resulting from Frontier Economics' modelling contained substantial cap and spot exposures, they are extremely expensive in today's spot environment. This further underpins the argument that Frontier Economics' 'optimal' portfolios were not robust, but rather were optimised for a specific range of spot outcomes reflective of the first ten years of spot price history and so significantly understate the cost and risk of energy purchases.

4.4 Volatility Premium

The concept of the volatility premium based on an assessment of the working capital required to fund an 'extreme' event is an appropriate proxy to assess residual uncertainty in the energy price. However, the assumptions regarding the magnitude and frequency of these events which underpin Frontier Economics' results are inconsistent with observed market behaviour.

Firstly, Frontier Economics have implicitly assumed that the magnitude of these occurrences reflects an impost of around $10/MWh (3.5 standard deviations[3]), representing an 18% premium to the expected cost for EnergyAustralia's regulated load. Simplistically, the working capital cost of holding these funds in reserve at 8.6% is $0.86/MWh. However the movements we have observed in both the spot and the contract market in the last 12 months represent increases in the contract market ranging from over 100% for 2007-08 to 25% for 2009-10. Further, NSW spot prices in April 2007 have liquidated some 350% above the historical April average and 250% above the previous maximum. While it is difficult to predict the precise value of possible market movement, it is clear that the potential for price increases well in excess of the 18% foreshadowed in Frontier's analysis are entirely plausible.

While the recent price events have not previously occurred, the risk of these events occurring has always been inherent in the design of the NEM. The physical necessity of electricity markets to balance supply and demand in real-time combined with the fact that electricity is not readily substituted in the near term, affords suppliers significant market power at times of tight supply / demand balance. While it may require supply / demand conditions to be suitable, once these conditions exist suppliers can wield enormous market power for sustained periods of time.

Secondly, the frequency or likelihood of the event has been assessed by Frontier Economics as 1 in 200 years, or 0.5%. However, the conditions present in the market today are consistent with the particular stage of the investment cycle we find ourselves in [see Figure 4, Item (3)]. The preceding spot price characteristics [Item (2)] have encouraged investment in peaking plant to capitalise on a small number of high-priced events. As the proportion peaking capacity increases and demand grows,

[3] Frontier Economics, *Energy Costs, Public Report*, March 2007. pp36-38 s5.4

the peaking capacity will be used more frequently, eventually reaching the point where it routinely setts the marginal price (which is what we are observing today). This can occur either because it is truly the marginal plant or opportunistic base-load suppliers may achieve the equivalent outcome through their bidding strategies, forcing the peaking plant into the marginal position. Therefore these current market conditions are not entirely surprising, although the market has been caught off-guard by the extent to which the water scarcity has accelerated this part of the cycle.

Today's level of wholesale price will undoubtedly attract the attention of new base load investment if retailers and customers can afford to pay it. However the lead times are substantial (compared to those for gas fired peaking generation) and the equation is further complicated by the future cost of carbon as discussed in 4.2. Therefore this current price scenario is a function of the stage of the investment cycle the market is in and therefore this 'extreme' event is likely to be as frequent as the cycle itself. All other things being equal this cycle could reasonably be assessed in the order of 15-25 years.

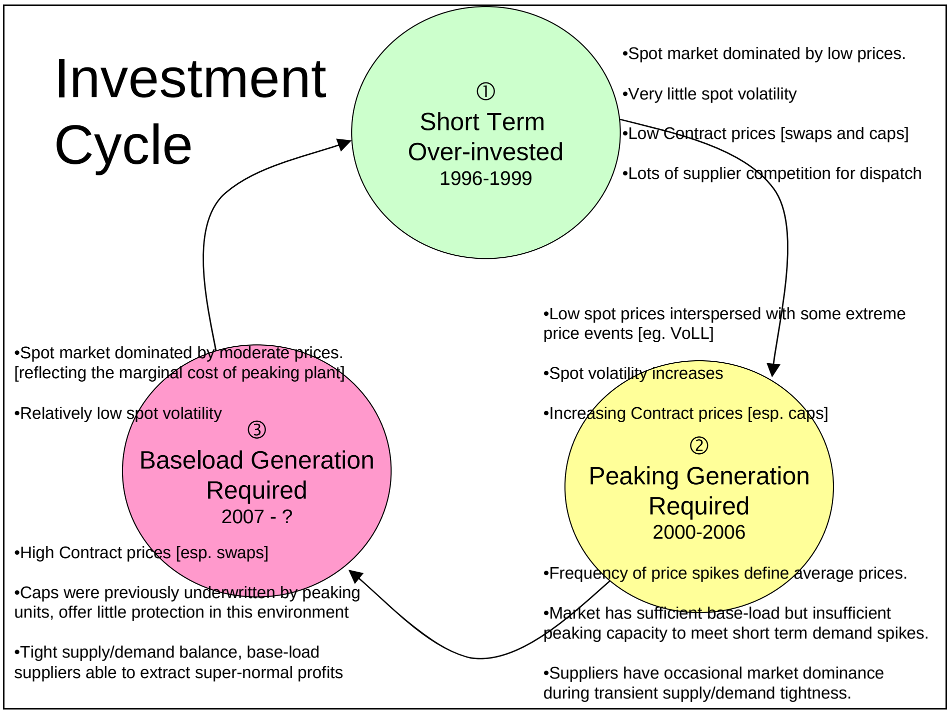

Figure 4 - NEM Investment Cycle Characteristics

For the purpose of illustration we will assume that this cycle repeats every 20 years and so today's prices are likely to occur 5% of the time (cf. 0.5%) and is likely to reflect an increase of at least 100% (cf 18%). Frontier Economics have further stated that this risk can be completely hedged away for an additional $9/MWh premium, or alternatively the retailer should carry sufficient cash reserves to fund this 1 in 20 year event. At a base price of $55/MWh a 100% increase in costs represents an additional $55/MWh – the cost of retaining these funds at 8.6% is approximately $4.70/MWh (which is cheaper than the proposed $9/MWh premium) in which case it makes sense to self-insure. Alternatively if the magnitude of this event represents a 200% increase, then the working capital requirements would be $9.40/MWh in which case it would be marginally more efficient to buy the $9/MWh hedge. In short this methodology is extremely sensitive to the assumed frequency and magnitude of the 'extreme' events. But there is sufficient empirical evidence to suggest that Frontier Economics' estimates are understated by at least 80% and likely much more.

4.5 Linking forward prices and hedging costs

Retailers hedge in order to reduce the price uncertainty of energy purchases in the spot market. For the purpose of hedging it is essential that a retailer balance their hedge and physical portfolios, as a hedge portfolio in isolation can be just as risky as the spot prices they are designed insulate against. Accordingly, a retailer will tend to buy hedge volumes to match customer sales. For mass market customers a retailer would typically build up the hedge portfolio for a given period over 3 years, acquiring approximately one third of its hedge book each year.

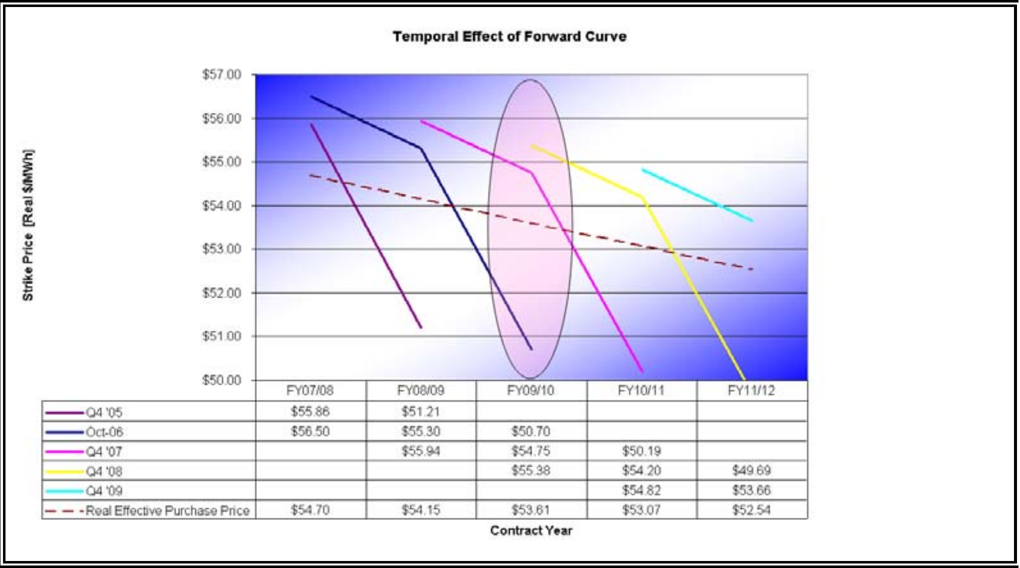

Figure 5 - Temporal Movement of forward prices

Figure 5 illustrates the general movement of the forward curve over time, all other things being equal. Since 2000, NSW energy prices have been moving at around CPI-1%[4]. The prices underpinning Figure 5 are the energy purchase costs proposed in the draft Determination for EnergyAustralia's regulated load[5]. This forward-curve has been extrapolated to reflect the transition of the forward curve over time.

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[4] McLennan Magasanik Associates, *Allowance for Wholesale Costs in Retail Tariffs July 2007 to June 2010*, Final Report 21 December 2006, p15.

[5] Independent Pricing and Regulatory Tribunal, *Promoting Retail Competition and Investment in the NSW Electricity Industry: Regulated Electricity Retail Tariffs and Charges for Small Customers 2007 to 2010 – Electricity – Draft report and Draft Determination,* April 2007, Table 6.7 p59.

The resultant cost of hedging a given period is the average of the prices that applied in each of the three years when the cover was purchased. The shaded area in Figure 5 shows the relevant prices applicable to hedging 2009-10. The hedge portfolio pertaining to 2009-10 will therefore be the average of $50.70/MWh, $54.75/MWh and $55.38/MWh, yielding $53.61/MWh (real 06-07$). Based on this analysis the effective hedging costs are shown in line b) of Table 2.

Year	07-08	08-09	09-10
a) Frontier Curve (Real 06-07$)	$56.50	$55.30	$50.70
b) Effective Hedge Cost (Real 06-07$)	$54.70	$54.15	$53.61

Table 2 - Effective Cost of Hedging

4.6 Risk premium absent in third year

EnergyAustralia maintain that LRMC is not the appropriate basis for setting the energy cost allowance. However, it does serve as a useful reference. Frontier Economics' LRMC results[6] (Table 3, line a)) show a marginal real increase across the three years from $49.90/MWh to $50.20/MWh, while line b) shows the conservative market-based energy costs of $55.60/MWh, $55.30/MWh and $50.70/MWh adopted by the Tribunal for EnergyAustralia's regulated load shape. In the first two years there appears to be a hedge premium in excess of $5/MWh, however in the third year the premium has almost vanished. The third year result appears to be inconsistent with the first two years and consequently this premium is virtually absent from the resulting energy price allowance recognised in the draft Determination which targets the third year result only.

Year	07-08	08-09	09-10
a) Frontier LRMC (Real $06-07)	$49.90	$50.10	$50.20
b) Frontier Curve Real (Real $06-07)	$56.50	$55.30	$50.70
Implied Hedge Premium (Real $06-07)	$ 6.60	$ 5.20	$ 0.50

Table 3 - Implied Hedge Premium

EnergyAustralia believe the absence of the hedge premium in the third year and consequently in the draft Determination is incorrect and should be consistent with the 2007-08 and 2008-09 analysis.

[6] Independent Pricing and Regulatory Tribunal, *Promoting Retail Competition and Investment in the NSW Electricity Industry: Regulated Electricity Retail Tariffs and Charges for Small Customers 2007 to 2010 – Electricity – Draft report and Draft Determination,* April 2007, Table 6.3 p52.

4.7 Implications of Transition Path

The Tribunal has chosen to transition towards the 2009-10 energy costs, effectively overlooking the costs assessed in the preceding two years[7]. This decision has been justified on the basis that competition will increase over the term of the Determination and that the ETEF progressively disappears over this time. The Tribunal reason that because of this transition standard retailers are not fully exposed to the market risks that have been ostensibly allowed for in IPART's cost assessment.

Year	07-08	08-09	09-10
a) Hypothetical EA Single Rate $/MWh8 Draft Determination, Table 8.2 p79	$78.70	$78.00	$73.40
b) Equivalent Energy Cost Allowance $/MWh Draft Determination, Table 6.7 p59	$56.50	$55.30	$50.70
c) Hypothetical Single Rate $/MWh Draft Determination, Table 8.3 p81	$67.10	$70.10	$73.40
d) Implied Energy Cost Allowance Assessed by EnergyAustralia	$48.20	$50.00	$50.70

Table 4 - Implied Energy Cost Allowance

While we agree that the ETEF is rolling off, we believe the level of competition allowed for in this draft Determination[9] already exists. Therefore, any shortfall resulting from this transition path must be reflected in an implied energy cost with consequential impacts on competition. The Tribunal must be cognisant of the impact of setting a tariff that implies an energy purchase cost allowance below market as this will stifle competition.

4.8 CPI Escalation

In response to IPART's Information Request, EnergyAustralia provided a series of price forecasts in October 2007. These were provided in nominal terms consistent with the normal operation of the market. For the purposes of their analysis, Frontier Economics represented these price forecasts in real dollars. Table 5 compares the forward curves provided by EnergyAustralia [in nominal terms, line a)] to their representation in Frontier Economics' report[10] [b)]. Line c) indicates that the ratio of real to nominal prices and line d) highlights the year-on-year change in this ratio. The

[7] In practical terms it is only the energy cost that varies over the 3 years in real terms.

[8] Note that only the single rate for EnergyAustralia regulated load shape is shown in Table 4, however all of the associated variable rates in the draft Determination (such as Peak, Shoulder, Off Peak/Controlled Load A and Controlled Load B) require similar adjustment.

[9] Based on the recognised retention period of 6 yrs for business customers [17% pa] and 8 years residential customers [12.5%pa].

[10] Frontier Economics, *Energy Costs, Public Report*, December 2006. p25 Figure 8

observed year-on-year changes are shown in green indicating a 3.1% p.a. allowance for inflation. This trend has been extrapolated back to Q3 2007 (orange) and the ratios in line c) calculated from here.

These results imply that the reference year for the Frontier Economics analysis is not financial year 2006-07 as stated in their report, but calendar year 2006. The implication of this is that all prices must be uplifted a further 1.5% (half the assumed inflation rate) to express them in 2006-07$.

	Cal 06		Cal 07				Cal 08				Cal 09				Cal 10	
	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
a) EnergyAustralia provided Forward Prices [nominal]					54.44	62.32	96.72	45.06	55.36	60.26	98.65	45.96	56.47	61.46	100.62	46.88
b) Frontier Economics' presentation of Forward Prices [real]					52.70	60.40	90.80	42.30	52.00	56.60	89.80	41.80	51.40	55.90	88.70	41.30
c) Ratio of Real to Nominal Prices	100 %	100%	97%	97%	97%	97%	94%	94%	94%	94%	91%	91%	91%	91%	88%	88%
d) YoY Change	-	-	-	-	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
e) Average Calendar Year Factor	100%		97%				94%				91%				88%	
	06/07				07-08				08-09				09-10			
f) Average Financial Year Factor	98.5%				95.5%				92.4%				89.6%			

Table 5 - Implied CPI Escalation

4.9 NEMMCO Fees

In its draft Report, the Tribunal states that it is unaware of any information that would cause it to disagree with Frontier Economics' recommendation. EnergyAustralia would like to bring to the attention of the Tribunal the release of NEMMCO's draft Statement of Corporate Intent for 2007-08. In this draft SCI, NEMMCO outlined a 4.6% increase in its budgeted fee revenue for 2007-08. NEMMCO identified the "tighter market demand for skilled staff in the industry"[11] as one of the key reasons for the increase in budgeted fee revenue.

This reality is in marked contrast to the position held by Frontier Economics in its final report, based on NEMMCO's SCI for 2006-07. Here it was held that general participant fees would remain constant in real terms. The updated draft, however, reveals the realities of today's labour market. It is apparent that skilled staff are in short supply, driving increases in wages beyond the general level of inflation.

[11] NEMMCO, *2007/2008 Statement of Corporate Intent, Draft,* 17 April 2007, p 5

EnergyAustralia submits that the NEMMCO fee allowance be revised upward in light of NEMMCO's draft SCI for 2007-08.

5 RETAIL COST AND MARGIN ALLOWANCE

EnergyAustralia is satisfied that the net margin allowance in the Tribunal's draft Decision delivers an appropriate return to the standard retailers as we transition towards no retail price regulation.

The Tribunal should err on the lower end of the retained customer lives recommended by Frontier Economics, confident that proposed increases in regulated prices in this draft Determination should increase competitive pressure and in turn churn rates (provided energy costs are adequately captured).

Wage increases will far outweigh any perceived labour productivity improvements in the foreseeable future and this should be factored into the retail cost allowance.

5.1 Retail operating costs

In our response to Frontier Economics' draft Report, EnergyAustralia submitted that there were economies of scope associated with the stapling of a retail / distribution business that would not be accessible to a MMNE retailer. The Tribunal appreciated these synergies and for this reason erred towards the higher end of the range estimate recommended by Frontier Economics.

EnergyAustralia submits that there is justifiable reason for the Tribunal to set the allowance for operating costs at the highest ($80 per customer) end of Frontier Economics' recommended range. We base this argument on some limitations in Frontier Economics' final report and detail these below:

5.1.1 Labour productivity gains

We understand from IPART's draft Determination that consideration is being given to productivity gains and the potential effect on its forward view of operating costs. EnergyAustralia re-emphasises the position held in its response to Frontier Economics' draft Report: productivity gains (such as those achieved through outsourcing) have been largely exhausted since the commencement of FRC.

Frontier Economics' refer to a report by Access Economics which suggests that labour productivity for the utilities sector is expected to rise moving forward. It is unfortunate that Frontier have introduced new material into their final report and given this information a fair degree of weighting in developing their final recommendation, when this new material has not been subject to any scrutiny in its application here. It would also be unfortunate if IPART gave the Access Economics findings any credence in applying to a MMNE retailer.

The context of Access Economics' assessment was for the operating and maintenance costs of an electricity transmission company in Queensland. In measuring productivity, reference was made to output per hour worked. In turn, output was assessed as annual peak MW per hour worked, annual MWh per hour worked and annual revenue per hour worked. A report by NERA[12] for TransGrid highlighted the inappropriateness of the output measures for an electricity transmission business whose work involves the "maintenance of the network assets to an acceptable level of reliability."[13]. EnergyAustralia submits that the Access Economics' productivity assessment is *even further* removed for a MMNE retailer whose primary labour-based costs are related to business functions such as contact centre operations. To deduce that overall labour costs will fall for a MMNE retailer based on the Access Economics' findings would be of some concern to EnergyAustralia.

EnergyAustralia therefore submits that the Tribunal give no weighting to Frontier Economics' assertion, based on the irrelevance of Access Economics' findings established above.

5.1.2 Wage increases

Moving forward, the biggest challenge for a MMNE retailer relating to retail costs is containing these costs in the face of ever-increasing wage pressure. EnergyAustralia expects labour costs will continue to rise in excess of the inflation rate. This is supported by the forecast work performed by BIS Shrapnel which suggests that for the next three financial years, the Wage Cost Index is expected to increase by between 4.6% and 5.7% p.a[14]. EnergyAustralia is particularly exposed to increases in labour-related costs as these represent a large proportion of our (and mass market retailers') cost to serve.

As we have noted in Section 4, NEMMCO has budgeted for an increase in fee revenue incorporating a marked increase in labour costs against previous years. This reflects the "tighter market demand for skilled staff in the industry."[15]

5.1.3 Ofgem report

EnergyAustralia maintains that the Ofgem average range produced in Frontier Economics' draft report, and included in their final report, is understated. We firmly believe that some adjustment to the original benchmarked operating costs provided

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[12] NERA consulting, *Review of Access Economics Report, TransGrid*, 8 February 2007.

[13] Ibid, p. 9

[14] BIS Shrapnel, *Economic Outlook*, January 2007, p. 2.

[15] NEMMCO, *2007/2008 Statement of Corporate Intent, Draft,* 17 April 2007, p 5.

by the PESs is warranted to achieve a better like-for-like comparison necessary for robust benchmarking.

The adjustments performed by Ofgem occurred at a time when there was a proposal for separation. Ofgem sought to make discrete adjustments to opex to reflect the true separation of functions between the distribution businesses and the supply (retail) businesses.

EnergyAustralia agrees that, when assessing those costs identified by Ofgem to be transferred from the distribution business to the retail business, it is important to only assess those movements that are relevant to the NSW market for a MMNE retailer. Indeed, analysing operating costs at this more granular level quickly reveals the difficulty with benchmarking across jurisdictions. Notwithstanding, should we remove those transfer elements Frontier Economics' have expressly identified as rendering the comparison "less relevant"; that is:

- Transferred costs associated with billing;
- Transferred costs associated with metering;
- Business separation costs;
- Data management services; and
- Lost customer costs.

the residual costs - advertising and marketing, customer services, corporate and 'other' – should remain legitimate costs to be included. Indeed, in their absence, a like-for-like comparison would not be achieved. We have replicated the analysis below, using the information in Ofgem's final proposal for the supply and distribution businesses:

Table 6 - Adjusted opex for Ofgem PESs

	<100kW 1st tier supply business costs	**Transfer from Dist'n To Supply**	**Adjuster business supply cost**	**£ / customer**	**$ / customer**
	(98-99)£M	**(98-99)£M**	**(98-99)£M**	**(06-07)£**	**(06-07)$**
Eastern	63.3	+21.7	85.0	31.0	**104**
East Midlands	51.6	+11.6	63.2	32.8	108
London	53.5	+32.0	85.5	37.0	109
Manweb	26.1	+13.4	39.5	34.9	110
Midlands	64.8	+4.0	68.8	33.6	125
Northern	43.8	+8.0	51.8	32.7	117
NORWEB	63.2	+11.9	75.1	35.2	113
SEEBOARD	47.9	+18.9	66.8	38.6	110
Southern	56.9	+5.8	62.7	36.5	119
SWALEC	24.9	+8.5	33.4	32.3	130
South Western	27.1	+4.8	31.9	31.8	123
Yorkshire	59.1	+10.1	69.2	52.5	109
ScottishPower	45.9	+11.2	57.1	31.0	107
Hydro-Electric	50.8	+4.6	55.4	32.2	**177**
Total	**678.9**	**166.6**	**845.5**	**34.3**	**115**

The adjusted benchmark range is \$104 to \$177, with a weighted average of \$115. For transparency, the complete adjustment table along with references is provided in Appendix B.

5.2 Retail acquisition costs

EnergyAustralia believes that the inclusion of customer acquisition costs (CAC) in the calculation of retail costs is consistent with the Minister's Terms of Reference which seeks to include all costs associated with a MMNE retailer. As a new entrant, it is necessary for the retailer to invest in winning a customer's electricity account. In reality, an incumbent also faces similar costs as it attempts to retain its customer base. Any suggestion that customer acquisition costs are not required to be included in operating cost allowances is in marked conflict with the Minister's Terms of Reference.

EnergyAustralia supports the adoption of \$200 as the assumed cost of acquiring a customer. We accepted this amount as fair and reasonable in our submission on Frontier Economics' draft report. We also noted that the CAC allowance is sensitive to customer retention / churn assumptions which in turn reflect the level of competition in the market. As a result, we sought consistency between IPART's forward expectations of competition and the annualised value of CAC allowed.

EnergyAustralia maintains that, all other things being equal, an increase in the regulated retail price will increase competition and in turn increase the level of churn. We accept that the market will not reach the level of competitive activity evident in Victoria and South Australia, for reasons unique to these jurisdictions and highlighted on page 72 of the draft Determination, but believe that it would not be unreasonable for the Tribunal to opt for the lower end of the life estimates recommended by Frontier Economics. The yearly review of Energy Market Competitiveness performed by Vaasaemg demonstrates an increasingly competitive electricity market in NSW[16]. The mooted increases in this draft Determination should only serve to further increase this level of competitiveness and in turn churn activity.

5.3 Retail margin

In this transitive phase towards no retail price regulation, EnergyAustralia believes that an allowance of 5% for retail margin is appropriate where non-systematic energy purchase risks are captured elsewhere. It has been arrived at as the mid range

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[16] Peace Vaasaemg, *World Retail Energy Market Rankings*, June 2005, p. 5. NSW is ranked 10
Peace Vaasaemg, *World Retail Energy Market Rankings*, June 2006, p. 5. NSW is ranked 9

estimate of the ‘three-pronged’ approach adopted by Frontier Economics in calculating retail margin, including the use of the expected returns approach.

To the extent that the expected returns approach has captured systematic risks EnergyAustralia are satisfied that this mechanism appears to deliver an appropriate return. Of far greater concern are the significant non-systematic risks that have been excluded from this process. We urge and understand that these will be considered in setting the energy cost allowance. In particular, careful attention should be paid to the volatility of the wholesale price outcome a retailer will be expected to manage. We address this point in Section 4 of our submission.

6 SETTING PRICE CONTROLS

EnergyAustralia seeks the removal of specific peak, shoulder and off peak R from the price controls, to be replaced by one, single R variable.

We believe the network charges assumed in the modelling may be understated which has an ancillary effect on the level of margin in each R value.

6.1 Time of use variable R

In developing the retail per unit costs, IPART was required to assign relevant cost allowances between fixed units (customer numbers) and variable units (consumption).The variable costs were further refined into time of use rates (peak, shoulder and off peak) and controlled load A and controlled load B. In determining the split between peak, shoulder and off peak, IPART appeared to rely on the time bands for these rates as submitted in the standard retailers' Information Requests.

EnergyAustralia believes that attempting to sub-divide the single variable rate into time of use rates is problematic for two main reasons:

1. EnergyAustralia has three different regulated time of use tariffs using two different time of use band definitions. The different definitions will affect the weighting of costs between peak, shoulder and off peak.

2. To deliver the price path sought, an assumption must be held that these time bands will remain constant for the duration of the Determination period. However, in their draft Report, IPART affords the standard retailers a degree of flexibility in setting time bands. Although EnergyAustralia has no current intention of changing time bands for regulated time of use customers, we can see that any change in these definitions will present the possibility of achieving windfall gains or losses depending on how those bands are redefined when R is expressly set for peak, shoulder and off peak.

EnergyAustralia believes there is a simple solution to overcome these concerns: remove the time of use R values completely, and direct the time of use tariff component price to the single rate R value. Integrity is maintained because the weighted average price cap relies on consumption estimates that reflect the most current time band definitions for each regulated time of use tariff. Furthermore, it better facilitates the achievement of full cost-reflectivity by removing averaging risk error. And finally, it is the approach adopted for calculating prices in this current Determination, so IPART has the surety that this approach is currently in place and working.

Should IPART continue to set the variable R at a time of use granularity, we seek that the 2006-07 starting peak rate be set appropriately. The modeling supporting this draft Determination assumes that the peak R for EnergyAustralia (6.412 cents / kWh) is the same as the standard R. This is not a fair representation because the peak R should be notionally higher than the standard R. By setting an ostensibly lower value for peak R in the first year of the smoothed price path, all but the final year peak R values are understated. Again, this highlights the problem associated with attempting to ‘granularise’ the value of variable R into peak, shoulder and off peak.

Therefore EnergyAustralia submits that, should IPART continue to set a variable peak R, the base rate for 2006-07 used in smoothing must be uplifted to reflect its higher cost.

6.2 Assumed network charges

Under the proposed WAPC form of regulation for EnergyAustralia, network charges are essentially passed through to end users. This does not mean that the expected level of these network costs can be ignored. Indeed, the assumed level of network costs used in the modelling has an important effect on the absolute level of retail margin included in each of the R values.

The model supporting the draft Determination has been released publicly. In reviewing the model it is evident that the total costs include the total actual network charges incurred by standard retailers as part of their Information Request submissions late last year. It brings this value forward by the explicit price path in the 2004 Distribution Determination plus actual general and specific pass through allowances to date, inflated for actual and expected changes in CPI.

Unfortunately, the model does not capture other network-related costs or pass through costs such as increases in transmission charges (beyond the price path assumed for the distribution businesses), the energy savings fund and the D-factor. The result is that the retail margin, determined as a percentage of total revenue (including network revenue) is understated in the R value.

EnergyAustralia submits that IPART’s price modelling is updated to reflect *all* network charges incurred by the standard retailers.

6.3 Smoothed price path

EnergyAustralia believes that a smoothed price path better manages price impacts on customers. Although there is no specific obligation on the Tribunal to mitigate price ‘shocks’ for small customers within the Minister’s Terms of Reference, it is still worthwhile to consider and appreciate the impact of any price change for customers.

It is reasonable that the Tribunal have regard for the price implications but that these should not prevent the achievement of full cost reflectivity.

EnergyAustralia advocates a price path that:

- Reaches full cost reflectivity at the end of the Determination period;
- Considers the price implications for small customers; and
- Minimises net present value (NPV) losses that accrue under the draft Determination's smoothed price path.

We believe that all objectives can be achieved by adopting a sculptured price path: that is, one in which weights a larger proportion of the expected retail price increases in the first year. Bringing forward the bulk of the overall price increase into 2007-08 reduces the extent of NPV losses and would also be propitious for customers should network prices under the next Distribution Determination period (2009-10 to 2013-14) increase significantly.

7 NON-TARIFF CHARGES

EnergyAustralia is largely satisfied with the draft Determination on non-tariff charges.

However, we continue to maintain that the late payment fee should be increased to at least $10, a level supported by industry observations and the work of our consultant, KPMG.

7.1 Security deposits

EnergyAustralia believes it is reasonable to continue relying on the provisions established in the 2004 Retail Determination in relation to the requirement for security deposits. The following sections briefly discuss our positions on key elements of this requirement.

7.1.1 Level of the deposit

EnergyAustralia agrees with the maintenance of the amount of the security deposit with reference to the average electricity account. EnergyAustralia have currently set the level of security deposits below what we are allowed, and intend to do so for the remainder of the 2007-10 Determination period.

7.1.2 Payment plan cancellation

EnergyAustralia has been an active participant in the working group established for miscellaneous charges. In this forum, a number of retailers (including ourselves) raised what we saw as a growing problem with the current Determination's rules about charging security deposits. A significant number of customers are able to avoid paying a security deposit by entering into a payment plan and then subsequently cancelling the plan.

We appreciate the additional inclusion of the requirement of a customer to provide a security deposit when a payment plan is cancelled during the first 12 months of connection. It should serve to stem the observed growing trend of avoidance.

7.1.3 Centrepay

EnergyAustralia supports the decision for CentrePay to be treated as a payment plan within the definition of the Determination. We recognise that those customers using

CentrePay are the least likely to be able to afford the upfront payment of a security deposit.

7.2 Late payment fee

EnergyAustralia does not believe that the maximum amount to be charged for late payment of $7 is sufficient to cover the costs associated with late-paying customers. There does not appear to be any robust analysis to support this level. We believe that, with the requirement to ensure all "regulated retail tariffs and regulated retail charges are at cost reflective levels…by 30 June 2010", IPART should set the late payment fee to at least $10.

7.2.1 Cost build-up approach

EnergyAustralia has sought the independent, expert advice of KPMG to assess an appropriate cost-reflective level for a late payment fee. The results of this assessment are presented in Appendix C. KPMG found, on a stand-alone, cost-reflective basis, the late payment fee should be set at between $11.71 and $11.98 in real (2005-06) terms.

KPMG assessed an appropriate level of late payment fees using a cost-build up approach, consistent with that used in its original report for EnergyAustralia on an appropriate retail opex allowance[17]. The cost build up approach is a robust way to determine a cost-reflective price by identifying all cost drivers associated with late-paying customers. These costs include:

- issuing a reminder notice;
- issuing a disconnection warning
- telephone calls to customers;
- field visits to customers; and
- working capital cost associated with overdue amounts.

In its draft Determination, IPART recognised the possibility of double-counting costs. For example, the working capital allowance that has been built into the late payment fee cost pool may already have been provided for in the retail operating cost allowance. EnergyAustralia concurs, but submits the effect of any adjustment to the retail operating cost allowance to remove late payment-related costs would be negligible and indeed not even visible in any range estimate provided by Frontier. KPMG found that, even when these overlapping costs are removed from the analysis, the late payment fee should be set at up to $9.10 in real (2005-06) terms.

[17] see EnergyAustralia's submission on Frontier Economic's draft Report, Appendix A.

7.2.2 Recognising effects of inflation

In the previous sections, we have noted the cost build up recommendation is expressed in real 2005-06 dollars. We have also identified that IPART is required to set both tariffs and charges at cost-reflective levels by 2010. With this in mind, we believe there is some onus on the Tribunal to recognise the effect of changes in CPI between now and 2010 and factor the expected escalation in general price levels into the late payment fee calculation. For example, if it was held that the CPI would increase by 3.1% per annum (assumed by Frontier Economics) then it would be appropriate to escalate the suggested charges by KPMG to 2010, the target year identified by the Minister for cost reflective tariffs and charges. This is performed below:

Late payment fee base	Benchmark, 2005-06$		Benchmark, 2009-10$	
	Low	High	Low	High
Total costs	**$11.71**	**$11.98**	**$13.23**	**$13.54**
Adjusted costs (no overlap with retail opex)	$8.63	$9.10	$9.75	$10.28

Table 7 – KPMG's assessment of late payment fees, uplifted for inflation to target year 2009-10

From Table 7, it is clear that the mid point of the fully cost-reflective late payment fee in target year 2009-10 is $13.39 and the adjusted late payment fee in target year 2009-10 is $10.02.

7.2.3 Low income customers

EnergyAustralia's credit policy, systems and call centre staff training are geared around strict compliance with the Determination. Those exceptional cases where it is claimed that the rules of the Determination have not been observed are treated seriously and investigated accordingly.

EnergyAustralia recognises that the imposition of a late payment fee is more acutely felt by low-income customers who have difficulty paying a number of bills. We believe the provisions in the current and draft Determination go some way to resolving this concern by expressly requiring a standard retailer to waive the late payment fee in circumstances where the customer has contacted a welfare agency or support service for assistance. Moreover, we provide our call centre staff with the discretion to waive late payment fees where this is seen fit; generally, where we are contacted by a customer who has, or will, pay late and that customer indicates that they are having difficulty paying their account.

In sum, we believe that with a mandate to ensure that all regulated tariffs and charges at set at cost-reflective levels by the end of the 2007-10 Determination period, it is incumbent on IPART to increase the late payment fee to at least $10. We believe there is a weight of evidence to support this level of fee as being cost-reflective that cannot be ignored.

7.3 Dishonoured cheque fee

EnergyAustralia appreciates the Tribunal's recognition of the cost of non-bank cheque defaults in its direction to the NSW Government.

As currently drafted, we do not believe the draft Determination would adequately cover the situation in the event that the Electricity Supply Act (ESA) is amended to allow standard retail suppliers to charge a fee for dishonoured direct debit payments. Some minor drafting amendments could ensure that if the ESA was amended in such a way, standard retail suppliers would be in a position to levy a charge for such dishonoured payments. The following amendments would appear necessary:

- in clause 16(b), insert the words indicated:

> A *standard retail supplier* may not impose on or require from a *customer* a security deposit, late payment fee or fee for a dishonoured cheque or direct debit payment (whether or not described in those terms) except as permitted by this Part.

- in clause 17 (Table):

(a) in Item 1, column headed "Regulated retail charge", after the words "Fee for a dishonoured cheque" add the words "or direct debit payment";

(b) in Item 1, column headed "Maximum amount", after the words "cheque" insert "or direct debit payment";

- in clause 18, making the following changes:

> **18. Fee for a dishonoured cheque or direct debit payment**
>
> (a) The maximum that a *standard retail supplier* may charge a *customer* for a dishonoured cheque or direct debit payment is the corresponding amount listed in item 1 of the Table.
>
> (b) A *standard retail supplier* may charge a *customer* for a dishonoured direct debit payment if, and only if, the ESA is amended to permit a regulated retail charge to be imposed for a dishonoured direct debit payment.
>
> (c) A *standard retail supplier* may only impose such a charge if the *standard retail supplier* actually incurs a bank or other financial institution fee for that dishonoured cheque or direct debit.

- amending the definition of "regulated retail charge" in the following way:

> ***regulated retail charge*** means a security deposit, late payment fee or fee for a dishonoured cheque or direct debit payment of an amount specified in this determination.

The changes identified above should allow the Determination to accommodate a change to the ESA to include defaults on direct debit payments.

8 WEIGHTED AVERAGE COST OF CAPITAL

EnergyAustralia believes that the proposed capital structure range of 30% to 40% (measured by debt to total assets) is too high for a stand-alone retail business. Retail businesses operate at the riskiest end of the disaggregated electricity market given their:

- Exposure to competition and wholesale electricity markets
- Volatile and fluctuating cashflows
- Higher operational risk
- Intangible assets (i.e. largely comprising of customer goodwill).

These factors severely limit the borrowing capacity of a stand-alone retailer. A stand alone retail business would require significantly stronger financial ratios relative to an energy network or integrated energy utility in order to achieve an investment grade credit rating.

The 'expected returns' analysis undertaken by IPART's consultants provides that under IPART's draft determination, a mid-point enterprise valuation of $638 per customer is achieved[18]. Based on the mid-point capital structure range of 35%, this translates to loan debt of around $223 per customer and annual interest costs of around $16 per customer.

Assuming an average annual customer bill of $1000 and an allowed EBIT margin of 4% (i.e. net of depreciation), the resultant EBIT interest cover is 2.5 times (i.e. $40 / $16). EnergyAustralia believes that this is well below the EBIT interest cover required for a stand-alone energy retailer to achieve an investment grade credit rating.

Standard and Poor's published the following EBIT interest cover ranges for generation utilities (note that ratio ranges were not published for retail businesses as Standard & Poor's argue that to operate solely as an energy retailer is "not conducive to strong credit ratings")[19] . As generation utilities also operate in a highly competitive market, they represent a reasonable benchmark for retail business credit worthiness (although arguably, a stand-alone retailer is riskier than a generation utility due to the absence of tangible retail assets).

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[18] Frontier Economics and Strategic Finance Group, *Mass Market New Entrant Costs and Retail Margin*, March 2007, Page 59

[19] Standard & Poor's, *Project & Investment Finance*, October 2002, Page 60

Generation Utilities	‘A’	‘BBB’	‘BB’
EBIT Interest Cover	4.0 to 6.0	3.0 to 5.0	2.0 to 3.5

Table 8 - Interest cover for generation utilities

EnergyAustralia believes that IPART should adopt a maximum target capital structure of 20% in determining WACC. Based on the above analysis, this translates to an EBIT interest cover of around 4.4, comfortably within the ‘BBB’ range published by Standard & Poor’s for generation utilities.

Adoption of 20% debt to total assets, together with the mid-point WACC parameters adopted in IPART’s Draft Determination, translates to a mid-point real pre-tax WACC of 9.7% (compared to 8.6% under 35% debt to total assets assumptions).

Alternatively, should IPART retain 30% to 40% debt to total asset assumptions, EnergyAustralia believes that IPART should significantly increase the debt margin to reflect substantially lower credit rating outcomes under these assumptions.

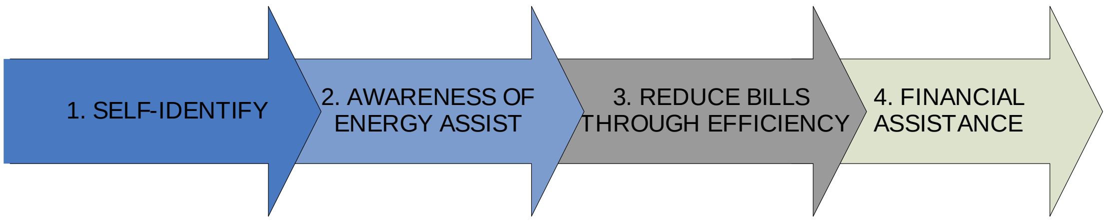
EnergyAustralia believes it is reasonable to update the interest-sensitive parameters of the weighted average cost of capital before finalising its Determination.

9 APPENDIX A – ENERGYAUSTRALIA'S EXPANDED HARDSHIP POLICY

EnergyAustralia is proposing an expanded customer hardship program as part of the new Regulated Retail Price Determination. An expanded customer hardship program will be more targeted and effective at assisting customers in genuine hardship. Engaging with the customer at an earlier stage in the billing cycle will prevent unnecessary and costly debt collection activities, including disconnections.

The aim is to introduce EnergyAssist initiatives to assist customers in efficiently managing their energy consumption and improve their payment discipline, reducing the likelihood of accruing large debts that may be difficult or impossible for them to discharge. Effective assistance should also ensure EnergyAssist customers are on the program for a shorter period, reducing the overall number of customers – and the cost of the overall program – in the long term.

The initiatives proposed in this paper have been developed following consultation with representatives from the office of the Energy & Water Ombudsman (EWON) and the Public Interest Advocacy Centre (PIAC). In addition, much has been drawn from EnergyAustralia's own experiences from implementation of the EnergyAssist program. The initiatives fall into four main areas that address the various stages of customer involvement in the EnergyAssist program:



1. SELF-IDENTIFY

"I'm in financial distress"

Customers must be in a position to identify as being in hardship. Advice from stakeholders indicates this is a significant hurdle. The only reliable method of detecting and assisting customers who are having difficulty paying their bills is to provide an environment in which customers feel confident and comfortable to communicate their current inability to pay at an early stage. Additionally, EnergyAustralia must be adequately resourced to assist those customers as identifying in financial hardship.

2. AWARENESS OF ENERGYASSIST

"EnergyAustralia can help me through these tough times"

Many customers experiencing payment difficulty are unaware that EnergyAustralia offers a hardship program. A precursor to measures aimed at encouraging customers to self identify is to increase awareness of EnergyAustralia's views regarding customer hardship, the existence of its customer hardship program and to encourage customers to contact EnergyAustralia if they are experiencing difficulties in paying their bills as soon as possible (and before their debts grow too high).

3. REDUCE BILLS THROUGH EFFICIENCY

"EnergyAustralia can show me how to save money on my energy bills by using electricity more efficiently"

All customers (including vulnerable customers) should be informed about energy, energy consumption and energy conservation. Without this understanding customers' behaviour cannot change. Energy 'literacy' for vulnerable customers is particularly important and serves a genuine opportunity to reduce their energy bills.

4. FINANCIAL ASSISTANCE

"EnergyAustralia will give me a helping hand in trying to pay my electricity bill"

Although we can empower the customer to make sensible decisions about the way they use energy, and in turn reduce their energy bills, it is important that the EnergyAssist team is also provided with the case management tools to help customers financially. It is not uncommon for customers on EnergyAssist to carry forward an old energy debt which they feel they can never discharge or, alternatively, lack the financial discipline to pay regularly. Despite efforts to use energy more efficiently, some customers may also face a high fixed charge as a proportion of their total bill which can discourage efforts to reduce their consumption. By expanding the case management tools which target these key financial obstacles, the EnergyAssist team will be better placed to help customers and shorten the time these customers spend on the EnergyAssist program.

A summary of the initiatives are set out on the following page:

Step	Initiative
1. SELF-IDENTIFY	**Initiative 1.1**. Contact Centre empathy and sensitivity training so that customers can readily identify themselves to EnergyAustralia as being in financial hardship.
	Initiative 1.2. Contact Centre training on existing low level assistance programs to assist customers when they first identify as being in financial hardship or when EnergyAustralia recognises they are experiencing difficulties paying their bills.
	Initiative 1.3. Contact Centre training on when it is appropriate to establish CentrePay arrangements, as opposed to other payment methods.
2. AWARENESS OF ENERGY ASSIST	**Initiative 2.1**. Increase awareness of EnergyAustralia's assistance measures through notification to all residential customers annually.
	Initiative 2.2. Articulate EnergyAustralia's hardship policy and include it on EnergyAustralia's website.
	Initiative 2.3. Provide information and resources for culturally and linguistically diverse (CALD) customers, including translation of brochures into community languages and provision of interpreter services at customer education forums.
3. REDUCE BILLS THROUGH EFFICIENCY	**Initiative 3.1**. Provide customer (and community support group) education on energy usage and efficiency, largely through education forums at community centres.
	Initiative 3.2. Provide new small retail customers with energy efficiency information in the form of a brochure accompanying the existing welcome letter and 'EnergyAustralia & You'.
	Initiative 3.3. Provide an onsite energy audit to certain EnergyAssist customers.
4. FINANCIAL ASSISTANCE	**Initiative 4.1**. Adequately staff EnergyAssist to carry out its existing functions and the new initiatives proposed in this paper. Improve ratio of case workers to EnergyAssist customers to a level consistent with industry average.
	Initiative 4.2. Introduce a criteria-based payment matching scheme as a tool for customers on the EnergyAssist program burdened by aged debt.
	Initiative 4.3. Introduce a criteria-based 'basic tariff' (no daily fixed charge) to provide stronger price signal to reduce energy usage.
	Initiative 4.4. Increased No Interest Loan Scheme (NILS) financing and promotion.

10 APPENDIX B – ADJUSTMENT OF OFGEM OPEX

PES	1998/99 Under 100kW 1st tier supply business costs[20]	Exceptional Costs	Transfer from Distribution To Supply[21]							Adjustment for additional EESoP costs	Adjuster business supply cost	£ / customer[22]	$ / customer[23]
			Advertising & marketing	Customer Services	Billing	Metering	Corporate	Other	Cost apportionment to <100 kW & 98-99£				
	(98-99)£M	IGNORE*	(97-98)£M	(97-98)£M	IGNORE*	IGNORE*	(97-98)£M	(97-98)£M	(98-99)£M	IGNORE*	(98-99)£M	(06-07)£	(06-07)$
Eastern	63.3		+0.8	+15.3			+5.5	-	+0.1		85.0	31.0	**104**
East Midlands	51.6		+3.6	+2.3			+5.4	-	+0.3		63.2	32.8	108
London	53.5		+1.5	+21.8			+2.3	+5.5	+0.9		85.5	37.0	109
Manweb	26.1		+4.6	+4.9			+3.5	-	+0.4		39.5	34.9	110
Midlands	64.8		-	+1.5			+2.4	-	+0.1		68.8	33.6	125
Northern	43.8		+0.9	+5.1			+1.9	-	+0.1		51.8	32.7	117
NORWEB	63.2		+1.1	+6.7			+3.8	-	+0.3		75.1	35.2	113
SEEBOARD	47.9		+5.0	+11.5			+1.9	-	+0.5		66.8	38.6	110
Southern	56.9		+1.0	+4.7			-	-	+0.1		62.7	36.5	119
SWALEC	24.9		+1.7	+3.8			+2.9	-	+0.1		33.4	32.3	130
South Western	27.1		-	+2.7			+1.9	-	+0.2		31.9	31.8	123
Yorkshire	59.1		-	+8.0			+2.1	+0.1	-0.1		69.2	52.5	109
ScottishPower	45.9		+5.3	+2.0			+3.7	-	+0.2		57.1	31.0	107
Hydro-Electric	50.8		-	+1.4			+3.1	-	+0.1		55.4	32.2	**177**
* Identified by Frontier Economics as rendering benchmark "less relevant" and so are ignored													

[20] Ofgem, *Reviews of Public Electricity, Suppliers 1998 to 2000, Supply Price Control Review, Final Proposals*, December 1999, p 28, Table 6.3.

[21] Ofgem, *Reviews of Public Electricity Suppliers 1998 to 2000, Distribution Price Control Review, Final Proposals*, December 1999, p 16, Table 2.2.

[22] Converted to £ per customer using a customer base derived from the £ / customer in Table 6.4 divided by "Adjusted business supply cost £M" in Table 6.3 of Ofgem Final Supply Review.

[23] Conversion ratio of 3.37, based on the average uplift from British £ to Australian $ provided in Frontier Economics Final Report on Retail Costs and Margin, p 31, Table 2 ($87.29 / £25.92)

11 APPENDIX C – KPMG REPORT FOR ENERGYAUSTRALIA ON BENCHMARKING LATE PAYMENT FEES

Energy Australia

Addendum to Benchmarking Retail Operating Costs and Margins

The Costs Associated with the Late Payment of Bills by Customers

March 2007

This report contains 14 pages

EA07-LPF0320SSD-SAR

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1 Executive summary

This report supersedes an earlier report dated 14 December 2006 *Addendum to Benchmarking Retail Operating Costs and Margins: The Costs Associated with the Late Payment of Bills by Customers* with revised assumptions that underlie the estimate of the costs associated with the late payments of bills by customers.

According to assumptions regarding the scale of operations of a Mass Market New Entrant ("MMNE") set out in this report, we estimate the costs associated with the late payment of bills for an MMNE to be within the range of $1.37m pa and $2.37m pa. This estimate reflects the full range of costs likely to be incurred including issuing reminder and disconnection warning notices, making reminder calls and the costs associated with working capital. As this report notes:

- Some of these costs were identified in our report the *Benchmarking of Retail and Operating Costs and Margins*. If we remove these costs then the estimate of late payment costs falls to between $1.01m pa and $1.80m pa; and

In order to recover these costs via a late payment fee it is necessary to identify a point in the billing cycle when a customer becomes liable for this service. The current determination covering retail prices and charges allows a late payment fee to be levied on or after the fifth business day after the due date and only after the customer has been notified in advance that the late payment fee will be charged if the account is not paid.[1] It is on this basis that we have assumed that the late payment fee is levied on all customers that receive a disconnection warning notice.

Our benchmarking indicates that an MMNE would issue between 117,000 and 197,600 disconnection warnings in a year and hence issue a similar number of late payment fees. As a result the level of the fee necessary for an MMNE to recover the costs of late payment would be as follows:

Table 1: Estimate of late payment fees

Late payment fee base	2005/06 Benchmark	
	Low	High
Total costs	**$11.71**	**$11.98**
Adjusted costs (excludes costs included in our previous work[2])	$8.63	$9.10

[1] IPART, *Determination of Regulated Retail Tariffs and Regulated Retail Charges for the Period 1 July 2004 to 30 June 2007*, Schedule 2.
[2] *Benchmarking of Retail and Operating Costs and Margins* report

2 Introduction

2.1 Background

EnergyAustralia has engaged KPMG to benchmark retail operating costs and margins for a Mass Market New Entrant ("MMNE"). This work is to inform EnergyAustralia's response to the Independent Pricing and Regulatory Tribunal's ("IPART") review of electricity retail tariffs for the period 2007-10.

In December 2006 KPMG provided an addendum report to EnergyAustralia focused on the costs associated with the late payment of bills by customers. This utilised a bottom-up approach to provide low and high range estimates of an allowance for a MMNE. On 15 March 2007 EnergyAustralia advised that its original assumptions were inaccurate and requested an amended version of the addendum report. Specifically EnergyAustralia requested that the costs associated with field visits for debt collection be included in the analysis (a copy of the letter is attached in the appendix to this report).

This addendum should be read in conjunction with our previous report (*Benchmarking Retail Operating Costs and Margins*, September 2006) to understand important contextual issues, assumptions, qualifications and methodology. Further, the addendum report dated December 2006 is superseded by this revised addendum report. With the exception of the changes noted above, these two reports are identical.

2.2 The late payment process

The late payment of invoices by customers imposes a range of costs on retailers depending upon the length of time the payment is delayed and the activities undertaken by the retailer to recover outstanding revenues. The activities undertaken by NSW retailers to recover payments after the initial due date include:

- Issuing a reminder notice;
- Issuing a disconnection warning notice;
- Telephone calls to customers;
- Field visits to customers; and
- Disconnection of services.

These last two items are incurred by the relevant distribution network service provider, with NSW retailers passing through the costs to the customer. In addition to the costs associated with each of the above activities, delays in collection of payments from customers will increase the amount of working capital required by a retailer.

In developing benchmarks for the costs of late payment we have, in the first instance, estimated the incremental or additional costs[3] likely to be incurred as a result of late payment. In addition, we have provided an indication of the likely magnitude of those costs on a stand alone[4] basis. This is because we understand that IPART intends to set late payment fees on a fully cost reflective basis.

The challenges of estimating the stand alone costs associated with late payment should not be underestimated. This is because late payment is part of the "normal" process of credit collection for a retail business. For example, the difficulties arise because:

- The relevance of each step in the process of credit collection for late payment is a matter of judgement; and
- It is extremely difficult to attribute precisely the costs associated with some activities between "normal" payment and late payment (eg working capital).

It is, however, reasonable to assume that late payment would make a disproportionately large contribution to some of these costs. A fully cost reflective late payment fee could therefore be higher than we have estimated.

Our estimate of the stand alone costs therefore implicitly double counts some of the costs included in our estimate of costs for an MMNE in our earlier report. This is done to demonstrate the magnitude of costs that could, in principle, be collected under a cost reflective late payment fee. If this were to occur, these costs would not need to be recovered in the general operating allowance indicated in our earlier report.

2.3 Volume assumptions

This report makes use of some assumptions and results obtained from our previous benchmarking work with EnergyAustralia. We state them in the table below.

Table 2: Volume assumptions applied in our calculations for late payment fee of an MMNE

Input	Assumption
Customer numbers	250,000
Billing intervals	245,000 customers billed quarterly
	5,000 customers billed monthly
Reminder notices	30% to 40%
Annual revenue per customer	$1,000 pa

[3] We have adopted the term "incremental" costs in the context that these costs are incremental to those costs developed in our previous work.
[4] We have adopted the term "stand alone" costs in the context that these costs would be added to the incremental costs to determine the total cost associated with late payment.

2.4 Disclaimer

Inherent Limitations

This report has been prepared as outlined in our engagement letter. The procedures outlined in this report constitute neither an audit nor a comprehensive review of operations.

No warranty of completeness, accuracy or reliability is given in relation to the statements and representations made by, and the information and documentation provided by, EnergyAustralia consulted as part of the process.

KPMG have indicated within this report the sources of the information provided. We have not sought to independently verify those sources unless otherwise noted within the report.

In the course of our work, projections have been prepared on the basis of assumptions and methodology which have been described in our report. It is possible that some of the assumptions underlying our projections may not materialise. Nevertheless, we have applied our professional judgement in making these assumptions, such that they constitute an understandable basis for estimates and projections. Beyond this, to the extent that certain assumptions do not materialise, then it must be appreciated that our estimates and projections of achievable results will vary.

KPMG is under no obligation in any circumstance to update this report, in either oral or written form, for events occurring after the report has been issued in final form.

The findings in this report have been formed on the above basis.

Third Party Reliance

This report is solely for the purpose set out in our engagement letter and for EnergyAustralia's information which includes the use of this information in EnergyAustralia's response to the IPART Issues Paper. It is not however, to be used for any other purpose or distributed to any other party without KPMG's prior written consent.

This report has been prepared at the request of EnergyAustralia in accordance with the terms of KPMG's engagement letter. Other than our responsibility to EnergyAustralia, neither KPMG nor any member or employee of KPMG undertakes responsibility arising in any way from reliance placed by a third party on this report. Any reliance placed is that party's sole responsibility.

3 Incremental costs of late payment

This section outlines the incremental costs a MMNE is likely to incur as a result of late payment. This includes:

- Costs of administering (printing and posting) disconnection warning notices;
- Call centre outbound calls; and
- Costs of conducting field visits.

Our earlier work[5] includes the costs associated with reminder notices, disconnection costs and the opportunity cost associated with maintaining sufficient working capital. These costs are discussed further in Section 4.

3.1 Reminder and disconnection warning notices

When a customer fails to pay their bill, a reminder notice is sent out to prompt the customer to pay. This is followed by a disconnection warning notice if the customer fails to pay the bill on time.

In NSW the billing cycle and notice requirements for disconnection are stipulated as follows:[6]

- 12 business days: initial pay-by-date;
- 13 business days: issue first disconnection notice (ie reminder notice);
- 20 business days: issue second disconnection notice; and
- Further attempts (ie telephone calls and field visits).

Information obtained for private retailers on the extent of reminder and disconnections warning notices are shown in the table below[7]. This indicates that there is a significant range in the extent to which reminder notices and disconnection warning notices are sent out to customers.

The available information indicates that between 19% and 60% of customers are issued a reminder notice. Of these between 28% and 74% then receive a disconnection warning notice.

[5] KPMG, *Benchmarking retail operating costs and margins*, September 2006, and KPMG, *Addendum to Benchmarking Retail Operating Costs and Margins*, November 2006.
[6] Energy Retailers Association of Australia (ERAA), National Regulatory Consistency, *Priority Code and Regulatory Consistency Issues.*
[7] ESC, *Final Decision: Energy Code*, May 2004, Appendix 2, p. 36

Table 3: Comparison of reminder and disconnection warning notices across retailers

Reminder and warning notices	2003/2004 Benchmarks				
	AGL (Vic)	AGL Gas (NSW)	AGL (SA)	Origin[8]	TXU[9]
Reminder notices as % of initial bills	21.3[10]	21.0	21.0	60.0	19.0
Disconnection warnings as % of reminder notices	36.3[11]	31.0	28.0	43.0	74.0

The information outlined in the Table above is consistent with our earlier report, which assumed that reminder notices are issued for between 30% and 40% of customers. This range was previously agreed with EnergyAustralia as being indicative of the experience of some retailers in NSW. In addition it is our expectation that an MMNE would be relatively intolerant of late payments.

To determine the number of disconnection warning notices issued we have adopted a range of 37.5% to 47.5% of reminder notices. This range was determined based on the average (42.5%) of the five results in the table above adjusted for a ±5 percentage point range (with the ± 5 percentage point range a subjective judgement).

The following table outlines the benchmark cost estimate for issuing disconnection warning notices for an MMNE.

Table 4: Cost of disconnection warning notices

Disconnection warning notices	2005/06 Benchmark	
	Low	High
Number of reminder notices	312,000	416,000
Disconnection warnings as % of reminder notices	37.5	47.5
Cost per invoice[12]	$0.73	$0.73
Total cost for disconnection warning notices ($m)	$0.09	$0.14

3.2 Reminder calls

A MMNE may call customers that do not pay after receiving a disconnection warning notice. This activity can be contracted to a call centre.

Unlike inbound calls which generally deal with requests for information, collection calls are usually managed by operators who have considerably more experience in credit management. In addition adequate training on the MMNE's company policies and procedures and compliance with debt collection regulations need to be provided. The general tasks undertaken may include:

[8] Data is based on one billing cycle in the first quarter of 2004.
[9] Data reported for TXU is overall average for electricity customers and not based on any particular period.
[10] An average of AGLE (22%), AGLVe (19%) and AGLVg (23%) which were previously known as Solaris Energy, Pulse Energy and Ikon Energy respectively.
[11] An average of AGLE (34%), AGLVe (61%) and AGLVg (14%) which were previously known as Solaris Energy, Pulse Energy and Ikon Energy respectively.
[12] See KPMG, *Benchmarking retail operating costs and margins*, September 2006 page 34.

- Notifying or locating customers with delinquent accounts and attempting to secure payment;
- Telephoning the customer to determine the reason for non-payment; and
- Encouraging payment of outstanding amounts or some form of alternative payment arrangements.

In the absence of publicly available data we have adopted data provided to us by EnergyAustralia to estimate the volume of reminder phone calls to be made. Based on monthly data over a 12 month period, on average 24% of customers that receive disconnection warning notices require a reminder phone call. Given the variability in the data over this period we have applied a subjective range of $\pm$ 5 percentage points to produce a lower and upper bound estimate of 19% to 29%.

In computing call centre costs, we assume that an agent is able to deal with 20 calls per day (an average of 3 calls per hour for 6.5 hours) and that in a year a total of between 22,000 and 57,000 calls would need to be made requiring between 1,100 and 2,900 call centre agent days. Consequently, the labour cost is derived from the amount of full-time equivalent (FTE) agents required to handle the assumed volume of calls.

Consistent with our approach in our earlier report, ACA Research's[13] recommended ratios of contact centre staff suggest that the MMNE will need around 7 to 15 FTEs to handle this activity. This translates to total labour cost of \$0.45m to \$0.85m.[14]

As per our earlier report the ACA research benchmark suggests that labour costs comprise 66% of total call centre costs (including the computer information systems). Hence, total call centre costs are likely to be between \$0.685m pa and \$1.29m pa.

Table 5: Call centre costs

Call centre costs	2005/06 Benchmark	
	Low	High
Reminder calls made	22,000	57,000
Total FTEs	7	15
Labour costs (\$m pa)	\$0.45	\$0.85
Percentage of labour cost to total call centre cost	66%	66%
Total call centre cost (\$m pa)	\$0.68	\$1.29

[13] ACA research, 2002/03 and 2003/04 National regulatory requirements – Comparative summary for retailers to small electricity customers in Queensland, Office of Energy. ACA Research is an Australian-based full service market research consultancy which conducts a wide range projects across different industries. It is a member of the Market Research Society of Australia (MRSA).

[14] 78 FTEs based on a total of 1 manager (\$150,000), 1 team leader (\$65,000), 4 agents (\$48,000) and 1 support staff (\$42,000). At the higher end of the range, 15 FTEs are based on a total of 1 manager (\$150,000), 2 team leaders (\$65,000), 11 agents (\$48,000) and 1 support staff (\$42,000). All salaries for contact centres as benchmarked by Hays Salary Survey 2006.

These costs are in addition to those identified in our earlier report, where we identified call centre costs for managing in-bound calls only.

3.3 Field visits and disconnections

Distribution network service providers are responsible for the conduct of field visits for the disconnection of service. IPART sets the level at which charges can be set for field visits as follows:[15]

- A disconnection visit (resulting in acceptable payment) – $35
- Disconnection of services – $70 (disconnected at the meter box), $117 (at the pole top/pillar box).

IPART allows retailers to pass these costs through to customers. EnergyAustralia have advised that these costs are not recovered via late payment fees and requested that our analysis of the costs of late payment exclude these activities.

In addition to the above, an MMNE may conduct field visits as part of their debt recovery operations. Such field visits are conducted to:

- Notify a customer of their outstanding debt upon their inaction towards previous disconnection notices and collection calls;
- Receive payment or discuss satisfactory credit arrangements; and
- Agree to defer action because of reasons such as death or illness.

We have assumed that field visits are conducted by social workers, who are well equipped to deal with customer hardship circumstances. In some instances, households can be experiencing financial hardship and are therefore genuinely unable to pay. Field representatives will then discuss ways of assisting their financial difficulty. For example, retailers like AGL implement hardship programs which help customers with payment arrangements and management of their energy consumption[16].

In the absence of publicly available data we have referred to information supplied by EnergyAustralia that identifies the number of field visits conducted over a 12-month period. On average 9.4% of customers that receive a disconnection warning notice also received a field visit. However given the variability in the numbers over a year we have adopted a range of 9% to 10% for establishing the benchmark.

Our research indicates that the annual salary of a social worker in the range of $45,000 to $59,000, with an average of $50,000.[17] We met with EnergyAustralia's Debt Management

[15] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination, 2004, Annexure 3
[16] Based on AGL's submission on additional information regarding late payment fees, published at www.esc.vic.gov.au
[17] Based on an internet salary survey prepared by www.mycareers.com.au accessed on 15 March 2007.

division to ascertain the number of debt collection field visits that can be performed by a trained employee. Based on the experience of EnergyAustralia we have assumed that 35 field visits can be conducted in one day by a trained employee, supported by call centre staff.[18] Assuming that a social worker is able to conduct 35 field visits per day, this will require between 2 and 3 FTEs at a cost of $0.12m and $0.17m.

In addition account has been taken of the additional volume of calls to be received by the call centre (i.e. between 10,530 and 19,760 per annum). Applying the same methodology as that used in section 3.2 above, this equates to an additional 2 to 3 call centre agents

Table 6: Field visit costs

Field visit cost	2005/06 Benchmark	
	Low	High
Total visits made	10,530	19,760
Total FTEs	2	3
Salary & on-costs per FTE	$57,500	$57,500
Labour costs ($m pa)	$0.12	$0.17
Additional call centre agents (FTEs)	2	3
Labour costs ($m pa)	$0.10	$0.14
Percentage of labour cost to total call centre cost	66%	66%
Total call centre cost ($m pa)	$0.13	$0.19
Total Field Visit Costs ($m pa)	$0.24	$0.37

[18] EnergyAustralia advised that the debt collector telephones the call centre after each visit so as to update each customers billing records to reflect the outcome of each collection field visit.

4 Stand alone costs of late payment

Section 3 identifies the incremental costs that are potentially associated with late payments. These costs are outlined below to indicate the likely magnitude of late payment costs on a "stand alone" basis. The true stand alone cost is likely to be higher than those presented here as we have not been able to attribute costs such as corporate overheads and management, customer information systems, information technology and travel related costs for field visits.

The extent of the double counting outlined in this section is of a low scale, in the order of $0.23m pa to $0.30m pa for reminder costs and $0.13m pa to $0.27m pa for working capital. Each of these items are small components within our estimates of total operating costs ($20.70m pa to $22.00m pa) and the investment in working capital ($24.3m pa to $32.8m pa).

4.1 Reminder notices

In our earlier report we assumed that reminder notices are issued to between 30% and 40% of initial bills. This range is within that outlined above in Table 3 and was previously agreed with EnergyAustralia as being appropriate for the NSW market. Hence the benchmark cost of issuing reminder notices is between $0.23m pa and $0.30m pa.

Table 7: Cost of reminder notices

Reminder notices	2005/06 Benchmark	
	Low	High
Number of initial bills	1,040,00	1,040,000
Reminder notices as % of initial bills	30.0	40.0
Cost per invoice[19]	$0.73	$0.73
Total cost for reminder notices ($m)	$0.23	$0.30

4.2 Working capital costs

To provide an indicative estimate of the costs of working capital associated with late payment, we have assumed the following billing cycle:

- 12 business days: initial pay-by-date;
- 13 business days: issue first disconnection notice;
- 20 business days: issue second disconnection notice; and
- 27 business days: notice of disconnection.[20]

[19] KPMG, *Benchmarking retail operating costs and margins*, September 2006.
[20] Late payment does not change the magnitude of working capital requirements, but does change the length of time for which some of that capital is required.

Based on this timing we determine the average level of debt owing at each stage of the cycle and applied the pre-tax nominal cost of capital (11.6% to 16.4%) estimated in our previous work.

Table 8: Days overdue

	Activities in the billing cycle					
	Due date	Reminder	Warning notices	Calls	Visits	Disconnection
Day in the billing cycle (business days)	12	13	20	23	25	27
Day in the billing cycle (calendar days)	12	17	26	31	33	37
Calendar days overdue		1 - 9	10 - 14	15 - 16	17 - 20	21 +
Midpoint of days overdue for activity		4.5	2.5	1	2	

Based on the assumptions presented for the MMNE (refer to both Table 2 above and our previous report) we have estimated a lower range and higher range benchmark opportunity cost, which is presented in the following table.

Table 9: Cost of funds

	Activities in the billing cycle					
	Total	Reminder	Warning notices	Calls	Visits	Disconnection[21]
Annual revenue per customer	$1,000					
Lower range						
Total as % of all customers		30%	11.25%	2.14%	1.01%	0.45%
Number of customers		75,000	28,125	5,344	2,531	1,125
Outstanding bill ($m pa)		$75.00	$28.13	$ 5.34	$ 2.53	n/a
Cost of funds		$107,000	$22,000	$ 2,000	$ 2,000	n/a
Total cost of funds	$133,000					
Upper range						
Total as % of all customers		40%	19.00%	5.51%	1.90%	0.76%
Number of customers		100,000	47,500	13,775	4,750	1,900
Outstanding bill ($m pa)		$100.00	$47.50	$13.78	$ 4.75	n/a
Cost of funds		$202,000	$ 53,000	$ 5,000	$ 4,000	n/a
Total cost of funds ^	$266,000					

^ Due to a rounding error the value displayed does not equal the sum of the values presented.

[21] If disconnected it is assumed to become a bad debt which is treated differently to late payment, and therefore excluded.

A Letter from EnergyAustralia

15 March 2007

EnergyAustralia™

570 George Street
Sydney NSW 2000
Telephone 13 1525
+61 13 1525
Facsimile (02) 9269 2830
www.energy.com.au

Address all mail to
GPO Box 4009
Sydney NSW 2001
Australia

Mr Craig Mickle
Director – Risk Advisory Services
KPMG
10 Shelley St
SYDNEY NSW 2000

Dear Craig

EnergyAustralia's Request to amend KPMG report on Late Payment Fees

I write to you seeking amendment to the report EnergyAustralia commissioned KPMG to develop entitled *Addendum to Benchmarking Retail Operating Costs and Margins, The Costs Associated with the Late Payment of Bills by Customers*. This report has been released to IPART on a commercial-in-confidence basis. The report has not been released publicly.

Since the release of the report, it has come to our attention our advice provided to KPMG regarding the costs associated with field visits while, at the time, was provided in good faith based on our best understanding of current practice, was nonetheless inaccurate. We are seeking to clarify the assumption held in the report related to field costs in order to better capture the true, discrete costs associated with late payment. This is particularly important given the Tribunal's interest in the range of cost estimates provided for their consideration, including those found in the KPMG report.

EnergyAustralia originally advised KPMG that a field visit to disconnect a customer is a service conducted by the distribution network businesses. The network business charges the retailer according to the rates allowed (regulated) by IPART. The retailer, in turn, passes this charge on to the customer. A field visit is also considered a network service where the field visit is conducted with an *intention* to disconnect, regardless of whether disconnection actually occurs.

However, field visits are also conducted where the intention is to collect payment or seek promise of payment. On these occasions, the cost of conducting the field visit is considered a debt recovery activity borne by the retail business directly. It is an alternative to an outbound reminder call. Unfortunately, the field visit cost of debt recovery was not captured in the aforementioned report. We request KPMG to amend the report to include the costs associated with field visits for debt collection.

If you have any queries please contact Michael Pennings on 02 9269 4918 or Phil Moody on 02 9269 7256.

Sincerely

Tim O'Grady
Executive General Manager Retail

Partner