Integral Energy

Review of Regulated Retail Tariffs and Charges for Electricity 2007 to 2010

Submission

to the

Independent Pricing and Regulatory Tribunal of NSW

7 September 2006

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Contents

1 Overview

This section provides an overview of the Integral Energy (Integral) Submission responding to the Independent Pricing and Regulatory Tribunal's (Tribunal) Discussion Paper DP85 (the Issues Paper) relating to the Review of Regulated Retail tariffs and Charges for Electricity 2007 to 2010 (2007 Retail Review).

The current Retail Determination (2004 Retail Determination) commenced on 1 July 2004 and will expire on 30 June 2007. The NSW Minister for Energy has asked the Tribunal to determine appropriate default retail tariffs and charges for a further three years until 30 June 2010.

1.1 Outcomes from the 2004 Retail Determination

Integral's default regulated retail tariffs are currently set at the target level as required in Clause 5.2 of the 2004 Retail Determination.

In the 2004 Retail Determination, the Tribunal used estimates of industry costs and retailer specific churn rates to build up a target tariff for the regulated retail businesses in NSW. A significant component in this retail cost build-up is the allowance for energy purchase costs.

The Tribunal has built up regulated target tariffs for Integral and the other NSW default retailers based on an allowance for energy purchase cost of $50 per MWh. This allowance comprises $47 per MWh for electricity costs based on an assessment of the Long Run Marginal Cost of generation and $3 per MWh for green energy costs.

The energy purchase allowance of $50 per MWh applies for all NSW regulated retailers and as such fails to reflect the differing costs faced by the retailers when purchasing energy for their specific default customer load profile.

In its 2004 Retail Determination, the Tribunal allowed prices to incorporate operating costs of $70 per customer. This allowance is well below the levels set by regulators in SA, ACT and Victoria in their more recent decisions, which have seen operating cost allowances of $84 to $92 per customer, or 20 percent to 31 percent higher than in NSW. The $70 per customer allowance as set by the Tribunal is below Integral's actual retail costs.

The allowed retail margin of 2 percent as contained in the 2004 Retail Determination has also proven to be well below the levels set by regulators in other jurisdictions. For instance, in SA the Regulator (ESCOSA) allowed a retail margin of 4 percent to 6.5 percent, while in Victoria the allowed margin was considerably higher. The allowed margins have, to a large extent, reflected varying views as to what factors should be recovered by regulated retailers, such as customer acquisition costs (included in SA) and working capital (included in SA and Victoria) and the risks faced by regulated retailers in the different states.

The 2004 Retail Determination also included the extensive use of side constraints. The use of side constraints effectively reduced Integral's ability to move its tariffs to cost reflective levels at the start of the current retail determination period, which is estimated to have cost Integral $12m[1] in foregone regulated retail revenue below the efficient allowance set by the Tribunal. Side constraints also impaired Integral's ability to rationalise obsolete tariffs.

The Tribunal's allowances for Integral's energy costs, operating costs and retail margin are, on an individual basis, below the levels set by regulators in other states in more recent determinations. When considered in total, this has resulted in regulated tariffs that are below cost reflective levels and below the levels set in other states. Integral believes that, while competition has been extensive in Integral's franchise area, it has been dampened, to some extent, by regulated tariffs that are below cost reflective levels.

1.2 2007 Retail Determination

There have been a number of significant changes in both the environment and the Terms of Reference (TOR) for this review.

Full retail contestability (FRC) has now been in place in New South Wales since January 2002. The competitive retail market has developed substantially during this time, in that:

- Customers have a choice of retailer;
- Customers have better awareness of their choices of retailer and supply options;
- FRC systems and processes facilitate transfer; and
- Customer churn is occurring where there is a price incentive.

The most significant differences between the TOR for the 2007 review and those for the 2004 review are:

- The Tribunal must ensure that regulated tariffs are at cost reflective levels for all small retail customers by 30 June 2010;
- The Tribunal is now required to recognise retailers' hedging, risk management and transaction costs against a backdrop of the cessation of the Electricity Tariff Equalisation Fund (ETEF);
- The Tribunal must consider an allowance for electricity purchase costs based on an assessment of the long run marginal cost (LRMC) of electricity for a portfolio of new entrant generation to supply the load profile of customers remaining on regulated tariffs;
- The Tribunal must recognise the Net System Load Profiles (NSLPs) of each standard retailer, as well as projected future changes in those NSLPs;

[1] IPART (2004), NSW Electricity Regulated Retail Tariffs 2004/05 to 2006/07 Final Report and Determination, Section 4.1.3, p17.

- The Tribunal must consider retail operating costs and margin based on a mass market new entrant rather than those for the existing standard retailers; and

- The TOR for this review do not explicitly state that the Tribunal is to have regard to the impact of its determination on customers.

The Tribunal's decisions in this review will need to focus on facilitating competition and the role of the market in "regulating" prices beyond 2010.

1.3 Integral's proposed regulatory principles

Integral believes that the following regulatory principles should be considered by the Tribunal in making its Determination on regulated retail tariffs and regulated retail charges:

- The retail electricity market is already competitive, obviating the need for ongoing regulated retail tariffs. Any ongoing regulation beyond 2010 should be for the purposes of customer protection.

- In order to facilitate competition and to support a viable retail business, regulated retail prices must:

  - Be at cost reflective levels within a reasonable transition period;

  - Incorporate an appropriate allowance for the hedging, risk management and transaction costs associated with the phase out of the ETEF and which recognise the "peakiness" of Integral's load profile;

  - Include a reasonable allowance for retail costs and margin; and

  - Allow for the full pass through of network charges.

- Regulated retail tariffs should be simple and provide for maximum flexibility for retailers to price efficiently and to eliminate obsolete tariffs.

- The approach must appropriately balance commercial and customer outcomes.

1.4 Key issues for Integral

Integral's objective is to work with the Tribunal and other stakeholders in the development of the 2007 Retail Review so that Integral can operate its regulated retail business on a commercial basis and manage pricing outcomes for small retail customers. Integral considers that, with the advent of competition, the 2007 Retail Review should be the last review of regulated retail prices, and that any ongoing retail regulation should be for the purposes of customer protection.The TOR specify a number of matters for consideration by the Tribunal. Integral responds to these issues within this submission. Based on Integral's experience under the 2004 Retail Determination, Integral's review of the TOR and the Issues Paper, the key issues for Integral in this review are:

- *Form of regulation for retail tariffs*

  A change is required in the form of regulation to reflect the objectives of the review, the change in the market context and to provide an appropriate transition to the removal of price regulation from July 2010.

  Integral believes that controls on regulated tariffs are no longer needed due to the increasing number of customers switching to competitive contracts and the development of retail competition. Price monitoring, while outside the current TOR, would be an appropriate, light handed form of regulation.

  However, given the TOR, IPART must seek to impose some form of price control. Integral believes that a minimalist change to the existing form of regulation should be implemented. This change would see a continuation of the current Network + Retail framework, but retail regulation would be focussed on the Retail component only. A move away from pricing constraints on individual tariffs to an annual “weighted average price cap” for aggregate retail prices against an annual forecast of aggregate retail costs would provide Integral with flexibility in setting regulated retail tariffs as part of the transition from price regulation.

- *Energy costs*

  The TOR for this review require IPART to consider an allowance for electricity purchase costs based on an assessment of the long-run marginal cost (LRMC) of electricity generation from a portfolio of new entrant generation to supply the load profile of customers remaining on regulated retail tariffs. There is also a need to recognise retailers’ hedging, risk management and transaction costs, given the Government’s decision to phase out the NSW ETEF scheme fully by the end of the period.

  The relationship that IPART develops between the LRMC and the allowance for energy costs under the phase out of ETEF will be critical in allowing retailers to fully recover their costs. A reliance on LRMC alone is not consistent with full cost reflectivity or effective retail market competition.

  Integral proposes a methodology for calculating an appropriate energy purchase cost allowance. This submission does not attempt to quantify either the hedging, risk management and transaction costs or the LRMC for Integral’s net system load profile (NSLP). Rather, the focus is on setting out proposals for such quantification for consideration by IPART and its consultants.

  The submission discusses the impact of the Integral NSLP on the energy cost allowance. Data for Integral suggests the energy purchase cost allowance for the Integral NSLP will be higher than for the other NSW NSLPs. This reflects the fact the Integral NSLP has the highest correlation with system wide peak demand and high pool price periods.

- *The level of retail margin*

  The retail margin should compensate retailers for costs not compensated for elsewhere in the framework.

The submission notes that there has been little previous analytical work in this area, as IPART (and other regulators) have relied on a comparison of margin determinations made by other regulators. In relation to the retail margin it is important, where practicable, to move to single national regulatory approach.

Many of the components of the margin are amenable to a direct calculation. This submission argues for such an approach and recommends that an appropriate retail margin for a new entrant should cover a return on, and amortisation of, customer acquisition costs, a return on and of physical systems, a return on working capital and an allowance for asymmetric risks.

This approach results in a margin increase from 2% to around 10% for residential customers. This change is largely explained by a return on and of investments in customer acquisition costs estimated at $524 per customer which are part of the costs a mass market new entrant retailer would face, as required to be considered by the TOR.

- *The level of retail costs*

It is important that all relevant costs are reflected in the estimate of the appropriate level of regulated retail tariffs. Exactly where those costs are reflected is of secondary importance, that is, whether they are incorporated within the estimates of retail margin, retail costs or energy costs.

In its 2004 Retail Determination, the Tribunal allowed prices to incorporate operating costs of $70 per customer. This allowance is well below the levels set by regulators in SA, ACT and Victoria in their more recent decisions, which have seen operating cost allowances of $84 to $92 per customer, or 20 percent to 31 percent higher than in NSW. The $70 per customer allowance as set by the Tribunal is below Integral's actual retail costs.

This submission focuses on the appropriate framework for consideration of retail operating costs with the expectation that costs will be higher than the $70 per customer previously allowed by IPART as the retail operating costs need to reflect a 'mass market new entrant'. It will be argued that the best proxy for these costs is Integral's existing cost structure, modified by the additional costs (or reduced costs in some cases) that a 'mass market new entrant' would face.

Integral provides more detailed responses to these key issues within this Submission.

1.5 Moving forward

Decisions on the form of regulation and detailed regulatory parameters will be critical to achieving competitive outcomes. These decisions need to reflect the role of regulated retail prices as safety net prices and the role of the market in "regulating" prices.

To achieve commercial outcomes and support a competitive market, Integral needs to have the flexibility to move to cost reflective tariffs as early as possible.

2 Purpose of submission

This Submission is made by Integral in relation to the Tribunal's investigation and report on regulated retail tariffs and regulated retail charges to apply between 1 July 2007 and 30 June 2010 under Division 5 of Part 4 of the Electricity Supply Act 1995 (the Act).

The investigation and report applies to regulated retail tariffs and charges for small retail customers.[2] These regulated retail tariffs act as safety net or default prices for customers who do not choose to participate in the competitive market.

The purpose of this Submission is to address issues raised by the Tribunal in its Discussion Paper DP85 released in July 2006. This Submission is structured as follows:

Section	Purpose	Details
3	Approach to the 2007 Regulated Retail Tariff Review	This Chapter discusses the basis for the Tribunal's approach to, and issues relevant to, the Tribunal's review of retail regulated prices, Integral's interpretation of the TOR and Integral's view on regulatory principles and objectives relevant to the review.
4	Current retail tariffs and competition	This Chapter provides an overview of Integral's current regulated retail tariff position and highlights key points on the current status of retail competition.
5	Form of regulation and price constraints	This Chapter sets out Integral's view on the form of regulation which will best assist in transitioning regulated tariffs to cost reflective levels over the period of review.
6	Energy costs	This Chapter sets out Integral's view on an appropriate method for determining the energy purchase cost allowance.
7	Retail margin	This Chapter sets out Integral's position on what the Tribunal should consider in allowances for various cost, risk and margin components
8	Retail operating costs	This Chapter sets out Integral's position on what the Tribunal should consider in the allowance for retail operating costs.
9	Customer assistance package	This Chapter sets out details of Integral's customer assistance package.
10	Miscellaneous charges	This Chapter sets out Integral's proposal for regulation of non-tariff charges including: - Late payment fee; - Security deposit; - Dishonoured bank transaction fee.

[2] Small retail customers for electricity are defined in the Act as a customer that consumes electricity at less than 160 MWh per year as prescribed in clause 7 of the Electricity Supply (General) Regulation 2001. A small retail customer is eligible for supply under a standard form customer supply contract.

3 Approach to the 2007 regulated retail tariff review

The purpose of this Chapter is to discuss the basis for the Tribunal's approach to, and issues relevant to, the 2007 Retail Review.

Integral notes the Government's TOR for the investigation and report on the setting of tariffs for small retail regulated customers and the significant differences between the TOR for the 2007 review and those for the 2004 review. Of particular importance is the requirement for the Tribunal to consider costs from the perspective of a "mass market new entrant" retailer and for an allowance for electricity purchase costs based on new entrant generation.

3.1 The Government's TOR for the Tribunal's review

The matters for consideration by the Tribunal are as follows:

For the purposes of section 43EB (2)(a) of the Act, the matters the Tribunal is to consider in making its investigation and report on the setting of tariffs for small retail customers to apply from 1 July 2007 to 30 June 2010 include:

- *An allowance for electricity purchase costs based on an assessment of the long-run marginal cost of electricity generation from a portfolio of new entrant generation to supply the load profile of customers remaining on regulated retail tariffs;*
- *Mass market new entrant retail costs;*
- *Mass market new entrant retail margin;*
- *An allowance based on long run marginal cost for retailer compliance with any Commonwealth Mandatory Renewable Energy Target (MRET) requirements and the licence requirements relating to the NSW Greenhouse Gas Benchmark Scheme, which takes into account price and volume;*
- *Energy losses as published by the National Electricity Market Management Company (NEMMCO);*
- *A mechanism to ensure network charges as determined by the Tribunal and the Australian Competition and Consumer Commission (ACCC) and the Australian Energy Regulator (AER) are fully recovered;*
- *Fees (including charges for ancillary services) as imposed by NEMMCO under the National Electricity Code;*
- *An allowance for expected movements in regulated components and NEMMCO fees;*
- *A mechanism to address any new, compulsory scheme that imposes material costs on the retailer;*
- *Recognition that ETEF will cease operation within the determination period;*

- *Recognition of hedging, risk management and transaction costs faced by retailers in the absence of the ETEF;*
- *Recognition of the forecasting risks faced by retailers in the absence of the ETEF;*
- *Recognition of Net System Load Profiles (NSLPs) for each standard retailer, as well as projected future changes in those net system load profiles;*
- *The requirement in the NSW Greenhouse Plan to require energy retailers to offer a 10 per cent Green Power component to all new (or moving) residential customer;*
- *The potential to simplify regulated tariff structures including the potential to remove obsolete tariffs.*

In addition, the TOR state that:

- *The Tribunal must consider the Government's policy aim of reducing customers' reliance on regulated prices and the effect of its determination on competition in the retail electricity market.*

Specifically the Tribunal is to take account of the following matters in undertaking its review:

- *Ensuring regulated tariffs cover the costs listed above;*
- *Consider the impact on demand management.*

The TOR also state that:

The Determination should ensure that:

- *Regulated retail tariffs and regulated retail charges are at cost reflective levels (including all the costs listed above) for all small retail customers by 30 June 2010;*
- *The setting of any 'price constraint' should allow the further rationalisation of regulated retail tariffs and movement to full cost recovery over the determination period.*

3.2 2007 Retail Determination

There have been a number of significant changes in both the environment and the TOR for this review.

Full retail contestability (FRC) has now been in place in New South Wales since January 2002. The competitive retail market has developed substantially during this time, in that:

- Customers have a choice of retailer;
- Customers have better awareness of their choices of retailer and supply options;
- FRC systems and processes facilitate transfer; and
- Customer churn is occurring where there is a price incentive.

The most significant differences between the TOR for the 2007 review and those for the 2004 review are:

- The Tribunal must ensure that regulated tariffs are at cost reflective levels for all small retail customers by 30 June 2010;
- The Tribunal is now required to recognise retailers' hedging, risk management and transaction costs against a backdrop of the cessation of the Electricity Tariff Equalisation Fund (ETEF);
- The Tribunal must consider an allowance for electricity purchase costs based on an assessment of the long run marginal cost (LRMC) of electricity for a portfolio of new entrant generation to supply the load profile of customer remaining on regulated tariffs;
- The Tribunal must recognise the Net System Load Profiles (NSLPs) of each standard retailer, as well as projected future changes in those NSLPs;
- The Tribunal must consider retail operating costs and margin based on a mass market new entrant rather than those for the existing standard retailers;
- The TOR for this review do not explicitly state that the Tribunal is to have regard to the impact of its determination on customers.

4 Current retail tariffs and competition

This Chapter will discuss the following issues related to current retail tariffs and competition:

- Description of Integral's current regulated retail tariffs.
- The extent of competition in the NSW retail electricity market.
- The extent of competition in vulnerable customer segments of the market.

4.1 Current regulated retail tariffs

Integral's default regulated retail tariffs are currently set at the target level as set out in Clause 5.2 of the 2004 IPART Retail Determination.

The following chart provides an indicative comparison of the average price paid by a default residential tariff customer consuming 7MWh per annum.

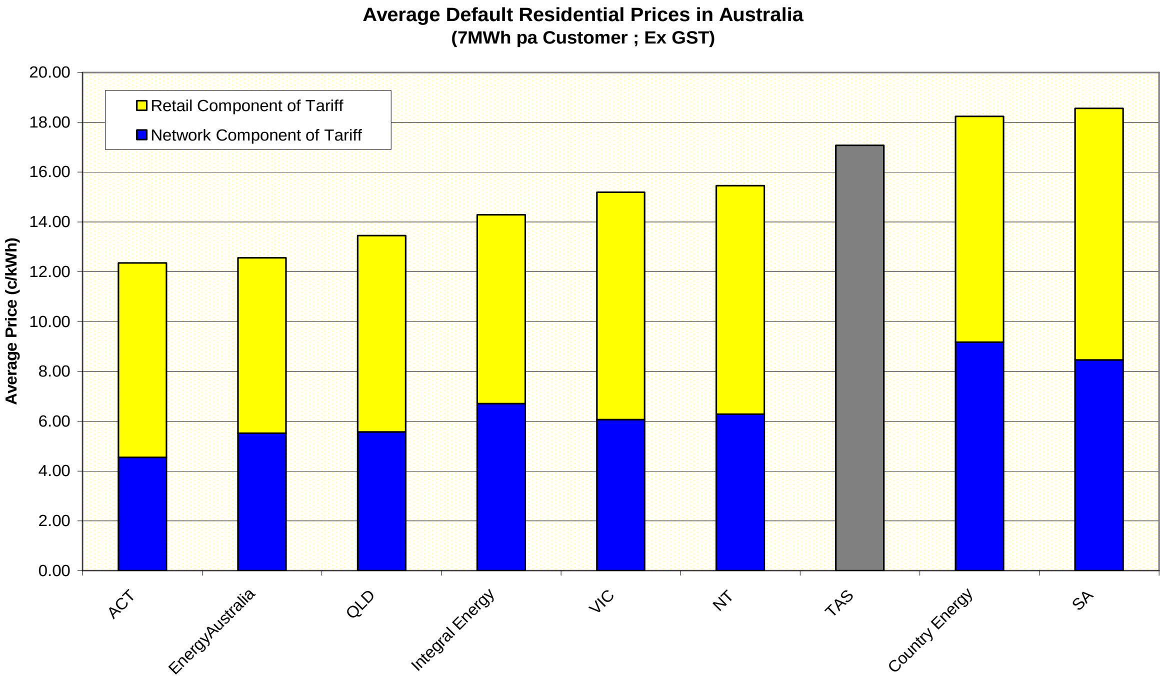

Figure 4.1 - Average default residential prices in Australia

Source: Various websites; analysis by Integral Energy

As can be observed in the above chart, the average default residential price for a customer consuming 7 MWh per annum in Integral Energy's franchise area is considerably lower than the average default residential price for a residential customer consuming 7 MWh per annum in most other areas of Australia.

Most importantly, the residential tariff comparison also shows that Integral's retail component is significantly less than the retail component observed in other jurisdictions.

4.2 Retail competition

Full retail contestability (FRC) has now been in place in NSW since January 2002. As stated in Section 3.2 the competitive retail market has developed substantially during this time.

The Ministerial Council on Energy (MCE) have developed a set of criteria to guide the Australian Energy Market Commission (AEMC)'s assessment of whether competition is effective in jurisdictional retail energy markets, as listed below:

- Independent rivalry in the market;
- Ability of suppliers to enter the market;
- The exercise of market choice by customers;
- Differentiated products and services;
- Prices and profit margins; and
- Customer switching behaviour.

Integral believes that an assessment based on the criteria developed by the MCE is likely to support the view that the extent of competition in the retail electricity market in NSW has evolved to the extent that the actions of competitors can be relied upon to ensure that no individual retailer is able to exercise market power to the detriment of competition and consumers.

It is important that an assessment of the extent of competition in the retail electricity market in NSW is undertaken prior to the completion of the 2007-10 retail determination period to allow for a smooth transition to the removal of price regulation in 2010.

Integral faces significant competition from a number of electricity retailers in its franchise area for residential and small business customers. Currently, there are eleven retailers with a licence to supply residential and small business customers in NSW[3]. Importantly, the extent of competition in Integral's franchise area is increasing with a significant rise in the number of new entrant retailers, such as Origin Energy, TRUenergy and Jackgreen. The recent increase in new entrants suggests that there are no significant barriers to entry associated with the NSW retail electricity market, with firms able to enter the market with relative ease.

The increase in competition is resulting in greater innovation on the part of retailers in the extent and nature of offers being made in response to the preferences of customers and the actions of competitors. Increased competition is also leading to greater awareness of the competitive market, resulting in a greater degree of active exercise of market choice by customers.

[3] IPART Website: www.ipart.nsw.gov.au/electricity/licensing_further_information_1.asp

As a result of increased retailer activity and growing customer interest in the competitive market, Integral believes that there has been an increase in the number of customers accepting market offers and/or switching retailers. This position is reflected in the publicly available data published by the National Electricity Market Management Company (NEMMCO) that shows a steady increase in the number of small customers that are registered with a retailer other than their local retailer, as shown in the following figure.[4]

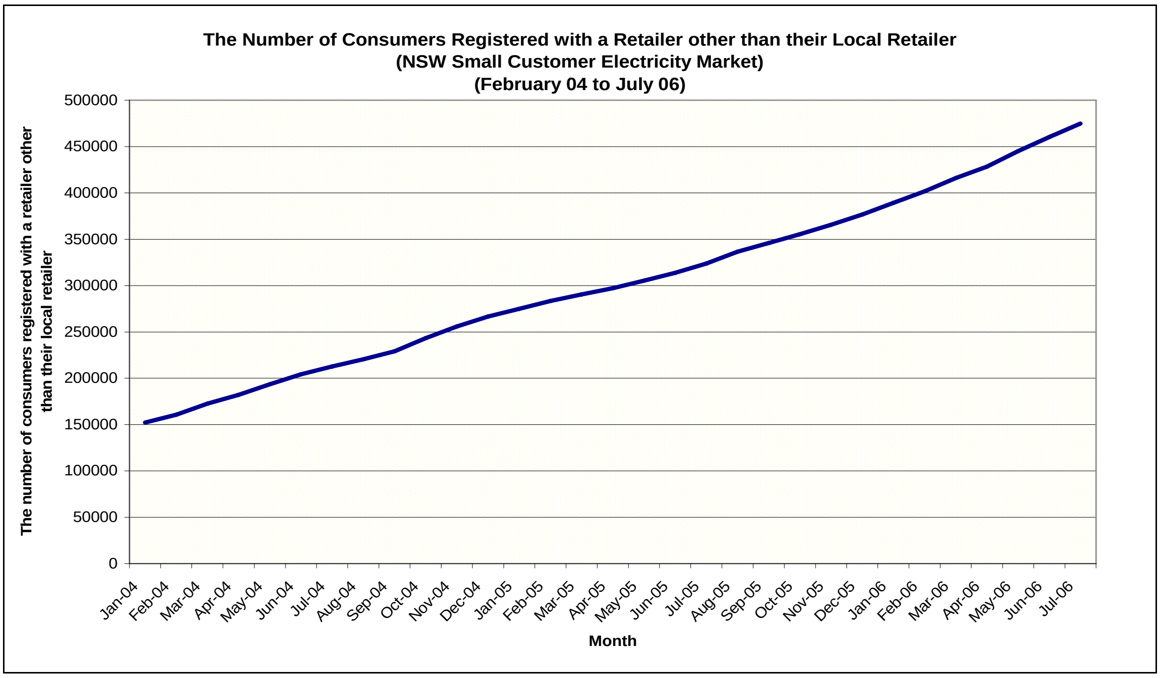

Figure 4.2 - Small customers registered with a retailer other than their local retailer

It is important to note that the above figure does not include those customers that have taken up a competitive offer with their local retailer and therefore does not reflect the full extent of competition in the NSW small customer electricity market.

A high level of competition in the NSW retail electricity market is consistent with IPART's own assessment as stated in the 2004 Retail Determination[5]:

> *The Tribunal's survey results indicate that almost 30 per cent of electricity customers have been approached to change energy supplier in the last 18 months.*

The benefits of competition are now widespread, with customers in all sections of the community now benefiting from competition to a much greater extent than in the past. While in the past, there may have been a belief that low income households are less likely to benefit from competition in the retail electricity market in NSW, based on Integral's analysis of recent trends in customer losses:

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[4] NEMMCO Website: www.nemmco.com.au/data/ret_transfer_data.htm [ACTIVET2_NMI_JUR_CLASS]

[5] IPART, NSW Electricity Regulated Retail Tariffs 2004/05 to 2006/07 Final Report and Determination, June 2004, page.33

- there appear to be very few barriers to customers accessing the benefits of the retail electricity market; and
- low income or vulnerable customers are as likely as Integral's customer base as a whole to be offered a competitive contract by another retailer.

5 Form of regulation and price constraints

5.1 Proposed form of regulation

Integral supports the Tribunal's consideration of alternative forms of retail price regulation. In developing a new form of regulation, the Tribunal must recognise that default retailers do not possess significant market power given the presence of a significant number of competing retailers and a growing awareness on the part of consumers of the competitive market.

The Tribunal has identified a range of options for the form of retail price regulation to apply over the next retail determination period in its Issues Paper[6]. These options are listed below:

- Current form of regulation;
- Weighted Average Price Cap;
- Establishing a new "safety net" tariff that customers would need to choose to be on; and
- Monitoring prices for some types of tariffs or classes of customer.

Integral engaged National Economic Research Associates (NERA) to evaluate the various regulatory options for the form of price control (FoPC) in light of the objectives of the retail review. Based on this review, the following sections summarise Integral's recommended approach to the FoPC.

This chapter discusses:

- The objectives of the current review of regulated retail tariffs, particularly those objectives that relate to the form of regulation;
- Shortcomings of the current approach to regulation of retail tariffs;
- Choices in relation to the FoPC;
- Price monitoring;
- Weighted average price cap;
- Provision for pass-through mechanisms;
- Tariff rationalisation; and
- Impact of the Determination on demand management.

[6] IPART (2006), Review of Regulated Retail Tariffs and Charges for Electricity 2007 to 2010, DP85, p.9.

5.2 Objectives for the form of regulation

In its Discussion Paper DP85, the Tribunal seeks comment on:

> *What regulatory approach best meets the objectives for the review, the pros and cons of the options, and whether there are additional broad options or variations within the options that the Tribunal should consider.*

Section 3 of the Discussion Paper DP85 notes that:

> *The terms of reference imply a range of objectives for the review, many of which are relevant to setting the form of regulation. These include:*
>
> - *reducing customers' reliance on regulated prices and encouraging competition in the retail market*
> - *ensuring that regulated retail tariffs and charges are at cost reflective levels for all small retail customers by 30 June 2010*
> - *ensuring that any price constraints allow the further rationalisation of regulated retail tariffs and movement to full cost recovery over the determination period*
> - *encouraging demand management*
> - *ensuring that regulated network charges are fully recovered*
> - *allowing for movements in regulated charges and fees for any new compulsory scheme that imposes material costs on retailers*
> - *simplifying regulated tariff structures, including removing obsolete tariffs.*

While the terms of reference imply a range of objectives for the review, Integral believes that the Tribunal should focus on ensuring that the 2007 Retail Determination achieves the following outcomes:

- Regulated retail tariffs and charges for small retail customers are at cost reflective levels by 30 June 2010;
- The rationalisation of regulated retail tariffs, particularly the removal of obsolete tariffs;
- The ability to pass through network costs; and
- The provision of a mechanism to address any new, compulsory scheme that imposes material costs on the retailer.

The achievement of regulated retail tariffs that fully reflect the cost of supply is important because of the impact of regulated retail tariffs within the competitive market. Regulated tariffs impact on the incentives for customers to take up competitive offers and, if set too low, discourage new retailers from entering the competitive market.

5.2.1 The Role of the Form of Price Control (FoPC)

The FoPC gives effect to regulatory objectives. Consequently, when there are multiple, sometimes competing, regulatory objectives, the FoPC must serve multiple objectives. As a general rule, price regulation is only desirable where a business possesses market power and can be expected to abuse that market power in the absence of price regulation. If little or no market power exists, then the rationale for price regulation is seriously weakened.

The evolution from franchise or monopoly retail service areas to full retail contestability with competitive retail markets has been facilitated by measures in a number of jurisdictions nationally and internationally. Regulators have adapted to this evolution by continually reviewing and ensuring their regulatory frameworks do not hinder this process by damaging competition or deterring entry by new retailers.

In the current context, it is possible to identify six potential criteria used to assess alternative FoPC arrangements, namely that the FoPC:

1. Protects customers from inappropriate monopoly pricing by standard retailers, should competition not be sufficiently effective;
2. Allows standard retailers to recover (efficient) costs;
3. Promotes competition as a more efficient alternative to regulation in the protection of customers from monopoly pricing;
4. Prevents excessive price shocks to individual retail customers;
5. Minimises regulatory compliance and administrative costs; and
6. Is consistent with regulatory precedent in other jurisdictions where retail competition has been successfully implemented.

5.3 Shortcomings of the current regulatory approach

The major shortcomings of the current regulatory approach are summarised below.

5.3.1 Regulatory setting of individual tariffs

The current form of regulation is overly reliant on the Tribunal correctly setting the level and structure of target tariffs. The economic cost of regulatory error in the setting of target tariffs is exacerbated under the current form of regulation by the following requirements:

- Default tariffs must be transitioned to target, subject to price constraints;
- Default tariffs must reflect the structure and level of target tariff unless the default retailer can demonstrate that it is not practicable to do so; and
- New default tariffs must be introduced at target.

In a contestable market, imposing restrictions on individual prices/revenues as well as aggregate prices/revenues dramatically increases the scope for, and potential costs of, regulatory error. This is because, in a contestable market, the constraints on the retailer are not just regulatory but also competitive. As a result, simplifications in the cost modelling that lead to under-estimates of costs for some tariffs and over-estimates for other tariffs do not cancel out. In this situation the business under-recovers on the tariff where costs have been under-estimated and is prevented by competition from over-recovering on other tariffs.

This situation creates an asymmetry of impact of regulatory error. A regulatory error that under-estimates costs for a tariff results in a windfall loss equal to the value of the under-estimate. By contrast, a regulatory error that over-estimates costs on another tariff does not result in a windfall gain of the same magnitude, as competition prevents the retailer from pricing at the allowed regulated level.

If, instead, the FoPC is only applied at the aggregate level, then simplifying regulated cost modelling assumptions is costless. So long as the aggregate level of costs is estimated accurately, the retailer can choose to recover those costs in accordance with its forecasts of actual costs. Individual tariff regulation is likely to inhibit the most efficient response to a uniform underestimate of costs by the regulator.

5.3.2 Extensive use of side constraints

The most fundamental impediment to tariff rebalancing to cost reflective levels and tariff rationalisation within the current regulatory period has been the side constraint placed on annual increases in individual tariffs. This constraint required that:

> *'the annual bill (excluding miscellaneous charges) for any customer must not increase by more than $35 excluding GST or the percentage change in CPI+5% (whichever is greater) for the same pattern and level of consumption.*[7]

IPART imposed this constraint as an additional consumer protection against 'unacceptable price increases'. This requirement was made in line with the terms of reference for the 2004 Retail Review which required IPART to consider a customer's ability to adjust to new prices as well as the need for a 'smooth transition' to full cost recovery.[8]

While this period has allowed some tariffs to transition to a more cost reflective basis, this is not true of all tariffs. As the side constraint was applied to a customer's total bill (ie, including both network and retail charges), retailers have had the potential to be constrained in their ability to rebalance tariffs. This result is because network businesses have been permitted to increase their annual tariffs by up to $30 per bill, leaving a marginal increase of only $5 for retailers (where $35 is greater than CPI + 5%).

[7] IPART, NSW Electricity Regulated Retail Tariffs 2004/05 to 2006/07 Final Report and Determination, June 2004, page 18.

[8] Letter from Minister for Energy and Utilities to IPART regarding *Review of regulated retail tariffs and charges for electricity to 2007*, 16 September 2003, page 2.

The 2004 Retail Determination also included the extensive use of side constraints. The use of side constraints effectively reduced Integral's ability to move its tariffs to cost reflective levels at the start of the current retail determination period, which is estimated to have cost Integral $12m[9] in foregone regulated retail revenue below the efficient allowance set by the Tribunal. Side constraints also impaired Integral's ability to rationalise obsolete tariffs.

In summary, the current form of retail price regulation is not appropriate given the competitive nature of the retail electricity market. Integral believes that an intrusive regulatory approach is not only unnecessary on economic grounds, it also involves a significant risk of stifling the continued development of competition. Therefore, it is important that the Tribunal adopts a new regulatory approach that allows default retailers to continue to rationalise the number of regulated retail tariffs by removing obsolete tariffs, and to achieve full cost reflectivity over a reasonable time frame.

5.4 Choices in relation to the FoPC

The first choice that must be made in relation to the FoPC is whether to impose formal price regulation or price monitoring. Formal price regulation refers to a FoPC that places specific caps on prices/revenues. Price monitoring refers to a framework within which the regulator monitors and reports on businesses' pricing conduct with the implied threat of future imposition of formal price regulation if that conduct is found to involve inappropriate exercise of market power. Price monitoring is generally only preferable where there is a competitive constraint that can be, at least in part, relied on to restrain inappropriate pricing.

The advantage of formal price regulation relative to price monitoring is that it provides regulatory certainty to the businesses involved. The disadvantage is that it does so at the cost of a higher probability of regulatory error. This is because the pricing formulae developed by the regulator can never be expected to capture and reflect all the pertinent economic circumstances over the life of the regulatory determination.

Integral believes that controls on regulated tariffs are no longer needed due to the increasing number of customers switching to competitive contracts and the development of retail competition. Price monitoring, while outside the current TOR, would be an appropriate light handed form of regulation.

5.5 Weighted average price cap

As stated above, Integral believes that a minimalist change to the existing form of regulation should be implemented. This change would see a continuation of the current Network + Retail (N+R) framework, but retail regulation would be focussed on the Retail (R) component only. A move away from pricing constraints on individual tariffs to an annual "weighted average price cap" for aggregate retail prices against an annual forecast of aggregate retail costs would provide Integral with flexibility in setting regulated retail tariffs as part of the transition from price regulation.

It is useful to identify and categorise the five key decisions that need to be made when designing a formal FoPC. These decisions are:

9 IPART (2004), NSW Electricity Regulated Retail Tariffs 2004/05 to 2006/07 Final Report and Determination, Section 4.1.3, p17.

1. The definition of what exactly should be controlled (eg, average prices per kWh (ie, revenue divided by energy), weighted average prices, revenue (ie, with no allowance for volumes));
2. The level at which the price control should be applied (eg, is it applied to individual tariffs or to average prices/revenues);
3. The use of side constraints (eg, the current CPI+5% or $35 limit on the allowed annual increase in the average bill on each tariff);
4. The inclusion of pass through mechanisms and the frequency of price control resets; and
5. The tariff quantities that should be used in the price control compliance assessment (eg, historic or forecast).

Integral has formed the following recommendations on how a formal price control should be implemented. In doing so, the sections below describe the five decisions that need to be made when designing a formal FoPC.

5.5.1 Decision 1 - What should be controlled?

The current N+R form of regulation adopted by IPART is, in effect, a form of *weighted average price cap* applied to individual tariffs, that is:

- applied at the level of each individual tariff;
- using historic quantities to test compliance; and
- with a new X-factor calibrated each year.

This may seem surprising given that the form of regulation is presented as a ‘revenue target’. Nonetheless, Integral believes it falls into the category of weighted average price cap (with “X” reset each year).

Each year IPART uses predetermined estimates of cost variables (per customer and per kWh) and historic quantities to determine the ‘retail cost’ on a specific tariff. IPART then multiplies the same quantities by proposed retail prices (net of network prices) for that specific tariff to derive an estimate of retail revenue on that tariff. IPART then approves the price increase if its estimate of revenues is less than its estimate of retail cost.

5.5.2 Decision 2 - At what level should the control be applied?

The current FoPC applies the control at the level of individual tariffs. That is, an allowable percentage increase in weighted average prices is independently derived for each tariff (in the terminology of the current FoPC this is the increase that is consistent with not breaching ‘target R’ for that tariff). Retailers do not have the flexibility to raise prices on one tariff by more than this even if it is offset by smaller than allowed increases on other tariffs.

Integral recommends that this aspect of the current FoPC be amended and that the price control be applied at the level of aggregate tariffs only. A prescriptive tariff level FoPC increases the complexity of the cost modelling the regulator must undertake. Not only must the regulator estimate total retail costs, but must also allocate those costs amongst tariffs. Even with perfect information on costs such an allocation will inevitably be arbitrary in the presence of costs that are common across tariffs (eg, billing systems, corporate overheads, corporate branding etc). In reality, the regulator will not have perfect information on costs and, even if it did at the beginning of the period, this information will quickly become outdated *during* the period.

The existence of common costs and imperfect information means that errors will be made in attributing costs to individual tariffs. In the presence of contestability, these errors will have asymmetric impacts on retailers. Under-estimates of cost for one tariff will result in a windfall loss to the regulated retailer on that tariff. By contrast, over-estimates of cost for another tariff will not result in an offsetting windfall gain because competition will impede the business from pricing above cost (even if regulation allows it).

This asymmetry means that, in order to achieve the objective of cost recovery, cost modelling must be more generous under the current FoPC than under a FoPC that is applied at the aggregate level. This is a simple reflection of the fact that where an aggregate FoPC applies, it requires fewer regulatory decisions and, as a consequence, has smaller scope for regulatory error.

Thus, use of a FoPC applied to aggregate tariffs is more likely to satisfy the criterion of “protecting customers from monopoly pricing” and the criterion of “allowing cost recovery”. The application of a FoPC at an individual tariff level, however, can be expected to satisfy the criterion of “protecting customers from monopoly pricing” but, at the expense of the criterion of “allowing cost recovery”.

The only difference between Integral’s proposed FoPC that is applied to aggregate tariffs and the current approach is that:

- the current form of price control respecifies a new X-factor each year for the weighted average increase in prices *on each tariff*; while

- the proposed form of price control respecifies a new X-factor each year for the weighted average increase in prices *across all tariffs*.

It is worth noting that Integral and its advisors are unaware of any other jurisdiction transitioning to competitive markets where prescriptive regulation is applied at the level of individual tariffs. It is also worth noting that, unlike the case for natural monopolies, the threat of competition gives standard retailers a strong incentive not to engage in allocations of aggregate costs that would be perceived as unfair by their customers (as those customers have the option of switching to other retailers).

5.5.3 Decision 3 - What side constraints, if any, should be applied?

The role of side constraints is to prevent excessive price shocks to individual consumers. NERA[10] suggests that the important question in the current context is 'what is excessive'? On one view, an increase in prices that moves those prices closer to cost, but not above-cost, is not excessive - irrespective of how large it is. On this view there is a limited rationale for side constraints, given that above-cost pricing to individual customers will expose the retailer to switching by those customers.

As discussed in chapter 4 of this submission "Current retail tariffs and competition", Integral believes that competition has been effective in both NSW and our franchise area, including the more vulnerable customer segments in our franchise area. Integral therefore recommends that side constraints on individual tariff movements be removed in recognition that competitive forces are in place to guard against pricing at levels above cost reflective levels.

If side constraints are imposed by IPART, it should be recognised that they may inhibit the achievement of cost reflectivity and, as such, their level should be calibrated to not unduly delay movements in prices to cost reflective levels.

Integral also notes that to the extent individual side constraints limit annual price adjustment on under-recovering (including obsolete) tariffs, customers on these tariffs will be insulated from attempts by retailers and network operators to employ demand management price signalling.

In addition, if side constraints are to be applied to regulated retail tariffs, it is appropriate that they only be applied to the R component of such tariffs only. In making this recommendation, Integral notes that network tariffs are separately regulated and that side constraints are already applied by IPART at the network tariff level.

5.5.4 Decision 4 - What pass through mechanisms and frequency of resets?

In the absence of pass through mechanisms retailers face an asymmetric cost of regulatory error in forecasting costs. If forecast costs are too low retailers suffer a windfall loss, but if forecast costs are too high, competition will constrain their ability to use this to obtain a windfall gain. These asymmetric costs of forecasting error can be reduced by including pass through mechanisms where costs deviate materially from forecasts.

The current FoPC has limited automatic pass through provisions that apply to changes in network tariffs. Other regulatory jurisdictions include automatic pass through mechanisms for a range of costs including energy costs. A failure to have pass through provisions for unexpectedly high energy prices was a prime cause of the Californian 'energy crisis' of 2000/01. Several US states, such as Texas, have bi-annual changes in the allowed cost of energy for regulated retailers and a similar annual arrangement exists in Ireland.

[10] See Appendix A – Form of Price Control - Integral Energy. Prepared by NERA, Page 22.

As discussed in Section 5.7.2, Integral recommends that IPART also have regard to implementing a pass through mechanism for actual energy costs. Periodic pass through of actual energy costs is consistent with the criterion of "allowing cost recovery" and also reduces the risk of regulated retail tariffs being constrained below market prices, thereby better supporting the criterion of "promoting competition as an alternative to regulation". If IPART does not implement such a mechanism then retailers should be compensated for the additional asymmetric risk they carry associated with forecasting energy prices.

In relation to the frequency of resets, the current FoPC determines a new level of allowable costs every year based on a predetermined view of *unit* costs taken at the beginning of the regulatory period combined with information on historic quantities. This amounts to a mini-determination every year where new information on units sold is examined but new information on unit costs is not. In effect, this mini-determination sets a new "X" every year. The advantage of having such 'mini-determinations' is that it better ensures that unexpected changes in quantities are not causing revenues to deviate from costs.[11] We do not see compelling reasons to alter this aspect of the current FoPC.

5.5.5 Decision 5 - What quantities should be used?

An average price FoPC must use quantities to weight individual prices. In Australia, different quantities are used as weights in price cap regulation. For retail price regulation, IPART currently uses historic and estimated tariff quantities from the preceding year to assess target revenue compliance while ESCOSA, in contrast, uses forecasts of tariff quantities for the year in which the prices are to apply. Given that the full year is not complete when the next year's prices must be approved, IPART's approach involves a mixed use of (un-audited) actual and forecast quantities. Integral believes that this approach is reasonable.

Nonetheless, Integral does see some advantage in using forecast quantities to the extent that contestability results in rapidly changing quantities. Moreover, where there is regulatory error in cost estimation, use of more up-to-date quantities to annually reset retailers' costs (and revenues) will assist in lowering the impact of such error.

In this regard, it will be preferable to use forecast tariff quantities for the year in which the tariffs are to apply. This ensures the revenue allowance is correctly calibrated to return revenues sufficient to cover the expected costs. Consequently, retail tariffs approved on the basis of forecast quantities can be expected to be more cost reflective than those which use historic quantities.

5.6 Provision for pass through mechanisms

As the point of interaction between end use customers and all upstream electricity supply chain participants, retailers are susceptible to any and all variations in electricity supply costs. While many of these costs can be reasonably foreseen,[12] there remain instances where retailers can be exposed to cost/price squeeze risks that are beyond their control. This situation is particularly the case where retailers are restricted in their price adjustments as occurs in the current approach to regulated retail tariffs.

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[11] Noting that this is only a potential issue if retailers' unit pricing is not reflective of marginal cost.

[12] For example regulated network costs and certain fixed asset costs

There is no reason why such risks should be borne by retailers unless they are compensated. In recognition of this fact, some regulators include pass through mechanisms in the retail price controls for the periodic pass through of:

- unforeseen or uncertain costs; and
- wholesale energy prices.

5.6.1 Uncertain and unforeseen costs

Integral believes that the following events should be allowed by the Tribunal as pass-through events given that they are outside Integral's direct control or influence:

- **Tax events** including, but not necessarily limited to the following:
    - changes in the way or rate at which a government imposed tax, fee, levy or charge (Relevant Tax) is calculated, or the imposition of a new tax to the extent that the change (such as the introduction of carbon tax), removal or imposition results in a change in the amount Integral is required to pay or is taken to pay (whether directly or under any contract) by way of Relevant Taxes.
- **Regulatory events** including, but not necessarily limited to the following:
    - changes to the scope, standard or risk of Integral's retail services as a result of changes to the National Electricity Rules;
    - decisions by AER, NEMMCO, the Tribunal, the NSW Government, or the courts or changes to legislation (such as environmental certificate requirements), regulation, licence conditions or other legally binding instruments that Integral is required to comply with which result in Integral incurring materially higher or lower costs associated with the retail services than it would have incurred but for that change.
    - changes to the national regulatory framework or market arrangements which impact on the regulated retail business (such as the introduction of full nodal pricing, changes to the NSW greenhouse gas abatement scheme or the Commonwealth Government's MRET scheme, or a mandated roll out of time-of-use meters).
    - changes to distribution loss factors, where these are materially higher or lower than allowed for in determined regulated retail costs.
- **Insurance events** including, but not necessarily limited to the following:
    - changes in the availability and extent of cover that result in material increases in the cost of insurance relative to the forecast included in the retail operating expense;

  - payment by Integral of a deductible premium in connection with a claim under an insurance policy;

- **Other events** including, but not necessarily limited to the following:

  - an event which is outside Integral's prudently determined risk management policies and is not insured and causes Integral to suffer material loss or damage;

  - distribution loss factors, where these are materially higher or lower than allowed for in the Determination.

In the current legislative and regulatory setting there are a number of future changes which can be expected to impact retailers during the next price control period. Many of these changes are too early in their conception to enable reasonable estimation of the likely cost impost on retailers.

As an example, the COAG in-principle agreement to roll out time-of-use meters may impose unforseen costs on retailers. These costs may take the form of additional data processing costs through to the costs of paying time-of-use network tariffs whilst being required to sustain customers on regulated tariffs where the various peak, off-peak and shoulder periods may not align. Given the uncertainties surrounding the timing and form of any roll out, and the potentially significant implications this would have on a standard retailer, Integral believes that this item should form part of any pass through arrangement.

Integral requests the Tribunal to allow for significant changes outside the retailer's control, such as those identified above, to allow for pass-through events, outside any price side constraints, when making its Determination.

A specific example of a pass through currently occurring in Australia is in the ACT, where ActewAGL is able to raise prices faster than CPI+X if it can "demonstrate"[13] that the price increase is due to:

- wholesale market conditions affecting ActewAGL's proposed benchmark price;
- the form of market arrangements adopted in the ACT market;
- NEMMCO fees and charges;
- MRETS/greenhouse levies;
- FRC customer churn rates (which give rise to FRC cost recovery different to forecast levels);
- network tariff variations; and
- other fees, taxes and imposts.

NERA advise that their understanding is that there are no side constraints applied to the tariff basket.

[13] Although rules for how these issues can be demonstrated are not well developed (at least in a public setting).

Given that there are no valid efficiency or equity reasons for providers of regulated retail tariffs to bear additional price/cost squeeze risks associated with capped prices, it is appropriate that allowance be made for the pass through of substantial unforseen or uncertain costs, such as those allowed for pass through by ActewAGL.

Such costs could be passed through on an 'as needs' basis during the standard price adjustment process. It is appropriate that IPART retain the role of reviewing such costs prior to their pass through in order to ensure that these have been efficiently incurred and are attributable only to a relevant unforeseen or uncertain event. It would also be appropriate that a framework of criteria for assessing such pass through events be consulted on and developed as part of this review.

5.6.2 Changes in energy costs

Given the substantial share of retail customer bills attributable to the wholesale price of energy, it is important that any approach to retail tariff regulation affords retailer sufficient flexibility to adjust their prices to pass on these changes to retail customers. Where this is not the case, regulated retail prices have the potential to damage the financial viability of regulated retail providers whilst also deterring competitive market entry.

Given the uncertain nature of energy prices, this flexibility may best be achieved via periodic pass through of movements in wholesale energy prices (or the drivers thereof) as adopted by various international regulators. This is consistent with the findings of the US Electric Energy Market Competition Task Force that:

> *'... design that adjusts the retail electricity price for changes in the prices of fuels used by marginal generators makes a better proxy for the market price than one that is fixed.'*[14]

The more frequent such adjustment is applied, the more closely regulated retail tariffs can be expected to approximate competitive market prices and, by implication, also approximate the actual cost of supply. One option to achieve periodic adjustment for changes in wholesale energy costs is considered in Appendix A[15].

If no pass through mechanism is introduced then retailers should be compensated for bearing the risk associated with fixed retail prices but variable energy costs (ie, bearing the risk that they will suffer a similar fate as retailers in California in 2000/01).

5.7 Tariff rationalisation

There are currently numerous obsolete regulated retail tariffs currently levied in NSW. These obsolete tariffs tend to be constrained at below cost reflective levels and indeed below IPART's own target revenue estimates. Consequently, the terms of reference for IPART's current review require that regulated retail tariffs are cost reflective and that the form of regulation adopted allows further rationalisation of regulated retail tariffs.

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[14] Electric Energy Market Competition Task Force, *Report To Congress On Competition In The Wholesale And Retail Markets For Electric Energy – Draft*, 5 June 2006, pages 91.

[15] Appendix A, NERA Economic Consulting, Form of Price Control, p27

In this regard, it would be preferable to remove the individual tariff or bill side constraints if a weighted average price cap or other form of regulation is adopted as they would afford retailers the flexibility to vary these obsolete tariffs or remove them in an efficient manner.

5.7.1 Establishing new "opt-in" regulated tariffs

IPART, in its Issues Paper[16], stated the following:

> *The Tribunal is also considering whether it could establish a number of 'basic' regulated retail tariffs that are determined at cost reflective levels from the outset of the new determination period. Under this approach, all current retail tariffs would become unregulated (that is, retailers would have discretion over whether they continue to offer the current tariffs and at what level). Customers would then be required to actively choose (or 'opt-in') to move on to the new 'basic' regulated tariff.*

The 'opt-in' regulated retail tariff approach may be an effective means of allowing retailers to abolish obsolete tariffs whilst retaining the consumer protections inherent in the default regulated retail tariffs. However, IPART would need to consider whether any legislative changes are required before an "opt-in" approach could be implemented.

Under such an approach, customers on obsolete regulated retail tariffs may be approached and offered the opportunity to take up a competitive market offer or to switch to a default regulated retail tariff. It should be noted that this 'opt-in' approach can be adopted regardless of the FoPC that is adopted, that is, an 'opt-in' approach may be used in conjunction with a weighted average price cap.

5.8 Impact on demand management

The terms of reference for IPART's current review require the Tribunal to have regard to the impact of its determination on demand management. In this regard, it is useful to examine how various forms of price control will impact retailers' ability to apply demand management price signalling, and their incentives for demand management via energy conservation measures.

In the context of retail pricing, demand management is more likely to be impeded by any side constraints that restrict retailers' ability to rebalance and restructure tariffs. Such constraints limit retailers' ability to reform their tariffs to more cost reflective structures such as time-of-use or dynamic peak pricing, either of the retail component or to pass through network tariff reform.

Therefore, consistent with the requirements of the terms of reference relating to demand management, IPART should remove any side-constraints on individual customers or individual tariffs.

Integral's proposed form of regulation of a weighted average price cap with no side-constraints would provide an incentive for retailers to undertake demand management.

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[16] Review of Regulated Retail Tariffs and Charges for Electricity 2007 to 2010, Issues Paper, July 2006, page 12.

By removing the constraints to tariff reform, retailers have the opportunity to adopt more cost-reflective structures bringing a closer alignment between retailers' marginal costs and their marginal prices, reducing retailer's risk which through competitive pressure would result in lower prices to customers.

6 Energy costs

IPART's Terms of Reference require it to ensure that regulated tariffs are at cost reflective levels for all small retail customers by 30 June 2010. In setting tariffs at cost reflective levels, IPART must consider the following.

- An allowance for electricity purchase costs based on assessed long-run marginal cost (LRMC) of electricity of a portfolio of *new entrant* generation;
- Retailers' hedging, risk management and transaction costs;
- The Net System Load Profiles (NSLPs) of each standard retailer, as well as projected future changes in those NSLPs; and
- Carbon emissions related costs.

In its previous decision, IPART set an allowance for energy purchase costs based on an estimate of the Long Run Marginal Cost (LRMC) of electricity supply. This decision reflected IPART's view that the NSW ETEF scheme provided standard retailers with suitable protection against risks associated with purchasing electricity to meet its regulated retail load from the wholesale market. IPART determined there was no requirement to incorporate allowances for hedging, risk management and transaction costs within the estimation of the overall allowance for energy purchases.[17]

In addition, in its 2004 Retail Determination, IPART decided not to calculate an energy purchase cost allowance for each NSLP. This decision was on the basis that practical problems effectively prevented the Tribunal from determining individual retailer values, due to problems with the load profile data used in the LRMC analysis.[18]

Integral has engaged LECG to assist in developing an understanding of the various aspects of the cost of energy. In particular LECG were to conduct a review of the LRMC of electricity generation and whether the concepts of LRMC and hedging are compatible, including how any relationship should be considered by IPART. LECG's report is provided at Appendix B.

6.1 Energy Purchase Cost Allowance (EPCA)

Each of the components of cost that form an allowance for energy purchase costs (henceforth the Energy Purchase Cost Allowance or EPCA[19]) properly recovered in retail tariffs are quantifiable and capable of being forecast for the review period. As a result, Integral is of the view that IPART will be able to ensure regulated tariffs are at cost reflective levels for all small retail customers by 30 June 2010.

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17 IPART final report and determination for NSW Electricity Regulated Retail Tariffs 2004/05-2006/07 dated 2004, page 39.

18 Ibid page 38.

19 As described in detail below, we use the term EPCA as shorthand to summarise: LRMC, NEMMCO, MRETS and NGACs costs, and hedging, energy risk management and transactions costs. It is the major component of retail tariffs together with network use of system charges.

The appropriate method for estimating the EPCA is the method that would be used by an efficient, prudent, new entrant retailer in establishing what is referred to as the internal or wholesale transfer price (WTP) for contract customers settled against a unique load profile. The WTP represents the 'risk free' cost of energy supply to meet a particular customer or representative[20] customer load profile. It includes the expected cost of spot market purchases, the net outcome of purchasing hedges against spot prices, and wholesale market costs, such as National Electricity Market (NEM) fees, Mandatory Renewable Energy Targets (MRETs) and the NSW Greenhouse Gas Emissions Abatement Scheme (NGAS), together with risk premiums associated with energy risk management and transaction costs.

The WTP necessarily represents a margin over external hedging and pass through costs. This represents an allowance for energy risk management and transaction costs. Further, Integral believes that there is an additional margin required in the case of a default retailer.

The figure below illustrates the proposed modified transfer price methodology.

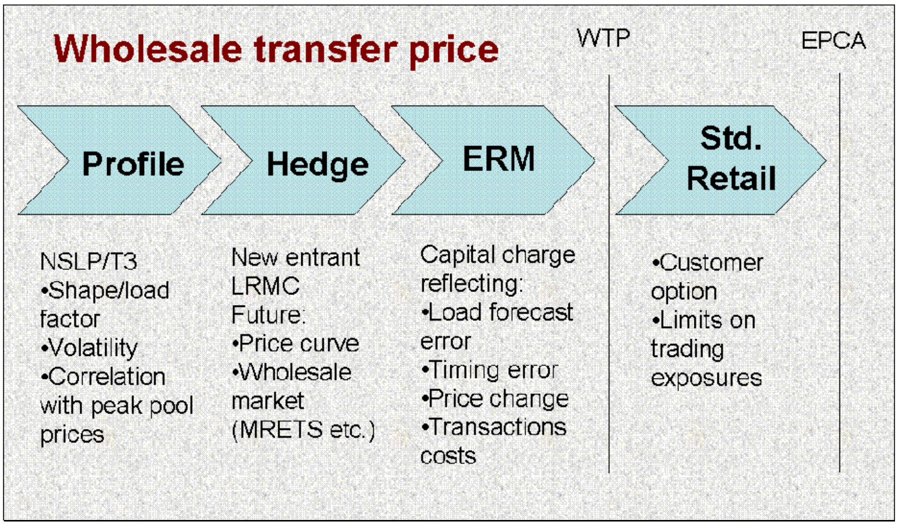

Figure 6.1 - Proposed modified transfer price methodology

There are three main determinants of the WTP for a given representative customer:

- The specific load shape of that customer, ideally for all trading intervals;
- The estimated cost of purchasing a portfolio of hedges corresponding to each trading period for the forecast NSLP in question (a proxy for which could be derived using an estimate of new entrant Long Run Marginal Cost (LRMC) for example); and
- Energy risk management and transaction costs.

[20] Representative customer is an aggregation over the total NSLP. While for large customers with time of use meters a retailer will typically assign a WTP for each customer, in the case of mass market customers, an WTP will be assigned for all customers settled against the relevant NEMMCO load profile. Thus there is just one WTP for the Integral NSLP. Retailers are likely to segment the representative customer for this NSLP in targeting potential new customers but in principle the WTP would remain. Naturally, the WTP is adjusted over time to reflect new information regarding wholesale and retail market conditions.

6.2 Customer load shape

A prudent retailer would set a different price for each of the four NSW Net System Load Profiles (NSLP) established and published by NEMMCO for the purpose of NEM settlements. This is because the level of the WTP is determined by the unique characteristics of that customer. Key variables include: the customer's peak relative to average demand throughout the year; the predictability and controllability of the customer's demand; and the extent to which the customer's peak demand coincides with system wide peak demand and hence high pool prices.

Depending on these and other factors, there will be a different WTP for each NSLP load profile calculated by NEMMCO in relation to the four NSW supply areas. A prudent retailer would certainly not set the WTP based on the average of the four NSLPs.

Data for Integral suggests the WTP for the Integral NSLP will be higher than for the other NSW NSLPs. This reflects the fact the Integral NSLP has the highest correlation with system wide peak demand and high pool price periods. Further, during these periods, there is a higher level of volatility both around demand and spot prices. Thus, load forecast and price risks associated with meeting that load are greater.

Temperature and humidity have a substantial influence on electricity consumption for air conditioning and heating. This is reflected in the fact NSW electricity consumption is highest during the hottest summer and the coolest winter periods.

Temperatures in coastal areas tend to be moderated by the sea. In the summer, this takes the form of cooling afternoon breezes. In the winter, overnight minimum temperatures are on average warmer.

The table below shows temperature differentials between Sydney[21] and Penrith for the month of December 2005.[22]

December 2005	Sydney		Penrith	
Daily over the month	**Min**	**Max**	**Min**	**Max**
Mean	18.9	28.6	17.0	32.7
Lowest	15.3	22.9	11.8	24.9
Highest	23.3	39.0	22.0	40.1

Table 6.1 - Temperature differentials December 2005

[21] Temperature data for Observatory hill.

[22] Temperature data for Penrith Lakes.

While the highest temperatures recorded during this period are similar, the mean of the highest daily temperatures for Penrith is significantly higher than for Sydney. Similarly, the difference between the mean maximum and minimum temperatures is less in Sydney than in Penrith. The shape of Integral's NSLP reflects the greater geographic concentration of Integral's NSLP and the presence of a temperature gradient between western and eastern Sydney.[23]

The relative sensitivity of Integral's NSLP to temperature is illustrated in Figure 6.2 below. This figure shows the daily load profiles for the Integral, EnergyAustralia and Country Energy NSLPs after they have been normalised to remove the effect of the different volumes associated with each NSLP.

The figure compares actual and expected load during one week in December 2005 across three NSLPs and compares these with actual and expected temperatures recorded at Bankstown by the Bureau of Meteorology (BOM). On Wednesday 7 December 2005, the temperature at Bankstown went outside the expected temperature range and recorded a peak of 39°C.

To the extent the data for this period is representative of the different NSLPs on an annual basis, it suggests Integral's load shape is characterised by a higher peak relative to annual demand (or a lower load factor). Further, it suggests the Integral NSLP may exhibit substantially higher volatility on a day-to-day basis relative to the Country Energy and EnergyAustralia NSLPs.

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[23] The data were supplied by the Commonwealth Bureau of Meteorology, http://www.nemmco.com.au/nemgeneral/040-0041.pdf

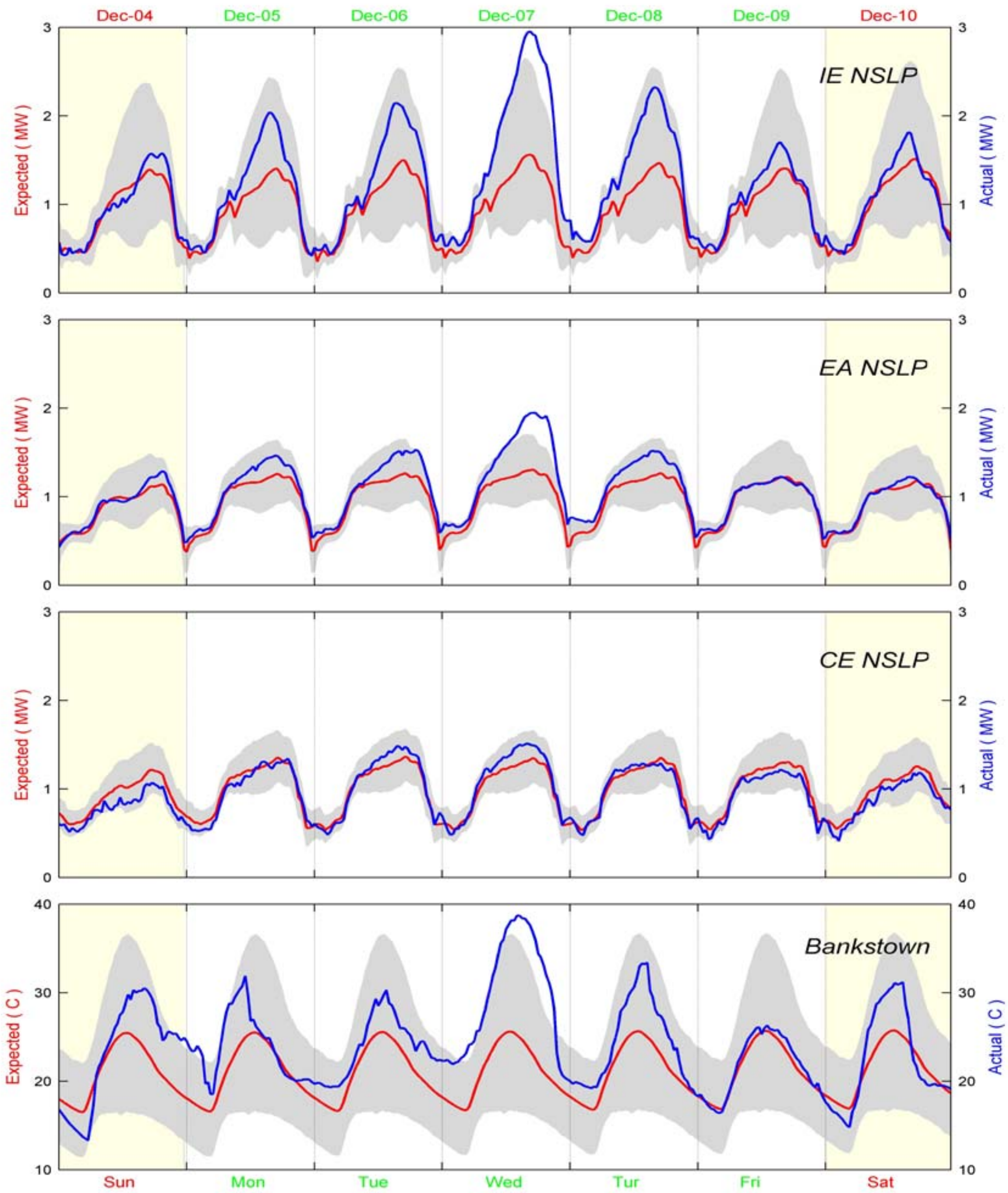

Figure 6.2 - Comparison of volatility of NSLPs for early December 2005[24]

6.3 Hedge prices

As stated, data for Integral suggests the WTP for the Integral NSLP could be expected to be higher than for the other NSW NSLPs (i.e. the cost of meeting the Integral NSLP is higher than for other standard retailers). This reflects:

24 Prepared by Integral Energy

- The shape of the Integral profile and in particular its lower load factor;
- Integral NSLP has a high correlation with system wide peak demand and high price periods; and
- There is a high level of volatility both around demand and spot prices. Thus load forecast and price risks are greater.

These factors would be reflected in differentials between overall hedge prices for the Integral NSLP relative to the other NSLPs.

The average loss factor for the Integral NSLP is 8.5%. Accordingly, an additional 8.5% should be included within the EPCA estimate to reflect the volumes that would need to be hedged.

Hedge contract prices today represent what generators will sell at given their current assessments of the market. However, if the market's perception of risks changes, hedge contract prices will change and may undergo significant step changes.

Integral recommends that an analysis of new entrant LRMC should be used to inform assumptions around future hedge prices for setting the EPCA. This is because the nature of default retail contracts requires consideration not of today's hedge prices, but for the prices that will be offered via hedges throughout the price control period.

LRMC and hedging frameworks are compatible, provided the LRMC methodology used makes realistic assumptions around the wholesale market and wholesale and hedge markets are deep and liquid. The LRMC methodology needs to reflect the imperfections inherent in the market, the fact that demand is uncertain and variable, the fact that generation capacity is added in 'lumps' and that energy risk management and transaction costs will be an addition to an estimated LRMC.

It is important to draw clear distinctions between new entrant LRMC, prevailing hedge prices, and cost reflective wholesale pricing relative to the current generation portfolio. An expert report prepared by ACIL-Tasman on 2004 NSW Government proposals for reform of the NSW-owned electricity sector concluded that continuation of a three generator structure over the period modelled would result in 'artificially high' prices relative to a five generator structure. [25] Similarly, an expert report prepared during the ACCC's consideration of AGL's part purchase of Victorian generator Loy Yang also suggested NSW baseload generators exercised market power.[26]

The method adopted for estimating LRMC must take into account the imperfections of real markets, if tariffs are to be set at cost reflective levels.

[25] See figure 1, page viii of 'Assessment of proposed energy trader scheme in NSW: Report on the effects of the proposed energy trader in NSW on the operation of the National Electricity Market and electricity consumers', dated 1 October 2004, prepared by ACIL-Tasman.

[26] 'The exercise of market power in the NEM: an analysis of price spikes in the NEM, January-June 2003', by Darryl Biggar, dated 23 April 2004.

6.4 Energy risk management and transaction costs

The potential for changes in the NSLP during the course of the 2007-10 price control period is one of the factors in support of setting the EPCA above the WTP for a corresponding contract customer. Roughly half the volume sold against the Integral NSLP will be able to be re-priced during the price control period. This option to re-price is not available with respect to the Integral regulated retail tariff business and thus there is a greater exposure to any changes to the NSLP.

The proposal to modify the standard WTP methodology, in order to reflect the higher risk profile in supplying against the standard default contract, will result in an EPCA that will be higher than the WTP for a corresponding customer on contract.

Price differentials would reflect a real differential in costs – the obligations of being a standard retailer are simply more onerous – and is therefore justifiable on the basis prices ought to reflect costs.

In calculating an appropriate EPCA for supplying customers under default retail contracts, an additional margin needs to be included over the transfer price that would be applied to the same customer on a fixed duration competitive contract settled against the NSLP. This reflects the costs to retailers of providing for the higher-level optionality granted to the customer under the default retail contract.

Depending on a range of factors including liquidity in the hedge market, commercial judgments on the part of the retailer and the risk appetite, significant trading exposures may remain which are not, or not able, to be hedged with counterparties, even by a prudent retailer. This reflects the following factors:

- It is not possible to forecast load exactly for each trading interval;
- It is not always practicable or economic to purchase hedges against all exposures;
- Liquidity or how much the market could be expected to move against a retailer that has to hedge an open position quickly;
- Changes in the value of the trading book over time depending on movements in the forward price curve (mark to market);[27] and
- Adverse cover, which refers to the size of the financial buffer an organisation may allocate in order to sustain a series of trading losses over a period.

Further aspects of residual energy trading risk may be described as transaction costs. These relate to counterparty risk and the value of outstanding offers in the market – referred to as ‘validity risk’.

Counterparty risk concerns the credit worthiness of the counterparty together with the value, quantity and duration of the financial arrangement. Validity risk (timing risk) relates to the exposure to adverse wholesale price movements between the period an offer to a customer is made, and when it is accepted, and corresponding hedging arrangements put in place.

[27] See Integral’s Annual Report to 30 June 2005, Note 27d to the Financial Statements.

A prudent retailer will carefully manage the exposure to these risks. An example would be a prohibition on dealing with counterparties whose credit rating is below a minimum threshold in the absence of a bank guarantee. In the case of validity risk, it may be possible to make the offer conditional on there being no material change in wholesale market conditions (or to include conditions which deal with adjustments to prices if certain wholesale market conditions materialise).

By their nature, ERM risks cannot be recovered through adjusting the retailer's estimate of its weighted average cost of capital (WACC). Rather, they must be recovered through an appropriate charge on the capital allocated to ERM and transaction costs. In the case of NSW energy corporations, NSW Treasury has issued instructions that capital must be explicitly allocated to energy risk management and transaction risk exposures.[28]

Analytically, the portion of the net retail margin corresponding to ERM and transaction costs should be treated as within the EPCA. However, because ERM and transactions costs are typically captured in the form of a capital charge, they do not form part of a retailer's ordinary expenditure. Rather, they are recovered from a mark up on each unit of energy sold and thus recovered from margins. Accordingly, the quantification of ERM and transactions costs needs to be cross referenced with the estimation of the appropriate level of the net margin.

6.5 EPCA adjustments for 2007 Retail Review

The figure below illustrates the application of the proposed EPCA methodology described above to the overall build up of retailer costs.

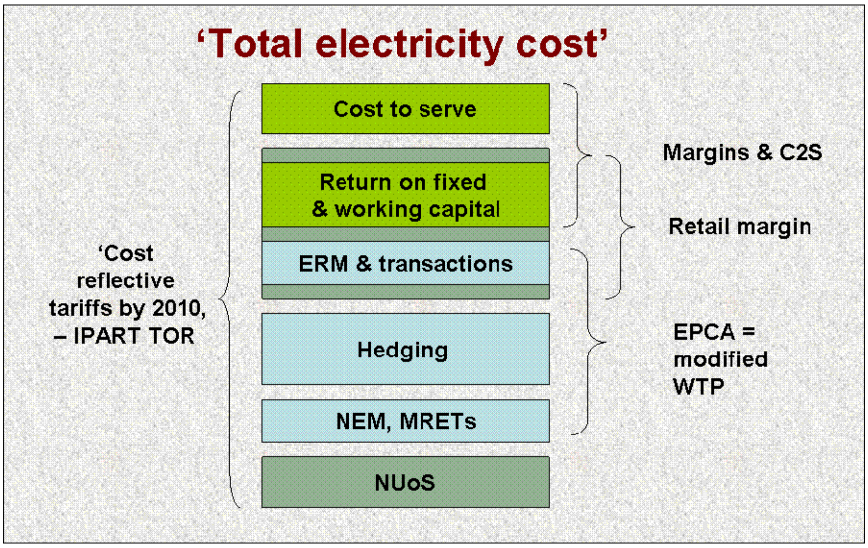

Figure 6.3 - Build up of retailer costs

The EPCA includes energy risk management (ERM) and transaction costs, which are typically recovered from a retailer's overall retail margin, reflecting a return on the capital that is required to be allocated to ERM and transaction costs.

[28] See NSW Office of Financial Management: Policy and Guidelines Paper TPP 99-5, dated October 1999.

There are a number of factors that suggest an increase in the EPCA will be required compared to that identified in the previous determination. This reflects the shortfall in the 2004-2007 determination given the changes in the current TOR to incorporate energy risk management and transaction costs; the Integral NSLP; and the fact the previous LRMC calculation made some very conservative assumptions. Importantly, the previous LRMC analysis did not adequately reflect the imperfections in the market, and dismissed the need for energy risk management and transaction costs to be added to the underlying LRMC estimate.

In terms of an alternate methodology, Integral recommends that the following key components are reflected in the analysis of LRMC, to ensure the energy purchase component is cost reflective:

- Any changes to the key cost parameters that have arisen since the previous determination (i.e. how new entrant generator energy costs have changed);
- Modelling of capacity factors through looking forward and modelling new entry (of generation capacity), as it would happen in reality. This means considering how and when planned/committed generation would enter the market, given its lumpy nature. It also means considering the other factors affecting capacity factors such as how long it is assumed that the various technologies remain competitive, as well as the competitive response expected as a result of new entry;
- A reflection of the true new entrant supply curve when considering new entrant generation i.e. it must account for key features of generation in a realistic market setting including the fact that generation enters (and exits) from the supply curve in large increments, rather than being infinitely divisible;
- A recognition and incorporation of the demand to be met being uncertain and volatile. Variations in demand should be incorporated in the model to represent the potential uncertainty in the level of demand to be met;
- A subsequent demand/supply match which reflects the fact that generators will need to allow for this uncertainty and volatility, and that market prices will reflect the risk that generators must absorb if they are to maintain a presence in the market. The capacity factors ascribed to new entrant plant should reflect this uncertainty, and should reinforce the likelihood that demand will not exactly match supply at all points along the spectrum;
- Hedge costs, transaction costs and risk are included as additional costs to a retailer (i.e. covered as ERM and transaction costs as described above) looking to secure capacity to cover a regulated retail load. As noted earlier, an efficient retailer will look to manage risk surrounding their purchases by internally hedging or buying some output from the spot market for example. These costs need to be allowed for to help reflect the full real cost to retailers of purchasing energy to meet their regulated retail load; and
- Losses must be taken into account, as the amount paid by the retailer must compensate for energy lost in transmission and distribution.

Without the inclusion of these key components in the IPART analysis of LRMC and the total realistic energy purchase costs for retailers in NSW, Integral believes that the final regulated retail tariffs set will not be cost reflective.

6.6 ETEF

With the expiration of vesting contracts at the end of 2000, the Government considered ways to manage what it saw as risks for retailers associated with purchasing wholesale electricity for small retail customers who elect to purchase electricity under standard terms and conditions; including regulated retail tariffs.[29] The preferred option, introduced on 1 January 2001, was the Electricity Tariff Equalisation Fund (ETEF). In introducing the ETEF, the Government sought to offer regulatory price protection to retailers (for their regulated retail load), while also seeking to limit the exposure of the Government to any unacceptable financial risk.[30]

It did so by requiring that when pool (i.e. spot) prices were lower than a regulated energy cost (or REC), regulated retailers (or standard retail suppliers as denoted by the NSW Treasury) were required to pay money into the ETEF. When pool prices exceeded the energy cost component in the regulated tariff, the ETEF would make payments to standard retail suppliers to enable them to purchase wholesale electricity for regulated customers and still earn a regulated margin.[31] If there should be a shortfall in the ETEF, Government owned generators in NSW would be required to make payments into ETEF to fund the shortfall.

By using the pool price as a comparator for the REC, the ETEF system effectively assumed that without ETEF, retailers would be meeting their regulated retail load using pool purchases, or from other mechanisms with prices analogous to those present in the pool.

The REC was based on the long run marginal cost of the generation system, as determined by IPART as part of its regulated retail tariff determinations. Because of the variability in tariffs between different customers, the REC used in the ETEF varies for each standard retailer. In determining the REC for each standard retailer, the NSW Treasury deduces a value that:[32]

- Is derived from the weighted average of the existing tariffs currently in use by the retailer;
- Is sculpted by NEM peak and off-peak times; and
- May be annually updated to reflect changes in the distribution of tariffs and the volume of electricity sales related to those tariffs.

In April 2006, the NSW Government finalised new ETEF pricing rules to provide for a phase out of ETEF between September 2008 and June 2010[33].

[29] "Electricity Tariff Equalisation Fund: Information Paper", Office of Financial Management, New South Wales Treasury, December 2000.

[30] ibid, p.1.

[31] ibid, p.2.

[32] ibid. p.6.

[33] See Electricity Tariff Equalisation Fund: Payment Rules Version 2, dated April 2006

The removal of the ETEF mechanism features in IPART's Issues paper which recognises the need to consider potential flow-on impacts that its removal may have. The paper notes the need to consider any effects on hedging, risk management and transaction costs and forecasting risk that may arise in ETEF's absence.

Integral's proposed method for estimating the EPCA is based on replicating the full energy purchase costs that would be faced by a stand-alone new entrant retailer. Reflecting IPART's Terms of Reference, the proposed method includes an allowance for transaction costs and energy risk management risks created by competitive purchasing from generators. The implication is there would be no adjustments to the EPCA to reflect the gradual removal of ETEF.

6.7 Other costs

The 2007 Review also requires the consideration of other costs that a retailer will face in meeting its regulated retail load. These costs include:

- Generator NEM fees;
- NUoS charges;
- Cost of compliance with 'green' energy options (MRET and GGAS); and
- Retailer NEM charges and ancillary charges.

An allowance for generator NEM fees and NUoS charges is likely to be best dealt with as an explicit addition to a LRMC estimate. In this manner, they would essentially be treated as 'pass through' items, as they are unavoidable. In the previous determination, an allowance of $1.00/MWh was included for generator NEM fees and ancillary charges. The treatment of ancillary charges is also likely to be best dealt with via an assumed addition to an LRMC estimate.

The cost of compliance with 'green' energy options, and the retailer NEM charges however, are more endogenous in nature. In terms of the 'green' energy options, both the Commonwealth Mandatory Renewable Energy Target (MRET) and NSW Greenhouse Gas Abatement Scheme (GGAS) obligations need to be considered. In the previous determination, they were dealt with via an addition of $1/MWh and $2/MWh to the LRMC, for the MRET and GGAS schemes respectively.

The need to purchase energy from renewable sources (MRET) and the need to meet greenhouse gas reductions targets may, however, influence the portfolio of energy purchased by a retailer in meeting its regulated retail load. The retailer may purchase a higher/lower proportion of energy needs from a particular generator to satisfy MRET and GGAS requirements, and this may differ from purchases in the absence of such schemes. For this reason, it is suggested that when the LRMC analysis in conducted that the potential for altered energy purchases because of MRET and GGAS is at least considered as a possible endogenous effect, rather than an exogenous and explicit addition to the LRMC estimate.

The retailer NEM charges are based on a retailer's energy purchases (on a MWh basis) and hence should be calculated directly (essentially derived) from the LRMC analysis, which will identify energy purchase requirements for each retailer.

6.7.1 Proposed green energy licence condition

The NSW Department of Energy and Utilities released a preliminary issues paper in January 2006 with detailed proposals for a requirement for all licensed NSW retailers to offer a 10% Green Power Scheme.

The WTP methodology identified earlier would be applied in estimating the incremental cost of meeting the additional energy purchasing costs associated with the eventual green energy licence condition. In particular, judgments would need to be made around the costs of purchasing or creating green energy products and the possibility of price volatility because of supply-demand imbalances. A higher probability of price volatility may be expected given the relative scale of the purchases that would be required under the scheme. Further, a key design feature of the scheme, the right for customers to opt out any time, introduces significant risk exposures that would need to be managed.

It is understood the incremental cost of energy purchases in order to meet the requirements of the scheme would be above the EPCA. Further, it is also assumed this incremental cost could be determined by retailers on a cost reflective basis. Accordingly, our understanding is the cost of purchasing green energy products over the cost of MRETs and NGACs would be excluded from the estimation of the EPCA for the purposes of setting standard retail tariff and that Integral would offer this product as a premium product above the regulated retail tariffs.

6.8 Considerations for LRMC going forward – ‘keeping up’

Another component of the forward looking nature of the suggested approach for producing cost reflective energy purchase costs involves considering potential price/cost pressures that are likely to affect LRMC for new entrant plant. Failing to take account of these potential price/cost pressures would mean that the regulated retail tariff would not be cost reflective for the duration of the price control period.

A number of key areas where cost/price pressure could be felt in the period to be covered by the 2007 review have been identified:

- **Natural gas prices** – the world market for natural gas is becoming deeper and more diverse. As it develops, prices faced by potential new entrant generators in Australia will be increasingly influenced by international natural gas prices, as well as by domestic resource availability.

- **Coal prices** – similar to natural gas prices, the growth in coal trade internationally will mean that prices will be increasingly influenced by the opportunity cost of selling domestically i.e. selling it internationally.

- **Capital costs** – international demand for capital equipment required for new entrant electricity generation will also be an important consideration. For example, existing estimates of $/kW installed costs for coal, Combined Cycle Gas Turbine and Open Cycle Gas Turbine plant could be different to those currently assumed, because of growth in world demand for this equipment. Upward pressure on capital costs can be observed in recent reports of substantial increases in the costs of large energy infrastructure projects, for example the NW Shelf expansion and other large energy related projects in WA and Queensland[34].

- **Exchange rate impacts** – changes in the value of the Australian dollar can also influence the cost of capital equipment for generation, and hence potentially the cost of output from new entrant generation.

- **Emissions charges** – there has been a large amount of publicity recently concerning the potential impacts of options for dealing with greenhouse gas emissions. It is likely that any form of charge relating to emissions of carbon (one possible option for targeting carbon emissions considered in other jurisdictions), should it be introduced, would have a material impact on the cost of new entrant generation from fossil fuels.

Potential changes to these key input parameters used in estimating new entrant LRMC should be considered, to ensure that energy purchase cost estimates are cost reflective. Generators (existing and new) will be considering the potential impact of variability in these factors in their pricing decisions, and hence there is the prospect that this risk may pass through to the energy purchase cost for retailers.

[34] See for example a current report on the increased costs associated with the NW shelf expansion: http://www.smh.com.au/news/business/soaring-costs-hit-shelf-expansion/2006/09/05/1157222131451.html

7 Retail margin

7.1 What is the retail margin intended to cover?

The Minister's Terms of Reference for the 2007 Retail Review require Integral to develop its position on the appropriate allowance for the retail margin for a "mass market new entrant". This chapter outlines Integral's recommended approach to calculating an appropriate margin, commensurate with the underlying risks, to be included in regulated retail tariffs.

As a general principle, the non-energy and non-network costs faced by retailers can either be directly reflected as a line item in the retail costs estimated for the business, or an allowance can be made to cover these costs in the retail margin. The retail margin should compensate retailers for costs not compensated for elsewhere in the framework (including the cost of systemic and asymmetric risks).

The approach to estimating the retail margin adopted by regulators in Australia is largely one of "benchmarking" against the margin decisions of other regulators, adjusting for specific factors present in the particular circumstances of each review. In undertaking such a benchmarking exercise, it is important to be clear on exactly what is covered by the retail margin in order to be able to determine the relevant comparability between the margins that have been allowed in other jurisdictions.

In addition, being clear on what costs are intended to be compensated via the retail margin means that it is possible, at least in the case of the major cost items, to undertake quantification of the appropriate size of the retail margin, independent from a consideration of what has been allowed by other regulators.

There are no 'hard and fast' rules as to whether a particular cost should be allocated to the retail margin, retail costs or to energy costs. Regulators in Australia have differed in the approach they have adopted. The differential treatment of the margin elements is summarised in section 7.4 of this chapter.

An important first step in determining the appropriate retail margin for a new entrant is therefore to consider, within the overall framework adopted for the retail review, which costs are intended to be compensated for via the margin and which are allowed for in other aspects of the determination (i.e. retail operating costs or energy costs). It is important that all relevant costs (including the cost of risk) are reflected in the overall cost benchmark derived for retail tariffs.

The potential costs, which may be compensated for via the retail margin, are further considered in the following sections.

Integral engaged National Economic Research Associates (NERA) to prepare a report on estimating the mass market new entrant retail margin. Their report is provided at Appendix C.

7.2 Potential costs to be recovered by the retail margin

IPART's 2004 determination stated that its estimate of the retail margin was intended to compensate retailers for capital investments and the risks they assume (where those risks are not compensated for in other aspects of the regulated tariff), such as those associated with power trading, competition from substitutes and customer default: [35]

> *"The net profit margin represents the reward to investors for committing capital to a business. The level of profit margin is influenced by the level of risk associated with energy purchasing costs, customer default and bad debt, and competition from electricity substitutes."*

The general classes of costs which may be covered by the retail margin include:

1. Return on capital, including:
   - physical assets;
   - working capital.
2. Return of capital (depreciation).
3. Amortisation of intangible assets.
4. Interest and taxes[36].
5. Compensation for asymmetric risks:
   - residual risk associated with energy purchases;
   - other asymmetric risks, e.g. the risk of billing systems failures.
6. "Headroom".

7.3 Additional costs incurred by a mass market new entrant

As noted in the introduction, the Minister's Terms of Reference require IPART in making its investigation and report on the setting of tariffs for small retail customers for the 2007 Review to consider the appropriate 'mass market new entrant retail margin.'

The Terms of Reference reflect a significant departure from the approach that IPART was previously required to adopt, which was to estimate the retail costs and retail margin appropriate for a standard retailer. The margin can be expected to be higher for a new entrant than for the incumbent retailer as a result of two factors:

- The need to explicitly value the customers of the retail business, and to allow for a return on and amortisation of this value in the margin;[37] and

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[35] IPART 2004, p42

[36] In general, compensation for interest and taxes will occur via the allowed return on capital. However, compensation for risks will also be subject to tax, and this should be recognised in the level of the overall margin.

- The appropriate return on tangible assets (eg, billing systems, B2B costs) included in the margin should be based on the costs incurred by a new entrant, rather than on the historic cost of the incumbent's physical assets.

IPART notes in its Issues Paper that new entrant costs are likely to include additional costs, such as customer acquisition and billing systems, and may lead to a higher overall cost than was included in the 2004 Retail Determination. [38]

The following three categories of additional costs would be incurred by a new entrant:

1. The costs associated with customer acquisition (which equates to the implied valuation of Integral Energy's current customer base, ie, a valuation of intangible assets);
2. The costs associated with establishing the physical infrastructure necessary to operate a retail business (eg, billing systems, call centres). These costs are likely to be higher for a new entrant than for the existing incumbent retailer; and
3. Cost differences in retail costs which a new entrant would face compared to the incumbent business, given that the incumbents in NSW are government-owned and also own a distribution network business.

7.4 Elements of the Margin

The treatment in the previous regulatory decisions of the various cost elements that could potentially be covered by the retail margin is discussed in more detail below. In some cases, it is not obvious whether certain costs have been included in the margin.

7.4.1 Return on capital (tangible assets)

IPART's view as expressed in its 2004 Retail Determination is that the retail margin "represents the reward to investors for committing capital to a business."[39] The margin allowed by IPART therefore was intended to provide a return on the capital invested in the physical assets required to operate a standard retail electricity business.

Similarly, a return on capital is included in the margin in Victoria and in SA. ESCOSA also carried out a return on investment analysis, applying a WACC of 8% - 10% to capital assets (including physical assets), to compare with its benchmark margin analysis.

[37] The alternative would be to allow for the return on and amortisation of the value of customers as part of retail costs.

[38] IPART Issues Paper, p. 2.

[39] IPART 2004, p42

7.4.2 Depreciation

In its 2004 Retail Determination, IPART allowed for depreciation of retail assets in the calculation of operating costs,[40] rather than in the retail margin.

Depreciation is intended to be compensated for via the margin in SA. ESCOSA also made an explicit allowance for depreciation as part of its quantitative return on investment calculation. NERA was not able to determine whether depreciation is included in the calculation of the margin in Victoria, or within operating costs. The Victorian Government engaged CRA Asia Pacific to review the costs of supplying standard domestic and small business customers for Victorian gas and electricity retailers. The report by CRA does not make specific reference to depreciation. As a result it is not possible to determine whether depreciation is included in the calculation of the margin in Victoria or within operating costs.

7.4.3 Return on capital and amortisation (intangible assets)

For a retail business, its intangible assets (i.e., customers) are of much greater significance than its physical assets. Customer acquisition costs, therefore, are an important consideration for the 2007 Retail Review and in particular in establishing the costs that a mass market new entrant would face to acquire “regulated” customers. While the preferred methodology to incorporate customer acquisition costs is through the retail margin, another option is that these costs are be included as a “line item” in retail operating costs. Integral believes it important to ensure:

- Customer acquisition costs are recognised in IPART’s framework; and
- These costs are not “double counted”.

In order to reach an efficient scale a new entrant must invest in acquiring customers. This investment can take a number of different forms including advertising, doorknocking, sponsorship or direct purchase of customer bases from incumbents. Once customers are acquired (i.e., once the new entrant is an incumbent) a return on those investments is required. Moreover, the business will also require a return of (amortisation of) those investments over the typical life of a customer so acquired. With the exception of network and energy costs, customer acquisition costs are likely to be the most significant cost faced by retailers.

One of the most readily available estimates of customer acquisition costs are the actual amounts paid for the direct purchase of retail energy customer bases. The amount a new entrant is willing to pay for customers in such transactions will reflect the cost to them of acquiring those customers by other means. That is, retail company A will only buy customers from retail company B if the price is lower than company A’s own assessment of the costs of acquiring the same number of customers by other means (eg doorknocking).

[40] IPART, 2004 Determination, p9.

NERA undertook an analysis of the energy retail customer acquisition costs observable in the Australian and International energy and telephony markets and the details of this analysis are provided in Appendix C. The average of all energy retail customer acquisition cost observations reported in Appendix C is $524 per customer. Integral believes that this is the most reliable estimate of the cost of acquiring retail energy customers through direct purchase. A summary of the acquisition costs analysed is provided in the following table.

Acquisition cost measure	Mean acquisition cost (AUD $ per customer)
Australian energy retail	618
All industries (Aust & International)	540
All energy retail (Aust & International)	524
Foreign energy retail	465

Table 7.1 - Summary of customer acquisition costs

IPART does not appear to have made any explicit allowance in the margin for a return on intangible assets or amortisation of those assets in its 2004 Retail Determination. In its earlier 2000 Retail Determination, IPART considered marketing costs, and decided that it was inappropriate to include these in the tariff for a regulated service, as marketing was not relevant for such a service.[41]

7.4.4 Return on capital (working capital)

Electricity retailers generally recover their revenues between at least 1 and 3 months in arrears reflecting the fact that customers are on either monthly or quarterly billing cycles. In general, retailers' costs are paid on much shorter terms than this (eg, energy and network costs).

This means retailers must finance substantial working capital. Consequently, it is appropriate to provide a working capital allowance to cover this (as per IPART's most recent network decision).

Integral considers that it is appropriate that working capital be included in the retail margin, and we note that it is not entirely clear from the 2004 Retail Determination whether or not working capital was included in the allowed 2% retail margin.

Working capital is included in the margin in both SA and Victoria.

[41] IPART, Dec 2000, Regulated retail prices for electricity to 2004, p51.

7.4.5 Interest and taxes

Interest and taxes are explicitly allowed for as part of the margin in SA. They are not explicitly provided for in NSW or Victoria, however, we assume these components are also included in the margin in these jurisdictions as part of the return on capital.

7.4.6 Energy purchase risk

When there is no regulatory asset base to act as a 'buffer' capable of absorbing shocks and preventing insolvency, it becomes acutely important that compensation for asymmetric risks be explicitly included in the regulatory determination. The absence of a regulatory asset base in electricity retailing poses some potential problems. In order to attract equity and debt finance an electricity retailer would have to provide compensation to investors for these risks.

Moreover, any investor in a new entrant dealing with complex hedging products will retain some residual risks.

In its 2004 Retail Determination, IPART saw energy purchase risk as part of the margin.[42] However, IPART took the view at the time that most energy purchase price risk which would otherwise have been faced by NSW retailers was eliminated by the ETEF. Consequently, there was no need to provide compensation for this risk in the retail margin,[43] since it was "not appropriate to provide an allowance to standard retailers for costs that they will not incur over the course of the determination." [44]

The phase out of ETEF during the 2007-10 regulatory period, that IPART must consider as part of its Terms of Reference, suggests that IPART will now need to provide an allowance for energy purchase risk as part of the retail margin.

7.4.7 Risk of customer default

In its 2004 Retail Determination, IPART took the view that an allowance for the risk of customer default should be compensated for via the retail margin. IPART noted that there had been only limited switching in 2004, and considered that the 1.5% to 2.5% range for the retail profit margin provided sufficient compensation to retail suppliers for this risk.[45]

However, IPART observed that "[a]s full retail competition (FRC) progresses, it seems reasonable to expect that the regulated customer base would become more 'risky'." [46] IPART expected the riskiness of the default customer base to increase over the 2004-2007 period. As outlined in Chapter 4 of this submission, Integral believes that considerable competition already exists in NSW, suggesting that an allowance in the margin for the risk of customer default is now required.

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[42] IPART, 2004 determination, p42

[43] IPART, 2004 determination, p43.

[44] IPART, 2004 determination, p43.

[45] IPART, 2004 determination, p44.

[46] IPART, 2004 determination, p44.

7.4.8 Uncertainty of cost estimates

In Victoria, CRA made an additional allowance in the retail margin for the increased uncertainty of operating cost estimates over the 2005 to 2007 period (as opposed to estimates for a single year, 2004). Further, the benchmark range established for retail operating costs in Victoria appears conservative, especially compared to the approach adopted in NSW in 2004.[47]

Such an allowance was not explicitly provided for in NSW or SA.

7.4.9 Competition from energy substitutes

In 2004, IPART considered that the margin would include an allowance for "competition from energy substitutes".

Such an allowance was not explicitly provided for in Victoria or SA.

7.4.10 Headroom

In some jurisdictions 'headroom' has been included in estimating the retail margin. This is intended to be an additional element built into tariffs to ensure that regulated retail tariffs provide sufficient scope for both the incumbent retailers and for other retailers (including new entrants) to offer attractive competitive tariffs to end-users. Where regulated tariffs are set at (or even potentially below) actual cost levels, there will be limited opportunity for other retailers to offer competitive tariffs, which can affect the development of the competitive market.

In its 2004 Retail Determination, IPART considered the inclusion of headroom as an additional allowance in the margin for the purposes of promoting competition. It took the view, however, that it was not desirable from an economic efficiency or equity perspective to allow headroom in the retail margin; rather, tariffs were to reflect efficient costs. [48]

This stance was also reflected in the approach taken to setting a range for recoverable operating costs; that is, there was no explicit allowance for headroom in operating costs (or in the wholesale energy cost estimate). While there was no explicit efficiency adjustment made to actual costs in the 2004 Retail Determination, in calculating the range, 'outlying retailers', which had costs significantly above most other retailers, were excluded. This decision had the effect of reducing the allowance for retail operating costs (i.e., the reverse impact to that which would arise from an allowance for headroom).

The approach in Victoria appears to have been the opposite. The Victorian Government's determinations for both electricity and gas retailers in Victoria for the period 2004-2007 explicitly included headroom in determining the allowed margin.

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[47] In particular, the operating cost allowance in Victoria was increased from $65 per customer to $90 per customer in 2003, on the basis that there was uncertainty over the correct level, and $90 per customer was closer to the retailers' own assessment of operating costs. In contrast, the 2004 Retail Determination resulted in an allowance of $70, chosen from an operating cost range of $50-80 per customer, which was derived by explicitly excluding higher cost 'outliers.'

[48] 2004 Retail Determination, p24.

7.5 Margin Decisions in Other Jurisdictions

This section considers the most recent retail margin decisions in NSW, Victoria and South Australia, for both the electricity and gas retail sectors as these represent the three most recent regulatory decisions on the retail margin.[49]

This comparison focuses in particular on the coverage of the retail margin in each of the decisions, paying particular regard to the costs and risks that are intended to be covered by those margins in each case and the comparability with the costs and risks faced by a mass market new entrant in Integral's area.

The main point emerging from the analysis is that there has been little uniformity in regulators' views with regard to the coverage of the margin in each jurisdiction. Margins in other jurisdictions include some costs which have instead been included in operating costs in NSW (e.g., depreciation). They also include some factors not taken into account anywhere in regulated retail tariffs in NSW (e.g., intangible assets in SA; 'headroom' in Victoria). In many cases, the question of whether certain factors have been incorporated in the assumed margin is at best opaque, and has become more so over time.

The following table presents a comparison of the coverage of the allowed retail margins for electricity and gas in NSW, South Australia and Victoria. In particular it summarises the inclusion or exclusion of each of the classes of costs which may be covered by the retail margin. A "tick" indicates that the element is included in the margin; a "cross" indicates that it is not included. Where a cell has been left blank this is because it is not clear from the relevant determination whether or not the factor has been included in the retail margin.

[49] The ICRC considered the issue of the retail margin as part of its April 2006 report into retail prices for non-contestable electricity customers. The ICRC has recommended that the regulated tariff be discontinued from 1 July 2007. Its consideration of an appropriate retail margin to include within regulated tariffs before this date relied on a comparison of the allowed $/customer margins allowed in NSW and Victoria.

	Electricity			Gas		
	IPART 2004 –2007	**ESCOSA** 2005 – 2008	**Vic**2004 – 2007	**IPART** 2004 – 2007	**ESCOSA** 2005– 2008	**Vic** 2004 – 2007
Margin	**2%**	**4-6.5%**	**5-8%+ (CRA) 7-9% (Govt)**	**2-3% (NERA)**	**3.4-4.3%**	**2-3%+ (CRA)**
Return on capital (physical assets)	✓	✓	✓	✓	✓	✓
Depreciation	× (incl. in op costs)	✓			✓	
Return on capital (intangible assets)		✓			✓	
Amortisation		✓			✓	
Return on capital (working capital)	× (not clear if incl. in op costs)	✓	✓		✓	✓
Interest and taxes		✓			✓	
Energy purchase risk	×[1]	×[2] (incl. in energy costs)	✓[3]	×	×	
Uncertainty of operating cost estimates			✓			✓
Riskiness of customer base	✓	?[4]				
Competition from energy substitutes	✓					
Headroom	×	×	✓	×	×	✓

Table 7.2 – Comparison of coverage of retail margins between jurisdictions

1 *IPART saw energy purchase risk as part of the margin, but gave no additional return for it, due to the ETEF.*

2 *ESCOSA 2005 determination contains no explicit discussion of energy risk in the margin analysis, although its earlier 2002 determination did reference the peakiness of the SA market as contributing to the choice of the margin estimate.*

3 *CRA: energy purchase risk is included in energy costs, but allowance also made in the margin for remaining uncertainties.*

4 *ESCOSA 2005 determination contains no explicit discussion of cost of risk associated with customer default; 2002 determination did reference the risks faced by AGL as the retailer of last resort.*

In all three jurisdictions, retail margins have been established by having regard to the margins allowed by other regulators. However in ESCOSA's recent decision this analysis was supplemented by a calculation of the required return on, and of, investment.

Given the differences in coverage of the retail margin between jurisdictions, and the lack of clarity as to which costs have been considered in setting the margin, this suggests that there would be considerable merit in adopting an alternative approach to determining the retail margin, other than 'by comparison.' In the context of the move to a single national regulator there would be considerable advantage in having a uniform national approach where this was practical.

Integral believes that, where practicable, the Tribunal should support the move to a more nationally consistent approach in establishing an appropriate margin for regulated retail tariffs.

7.6 Implications for the Retail Margin for NSW for 2007-2010

The table below highlights those factors that Integral considers should be covered within the retail margin estimated for the NSW incumbent retail businesses for the 2007-2010 period, and compares this with the factors that were covered by the 2004 determination.

The proposed allocation is largely based on providing a greater degree of comparability and uniformity with the approaches in other jurisdictions, and on the similar treatment of the return on and of capital between physical and intangible assets.

Items shaded are those which imply that the margin for 2007-2010 should be *above* that for 2004, based on an assessment of both the factors that have changed since IPART's previous determination and also those cost elements which were not previously covered by the estimated margin. Darker shading indicates factors which *could* be included in the margin (or alternatively, could be allowed for in establishing retail operating costs).

	IPART 2004 – 2007	Proposal 2007-2010
Return on capital (tangible assets)	✓	✓ New entrant systems costs above Integral's historic costs
Depreciation	×	✓ Include within margin rather than operating costs
Return on capital (intangible assets)		✓ Customer acquisition costs
Amortisation		✓ Customer acquisition costs
Return on capital (working capital)	×	✓ Include within margin rather than operating costs. May have been omitted last time
Interest, Taxes	✓	✓
Energy purchase risk	×	✓ Phasing out of ETEF. Hedging costs captured in energy cost estimates – but residual risk compensated by margin
Uncertainty of cost estimates	×	**?**
Riskiness of default customer base	✓	✓
Competition from energy substitutes	✓	✓
Headroom	×	**?**

Table 7.3 – Costs to be compensated for via the retail margin 2007-2010

The comparative analysis of different regulatory decisions presented in this chapter also highlights the difficulties of this approach to determining an appropriate margin. The decisions of previous regulators have differed in terms of the costs which are intended to be covered by the margin, and the regulatory determinations themselves are not always clear on the exact coverage and in places are open to various interpretations.

As a result, it would be appropriate for IPART to attempt some form of quantification of the retail margin, rather than relying predominantly, or solely, on a comparison of regulatory determinations.

7.7 Estimation of the appropriate retail margin

For the purpose of this section it is assumed that the retail margin should recover costs in relation to:

- A return on and of customer acquisition costs;

- A return on and of tangible assets excluding working capital;
- A return on working capital; and
- Compensation for asymmetric risks.

As noted previously, these are all costs that a new entrant retailer would incur and would require compensation for. If they are not recovered in the retail margin they will need to be recovered as line items in operating costs.

7.7.1 Contribution of customer acquisition costs to retail margin

Integral has adopted a real pre tax WACC of 8% as the required return on acquisition costs, consistent with the lower end of the 8% to 10% range adopted by ESCOSA in September 2004.

The appropriate rate of amortisation of customer acquisition costs depends on the average life of a customer so acquired. A ruling by the Australian Accounting Standards Board (AASB) has specified that customer acquisition costs should be capitalised and amortised over the life of the customer contract for which they were incurred.[50] However, from an economic perspective it is more appropriate to amortise these costs over the *expected life* of the customer (to the extent that there is a material probability that the customer will stay with the retailer after the end of their initial contract).

For the purpose of this report Integral has adopted an average life per customer of 10 years for a new entrant as detailed in the NERA report in Appendix C.

As discussed earlier, Integral believes that the best estimate of customer acquisition costs from energy market data is $524 per customer. Amortising $524 over 10 years at a WACC of 8% results in an annual return of $78. This represents around 5.9% of the average annual electricity bill for Integral's customer base[51].

7.7.2 Contribution of working capital to retail margin

Electricity retailers generally recover their revenues between at least 1 and 3 months in arrears reflecting the fact that customers are on either monthly or quarterly billing cycles. In general, retailers' costs are paid on much shorter terms than this (eg, energy and network costs).

This means retailers must finance substantial working capital. Consequently, it is appropriate to provide a working capital allowance to cover this (as per IPART's most recent network decision). For the purpose of this report, Integral has estimated that working capital is around 1 month of retail revenue.

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[50] See AASB *Subscriber acquisition costs in the telecommunication industry*, Urgent issues group – Interpretation 1042, December 2004.

[51] Covering regulated and unregulated customers in 2005/06.

One month of working capital at a WACC of 8% contributes 0.7% to the required margin.[52]

7.7.3 Compensation for hedging and other risk

When there is no regulatory asset base to act as a 'buffer' capable of absorbing shocks and preventing insolvency, it becomes acutely important that compensation for asymmetric risks be explicitly included in the regulatory determination. The Victorian ESC has recognised this in its recent Pacific National rail access determination where an 8% margin on operating cost was allowed in compensation for such risks (Pacific National has no regulatory asset base as its rail assets were gifted to it by the Victorian Government).[53]

The absence of a regulatory asset base in electricity retailing poses the same problems. In fact, the need for explicit compensation for such risks is even more acute due to the greater exposure to volatility in NEM prices and the greater risks associated with events such as 'billing malfunctions' that was an important contributor to the collapse of OneTel.[54] In order to attract equity and debt finance an electricity retailer would have to provide compensation to investors for these risks.

While it is difficult to quantify the cost of such risks, Integral notes that IPART allowed a 2% margin previously and this was intended to cover a return on tangible assets plus asymmetric risks not covered elsewhere (with the explicit exclusion of energy purchase risks which IPART excluded due to the existence of the ETEF). Integral estimates that the return on tangible assets contributes around 0.7% to the margin. This suggests that IPART implicitly allowed a 1.3% margin for asymmetric risks.

If it is accepted that a 1.3% margin covers these risks and add a further 0.7% compensation for energy purchase risks faced by a new entrant (who does not have access to ETEF) then an allowance of 2% is derived. This is considered to be a conservative estimate.

7.7.4 Contribution of tangible assets to the retail margin

A new entrant will require compensation for the capital financing costs and deprecation in the value of its tangible assets.

Integral has estimated an allowance in the retail margin of around 0.7% and 0.8% is required to compensate for return on and of tangible assets.

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52 ie, 0.08/12 = 0.66666

53 Essential Services Commission, Pacific National - Proposed Access Arrangement Final Decision, May 2006, page 93.

54 See, for example, http://www.consensus.com.au/ITWritersAwards/ITWarchive/ITWentries02/I9AgnesKing.htm where it is suggested that "One.Tel's billing system is riddled with errors, sometimes failing to generate bills and compounding already hefty overheads". Also see, http://www.theage.com.au/articles/2002/08/08/1028157993074.html for similar suggestions.

7.7.5 Appropriate Range for the Retail Margin

Based on each of the conclusions listed above, the total margin required adds to 10% (see middle column of table below). This reflects the level Integral believes to be a conservative estimate of the probable margin a new entrant will require. However, it is useful to examine the implications of changing some of the above assumptions on the total margin allowed.

Assumption/contribution to margin	Low	Medium	High
Customer acquisition costs	300	524	700
WACC	6%	8%	10%
Average customer life in years (new entrant)	7	10	13
Working capital	1mth revenue	1mth revenue	1mth revenue
Contribution of customer acquisition costs	4.1%	5.9%	7.5%
Contribution of working capital	0.5%	0.7%	0.8%
Contribution for asymmetric risk	1%	2%	3%
Contribution for return on tangible assets	0.5%	0.7%	0.8%
Contribution for return of tangible assets	0.8%	0.8%	0.8%
Total	**6.9%**	**10.0%**	**12.9%**

Table 7.4 - Margin sensitivity analysis

The above table illustrates the impact of changes in assumptions relating to: the value of customer acquisition costs; the WACC; the average life of a customer; and the contribution for asymmetric risk.

Many of the components of the margin are amenable to a direct calculation. This submission argues for this approach and recommends that an appropriate retail margin for a new entrant should cover a return on, and amortisation of, customer acquisition costs, a return on and of physical systems, a return on working capital and an allowance for asymmetric risks.

This approach results in a margin increase from 2% to around 10% for residential customers. This change is largely explained by a return on, and of, investments in customer acquisition costs of $524 per customer, which are part of the costs a mass market new entrant retailer would face, as required to be considered in the TOR.

8 Retail operating costs

The Minister's Terms of Reference require IPART, in making its investigation and report on the setting of tariffs for small retail customers, to consider the appropriate 'mass market new entrant retail costs' and the 'mass market new entrant retail margin.'

The Terms of Reference reflects a significant departure from the approach that IPART was previously required to adopt, which was to estimate the retail costs and retail margin appropriate for a standard retailer.

IPART notes in its Issues Paper that new entrant costs are likely to include additional costs, such as customer acquisition and billing systems, and may lead to a higher overall cost than was included in the 2004 Retail Determination. [55]

In its 2004 Retail Determination, the Tribunal allowed prices to incorporate operating costs of \$70 per customer. This allowance is well below the levels set by regulators in SA, ACT and Victoria in their more recent decisions, which have seen operating cost allowances of \$84 to \$92 per customer, or 20 percent to 31 percent higher than in NSW. The \$70 per customer allowance as set by the Tribunal is below Integral's actual retail costs.

This chapter focuses on the appropriate framework for consideration of retail operating costs with the expectation that costs will be higher than the \$70 per customer previously allowed by IPART as the retail operating costs need to reflect a 'mass market new entrant'. Integral believes that the best proxy for these costs is Integral's existing cost structure, modified by the additional costs (or reduced costs in some cases) that a 'mass market new entrant' would face.

Integral engaged National Economic Research Associates (NERA) to prepare a report on estimating the retail costs for a mass market new entrant. Their report is provided at Appendix C.

8.1 Appropriate retail operating costs

It is important that all relevant costs are reflected in the estimate of the appropriate level of regulated retail tariffs. Exactly where those costs are reflected is of secondary importance, that is, whether they are incorporated within the estimates of retail margin, retail costs or energy costs.

[55] IPART Issues Paper, p. 2.

IPART note in their Issues Paper that the allowances for retail operating costs used in other jurisdictions are higher than the allowance for retail operating costs in IPART's 2004 Determination[56]. For example, a study by CRA of the costs that Victorian electricity retailers may be expected to face, recommended an allowance of $92 per customer. It is important to understand what costs are recovered in the operating cost allowance and what costs are recovered in the retail margin or energy costs when comparing across jurisdictions. It will be important for IPART to clearly state what costs it has determined should be recovered through the operating cost allowance. In making its determination IPART should wherever possible adopt the approach used in other jurisdictions in order to ensure that there is a nationally consistent approach developed over time.

8.1.1 Level of retail costs to serve

Integral's forecast for retail operating costs (including depreciation) will be provided to IPART on a confidential basis as part of the information request due to be issued on 27 September 2006 and will be based on the 2005/06 regulatory accounts.

As part of the regulatory accounts the total costs incurred by Integral Retail will be assessed as direct costs of Integral's Retail and Customer Services and Trading business units plus an allocation of Corporate costs. The retail costs will include:

- Customer care and call centre costs;
- Billing costs;
- Sales and marketing costs;
- Collection and default costs; and
- Retail costs associated with transfers and operating in a contestable market.

Corporate costs including Human Resources, Finance and Regulatory etc, will be allocated to the regulated business based upon cost drivers identified by Integral.

8.1.2 Nature of retail operating costs

In making a decision on the detailed regulatory parameters IPART needs to consider the level of retail costs to be recovered and the way in which these costs vary with customer churn. This is particularly important given the desire to facilitate retail competition.

Integral's operating costs are 47% fixed and 53% variable, while depreciation is 100% fixed. Integral's current operating costs reflect the nature of the retail business and the need for Integral to maintain capacity as a retailer of last resort.

56 IPART Issues Paper, p. 20.

IPART will therefore need to give careful consideration of the effect the average cost of servicing a customer will have on competition. Therefore, the Tribunal must allow a real increase in cost allowances based upon a competitive outcome that is consistent with the TOR. This will require a higher allowance for retail operating costs than IPART provided for in the 2004 Retail Determination.

8.2 Additional costs incurred by a mass market new entrant

The following three categories of additional costs would be incurred by a new entrant:

- The costs associated with customer acquisition (which equates to the implied valuation of Integral Energy's current customer base, i.e., a valuation of intangible assets);

- The costs associated with establishing the physical infrastructure necessary to operate a retail business (e.g., billing systems, call centres). These costs are likely to be higher for a new entrant than for the existing incumbent retailer; and

- Cost differences in retail costs which a new entrant would face compared to the incumbent business, given that the incumbents also own a distribution network business.

As stated previously, Integral believes that the preferred treatment of customer acquisition costs is through the retail margin, and has therefore addressed these costs for a mass market new entrant in the previous chapter. The remaining two cost categories are discussed in turn below.

A new entrant would face costs associated with establishing the necessary physical infrastructure to operate a mass market retail business in NSW. Such costs include the costs of billing and IT systems, and call centres.[57]

The cost of physical systems can be expected to form a much lower proportion of total costs for a retail business than the costs of the investment the business makes in customer acquisitions. However, a return on and of these tangible assets still needs to be incorporated within the overall estimate of the appropriate level of regulated retail tariff.

A conservative approach would be to base the new entrant cost on the historic costs of the incumbent. It is likely that a new entrant's costs would be above the level of historic costs, as a result of the following factors:

- Integral's historic book values provide no compensation for inflation - in reality a new entrant would have to buy these assets at today's prices and not the prices in existence when Integral purchased these assets;

- Integral's historic book values do not include amounts to reflect the establishment costs a new entrant would face - such as feasibility studies, capital raising costs, staff recruitment and other costs associated with project managing entry in to the market;

[57] IPART recognises in its Issues Paper that a new entrant would face these costs: IPART Issues Paper, p.2.

- Integral's historic retail book values involve an allocation of common costs between its retail and network business. A stand alone new entrant retailer would have to recover all these costs from its retailing operations;

- a new entrant would not also own the associated distribution network, resulting in it being likely to face additional B2B costs not currently incurred by Integral; and

- the billing systems a new entrant would need to put in place would most likely need to have the ability to issue time of use bills, in the light of COAG's agreement to roll out time-of-use meters. Integral's current billing system does not have this capability for all mass market customers.

The final category of cost differences relate to differences in operating costs arising from the differences in the ownership of a new entrant and from the fact that the incumbent businesses all also directly own the associated distribution networks for their area.

In particular, although a new entrant would also have to provide a similar level of bank guarantee to NEMMCO as does Integral, the costs of obtaining this guarantee from the commercial banking sector are likely to be different from the costs incurred by Integral.

Similarly a new entrant (if it had less than a BBB credit rating) would need to provide a bank guarantee in order to be able to purchase network services from the relevant distributor. This is an additional cost that Integral Energy currently does not have to face.

9 Customer assistance package

Integral is committed to assisting customers in hardship and, to that end, our hardship program, INpower, was implemented in 2004. As shown in the figure below, since INpower was implemented, more than 6000 customers have been enrolled on the program and are benefiting or have benefited from the individual payment plans put in place to help them meet their payment obligations.

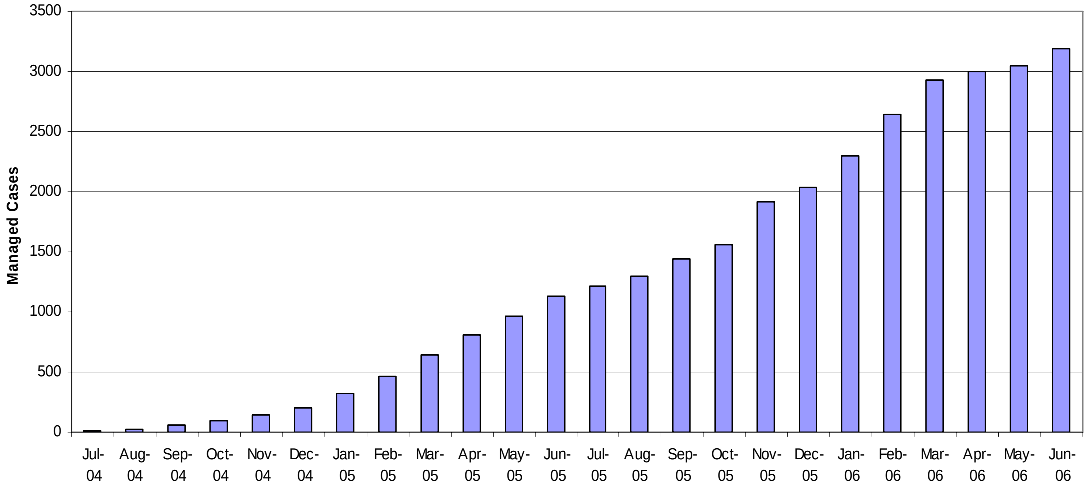

Figure 9.1 – INPower customer assistance program case numbers

The program caters for customers who, for one reason or another, are experiencing ongoing financial hardship. Other customers deemed to be in temporary short term hardship are provided with short term payment plans to help get them back on track.

Customers on the INpower program are assisted in the following ways:

- They are assessed for appropriate government benefits and these are applied to their accounts as necessary;
- Affordable payment plans are determined with the customer. These are designed to help the customer meet their ongoing debt while paying off their arrears;
- If the customer cannot meet the proposed arrangement they are advised of the Energy Account Payment Assistance (EAPA) scheme and provided with the names and addresses of community agencies they can approach for assessment;
- Customers in extreme hardship are encouraged to attend financial counselling with the aim of providing them with holistic assistance;
- Customers who are consuming more than they can afford to pay are offered a free energy audit to assist them identifying areas of high usage and providing them with advice on how to reduce that usage;

- Customers are encouraged to pay using Centrepay and this is facilitated by Integral Energy liaising directly with Centrelink on behalf of the customer; and

- A customer on the INPower program will not be disconnected.

As stated above, customers on the program are removed from the debt collection cycle and assigned to case managers who manage the individual customers. This promotes good will and trust and facilitates the development of relationships with the customers who then have one point of contact in the organisation who understands their individual circumstances.

Customers who do not meet their payment obligations while on the program are given several opportunities to renegotiate their arrangement.

Integral has developed good working relations with the community welfare agencies who have been educated about the program through public forums as well as individual visits as required. Research conducted in May 2006 with customers and welfare groups provided positive feedback particularly in relation to:

- Accessibility;

- Flexibilify;

- Relationships with community wefare organisations; and

- Feelings of safety, relief, hope, calm, respect and patience for customers.

The program is seen as being very positive and it is recognised as playing a big part in getting the customer's financial situation back on track.

Over the last six months the program has been improved through:

- A relaxation of the criteria for referral;

- Further training of all frontline staff on the elements and identification of hardship;

- Process changes to allow earlier identification of hardship and thereby reduce disconnections for non payment;

- Further customisation of payment plans to suit the individual needs of the customer.

At this stage the improvements have contributed to the reduction of disconnection rates by approximately 38% compared to a similar period last year. We have also begun to see a decrease in the number of customers turning to EWON for assistance in managing their accounts.

Integral Energy has also introduced a trial incentive program where the company will match each sixth payment made on time for customers who will be on the program for more than a year. This will further assist customers in reducing their debt as well as play a part in reducing the length of time they are expected to take to pay off their account.

The program has been working well for customers and we have more than 1000 who have met all their obligations and continue to manage their accounts through the ongoing use of Centrepay. Customers who have left the program as a result of full payment are monitored to ensure they continue to manage their accounts to allow for early detection of possible future problems. Where these are detected the customer is contacted and invited back to the program.

In July 2006 the Minister for Energy announced new measures aimed at providing assistance to those customers who are experiencing difficulty paying their energy bills. Under these measures, which take effect in October 2006, energy retailers will consider customers' financial circumstances which could lead to some customers being offered time to pay their bills by instalments. As well as ensuring energy retailers discuss instalment plans with their customers, the changes also mean energy retailers will be asked to develop and implement a Code of Practice for managing bill payment difficulties.

These new measures are in addition to the existing customer protection provisions which include:

- Two written notices prior to disconnection;
- At least 14 days notice of a disconnection;
- Reasonable attempts to contact customers by phone or in person;
- No disconnections on a weekend, a day immediately preceding a public holiday or a public holiday; and
- No disconnections while there is an application for Government assistance, or assistance under a payment plan; or if a dispute is before the Energy Ombudsman.

Integral is working on system changes to automate payment plans. The development and implementation of this system will assist Integral in continuing reduction in the number of disconnections and assisting our customers with their financial management. The automated payment plans system is expected to be completed by July 2007.

Integral believes that its customer assistance program, when combined with customer protection legislation and high levels of price competition, could underpin the removal of retail price regulation.

10 Miscellaneous charges

The Government's TOR for the electricity review require the Tribunal to consider and report on the basis for regulating miscellaneous charges and security deposits.

This Chapter sets out Integral's proposal to change the basis for charging various non-tariff charges.

10.1 Current non-tariff charges

The Electricity Supply Act 1995 (ESA) establishes a list of electricity non-tariff charges that the Tribunal may regulate by determining the charges, or the specific methodology for determining the charges. These charges are limited to:

- late payment fees;
- security deposits;
- fees for dishonoured bank cheques.

10.2 Late Payment Fee

Late payment fees are aimed at encouraging behavioural change among late paying customers to recover some of the significant costs associated with administering reminder and disconnection notices and to ensure those customers bear the cost of their actions.

Integral's policy for late payment fees is:

Late payment fees will not be levied on outstanding invoice payments:

- during the period of an extension payment time agreed between Integral and the customer;
- where a customer has made a billing related complaint to the Energy and Water Ombudsman NSW, or another external dispute resolution body, and where that complaint is unresolved; or
- during the period of an instalment arrangement agreed with Integral.

A late payment fee will be waived:

- where the customer has contacted a welfare agency/support service for assistance;
- where payment or part payment is by EAPA voucher; or
- on a case by case basis as considered appropriate by Integral or the electricity industry ombudsman under an approved electricity industry ombudsman scheme under the Act.

A late payment fee will only be levied:

- on or after the date which is at least five business days after the due date shown on the invoice that is the subject of the late payment; and
  after the customer has been notified in advance that the late payment fee will be charged if the invoice is not paid, or alternative payment arrangements entered into, within five business days of the due date.

Late payment fees are limited to a maximum of one per bill.

Integral's current late payment fee for each overdue invoice was set in the 2004 Retail Determination and is $5.45 (incl GST). The fee has not been increased since the 1999 Determination. Since then there has clearly been an increase in costs.

Integral proposes that the allowance for the late payment fee should be aligned with the level of the fee in those jurisdictions where a late payment fee is charged and also aligned with the level of the fee charged by gas retailers. Integral notes that AGL currently charges customers a late payment fee of $11.44 (including GST).

Integral also proposes that the fee be set as a maximum fee and the retailer be given the flexibility to charge a lower fee or to waive the fee if the circumstances warrant.

A late payment fee set at the level proposed will:

- Be more cost reflective;
- Encourage Integral's customers to settle their accounts within Integral's existing payment terms rather than incur a late payment fee; and
- Be more consistent with competing energy providers. This level will encourage customers to give equal priority to payment of their electricity account with other energy bills.

10.3 Security Deposit

Integral requests that the Tribunal review the current requirement to request a security deposit at the commencement of the supply agreement. Integral believes that the option of charging a security deposit during the life of the supply agreement should be introduced based on the customer's credit rating and payment history. This has the advantage of providing:

- Greater flexibility in managing credit risk during the life of the agreement;
- The ability to use the security deposit as an alternative to disconnection;
- Timely collection of outstanding debt whilst managing customer debt exposure.

The flexibility created by the above may also lead to Integral offering more of its customers the option of commencing their supply agreement without the need for a security deposit upfront.

Integral therefore believes the security deposit should be able to be charged during the life of the supply agreement.

Integral currently charges the following security deposits:

- Residential customers - $180.00
- Business customers on monthly accounts - $510.00
- Business customers on quarterly accounts - $930.00

These amounts have been calculated in accordance with the 2004 IPART Determination, that is, for monthly accounts the security deposit is 2.5 times the average monthly account and for quarterly accounts the security deposit is 1.5 times the average quarterly account.

10.4 Dishonoured Bank Transaction Fee

Currently, Integral is only able to charge fees associated with dishonoured cheques. However, with the additional payment channels (such as Direct Debit and Credit Card Payments) offered by Integral, this definition needs to be expanded.

Integral therefore submits that the definition in the *Electricity Supply Act* 1995 (NSW) for "regulated retail charges"[58], insofar as it includes a fee for dishonoured bank cheques, should be expanded to include other payment channel such as Direct Debit and Credit Card Payments. This will bring the NSW electricity industry into line with the NSW gas industry and other interstate gas and electricity retailers.

[58] See the Dictionary in the *Electricity Supply Act* 1995 (NSW)

11 Glossary

Term	Definition
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital territory
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
BOM	Beureau of Meteorology
COAG	Council of Australian Governments
CPI	Consumer Price Index
EAPA	Energy Account Payment Assistance
EPCA	Energy Purchase Cost Allowance
ERM	Energy Risk Management
ESA	Electricity Supply Act
ESCOSA	Essential Services Commission of South Australia
ETEF	Electricity Tariff Equalisation Fund
EWON	Energy & Water Ombudsman of NSW
FoPC	Form of Price Control
FRC	Full Retail Contestability
GST	Goods & Services Tax
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal of NSW
kWh	Kilowatt Hour
LECG	LECG Limited
LRMC	Long Run Marginal Cost
MCE	Ministerial Council on Energy
MRET	Mandatory Renewable Energy Target
MWh	Megawatt Hour
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company Ltd
NERA	National Economic Research Associates
NGAS	NSW Greenhouse Gas Abatement Scheme
NSL	Net System Load
NSLP	Net System Load Profile
NUoS	Network Use of System
NSW	New South Wales
REC	Renewable Energy Certificate

Term	Definition
SA	South Australia
TOR	Terms of Reference
ToU	Time of Use
Tribunal	Independent Pricing and Regulatory Tribunal of NSW
US	United States of America
WACC	Weighted Average Cost of Capital
WTP	Wholesale Transfer Price

12 Appendix A – NERA Economic Consulting report on form of price control

7 September 2006

Form of Price Control

Integral Energy

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The Role of the Form of Price Control (FoPC)

The FoPC gives effect to regulatory objectives. Consequently, when there are multiple, sometimes competing, regulatory objectives the FoPC must serve multiple objectives. As a general rule, price regulation is only desirable where one or more businesses possess market power and can be expected to abuse that market power in the absence of price regulation. If little or no market power exists then the rationale for price regulation is seriously weakened. In the current context, it is possible to identify six potential criteria used to assess alternative FoPC arrangements, namely that the FoPC:

1. should competition not be sufficiently effective, protects customers from inappropriate monopoly pricing by standard retailers;
2. allows standard retailers to recover (efficient) costs;
3. promotes competition as a more efficient alternative to regulation in the protection of customers from monopoly pricing;
4. prevents excessive price shocks to individual retail customers;
5. minimises regulatory compliance and administrative costs; and
6. is consistent with regulatory precedent in other jurisdictions where retail competition has been successfully implemented.

Choices in Relation to the FoPC

The first choice that must be made in relation to the FoPC is whether to impose formal price regulation or price monitoring. By formal price regulation we mean a FoPC that places specific caps on prices/revenues. By price monitoring we mean a framework within which the regulator monitors and reports on pricing conduct in the market with the implied threat of future imposition of formal price regulation if that conduct is found to involve inappropriate exercise of market power. Price monitoring is generally only preferable where there is a competitive constraint that can be, at least in part, relied on to restrain inappropriate pricing.

The advantage of formal price regulation relative to price monitoring is that it provides regulatory certainty to the businesses involved. The disadvantage is that it does so at the cost of a higher probability of regulatory error. This is because the pricing formulas developed by the regulator can never be expected to capture and reflect all the pertinent economic circumstances over the life of the regulatory determination.

Price monitoring is, in our view, the appropriate FoPC for retail electricity in NSW. The primary reason for this recommendation is that electricity retailing is already a highly competitive industry. In other jurisdictions, such as the UK, competition has been successfully relied on to constrain monopoly pricing without the need to resort to formal price regulation. Even in the ACT where there has been relatively limited actual entry by competitors, the ICRC has recommended a move to price monitoring on the basis that observed low entry barriers mean the threat of entry can be relied on to prevent monopoly pricing. Detailed reasons for our recommendation are provided in Section 2 of this report.

Notwithstanding the above, we recognise that a move from the current, highly prescriptive, FoPC directly to an informal price monitoring regime may be viewed as too radical a change in the current review. It may also be arguable that IPART's terms of reference rule consideration of price monitoring (ie, require formal price regulation). In this context, we also set out our view of the minimum appropriate changes to the current formal FoPC arrangements. However, before doing so it is useful to identify and categorise the five key decisions that need to be made when designing a formal FoPC.

1. The definition of what exactly is being controlled (eg, average prices per kWh (ie, revenue divided by energy), weighted average prices, revenue (ie, with no allowance for volumes)).
2. The level at which the price control is applied (eg, is it applied to individual tariffs or to average prices/revenues);
3. The use of side constraints (eg, the current CPI+5% or $35 limit on the allowed annual increase in the average bill on each tariff);
4. The inclusion of pass through mechanisms and the frequency of price control resets; and
5. The tariff quantities used in the price control compliance assessment (eg, historic or forecast).

NERA Recommendations on Formal Price Control

We summarise our recommendations on how a formal price control should be implemented (assuming a prior decision has been made not to implement price monitoring). In doing so, we describe the way in which the above five decisions are made under the current FoPC and highlight where (and why) we believe changes should be made.

Decision 1 - What should be controlled?

The current FoPC is best described as a weighted average price cap.[1] We see no compelling reason to move away from this approach and recommend that it be retained on an aggregate tariff level.

Decision 2 - At what level should the control be applied?

The current FoPC applies the control at the level of individual tariffs. That is, an allowable percentage increase in weighted average prices is independently derived for each tariff (in the terminology of the current FoPC this is the increase that is consistent with not breaching 'target R' for that tariff). Retailers do not have the flexibility to raise prices on one tariff by more than this even if it is offset by smaller than allowed increases on other tariffs.

We strongly recommend that this aspect of the current FoPC be amended and that the price control be applied at the level of aggregate tariffs only. A prescriptive tariff level FoPC increases the complexity of the cost modelling the regulator must undertake. Not only must the regulator estimate total retail costs but must also allocate those costs amongst tariffs.

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[1] Each year price increases are assessed to determine whether the percentage increase in average prices (weighted using historical quantities) exceeds a predetermined level.

Even with perfect information on costs such an allocation will inevitably be arbitrary in the presence of costs that are common across tariffs (eg, billing systems, corporate overheads, corporate branding etc). In reality, the regulator will not have perfect information on costs and, even if it did at the beginning of the period, this information will quickly become outdated *during* the period.

The existence of common costs and imperfect information means that errors will be made in attributing costs to individual tariffs. In the presence of contestability, these errors will have asymmetric impacts on retailers. Under-estimates of cost for one tariff will result in a windfall loss to the regulated retailer on that tariff. By contrast, over-estimates of cost for another tariff will not result in an offsetting windfall gain because competition will impede the business from pricing above cost (even if regulation allows it).

This asymmetry means that, in order to achieve the objective of cost recovery, cost modelling must be more generous under the current FoPC than under a FoPC that is applied at the aggregate level. This is a simple reflection of the fact that where an aggregate FoPC applies, it requires fewer regulatory decisions and, as a consequence, has smaller scope for regulatory error.

Thus, use of a FoPC applied to aggregate tariffs is more likely to satisfy both criterion one and two (above) while application at an individual tariff levels can be expected to satisfy criterion one at the expense of criterion two.

It is worth noting that we are unaware of any other jurisdiction transitioning to competitive markets where prescriptive regulation is applied at the level of individual tariffs. It is also worth noting that, unlike the case for natural monopolies, the threat of competition gives standard retailers a strong incentive not to engage in allocations of aggregate costs that would be perceived as unfair by their customers (as those customers have the option of switching to other retailers).[2]

Decision 3 - What side constraints, if any, should be applied?

The role of side constraints is to prevent excessive price shocks to individual consumers (criteria 4 above). The important question in the current context is ‘what is excessive’? On one view, an increase in prices that moves those prices closer to cost, but not above cost, is not excessive - irrespective of how large it is. On this view there is a limited rationale for side constraints, given that above cost pricing to individual customers will expose the retailer to switching by those customers it is reasonable to question the need for any side constraints. Moreover, side constraints impose restrictions in tariff reform that can prevent the achievement of full cost recovery (criteria two above).

We are sympathetic to the view expressed above and recommend that no side constraints be imposed. However, we recognise that large price increases for individual customers, even if it is simply the rapid unwinding of below cost pricing, can create community tensions. If side constraints are imposed to address this, we recommend that their level be calibrated not to unduly delay movements in prices to approximately cost reflective levels.

2 The same is true in relation to the removal of obsolete tariffs. If the removal of obsolete tariffs is likely to be considered unfair by customers then they will have the ability to respond by switching to competitively supplied tariffs.

We also note that to the extent side constraints limit annual price adjustment on under-recovering tariffs, customers on these tariffs will be insulated from attempts by retailers and network operators to employ demand management price signalling. In this regard, we propose that no side constraint be applied. Where a side constraint is applied to regulated retail tariffs, it is appropriate that it only be applied to the retail component of such tariffs. In making this recommendation we note that side constraints are already applied at the network tariff level.

Decision 4 - What pass through mechanisms and frequency of resets?

In the absence of pass through mechanisms retailers face an asymmetric cost of regulatory error in forecasting costs. If forecast costs are too low retailers suffer a windfall loss but if forecast costs are too high competition will constrain their ability to use this to obtain a windfall gain. These asymmetric costs of forecasting error can be reduced by including pass through mechanisms where costs deviate materially from forecasts.

The current FoPC has limited automatic pass through provisions that apply to changes in network tariffs. Other regulatory jurisdictions include automatic pass through mechanisms for a range of costs including energy costs. A failure to have pass through provisions for unexpectedly high energy prices was a prime cause of the Californian ‘energy crisis’ of 2000/01. Several US states, such as Texas, have bi-annual changes in the allowed cost of energy for regulated retailers and a similar annual arrangement exists in Ireland.

We recommend that IPART have regard to implementing a pass through mechanism for actual energy costs. Periodic pass through of actual energy costs is consistent with criterion two and also reduces the risk of regulated retail tariffs being constrained below market prices, thereby better supporting criterion three. If IPART does not implement such a mechanism then retailers should be compensated for the additional asymmetric risk they carry associated with forecast energy prices.

The current FoPC determines a new level of allowable costs every year based on a predetermined view of *unit* costs taken at the beginning of the regulatory period combined with information on historic quantities. This amounts to a mini determination every year where new information on units sold is examined but new information on unit costs is not. In effect, this mini determination sets a new “X” every year. The advantage of having such ‘mini determinations’ is that it better ensures that unexpected changes in quantities are not causing revenues to deviate from costs.[3] We do not see compelling reasons to alter this aspect of the current FoPC.

Decision 5 - What quantities should be used?

An average price FoPC must use quantities to weight individual prices. The current FoPC uses the best estimate of the quantities sold in the prior year. Given that that year is not complete when the next years prices must be approved this involves a mixed use of (un-audited) actual and forecast quantities. In our view this approach is reasonable.

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[3] Noting that this is only a potential issue if retailers’ unit pricing is not reflective of marginal cost.

Nonetheless, we do see some advantage to using forecast quantities to the extent that contestability results in rapidly changing quantities. Moreover, where there is regulatory error in cost estimation, use of more up to date quantities to annually reset retailers' costs (and revenues) will assist to lower the impact of such error. On this basis we recommend that retailers' forecast of quantities in the relevant year be used to weight prices and total revenue calculations. However, we also recommend that retailers be required to simultaneously provide the best estimate for actual quantities in the prior year. This measure can be expected to better achieve the objective of criterion two.

1. Retail Price Regulation Background

The Minister for Energy and Utilities has requested that the Independent Pricing and Regulatory Tribunal of New South Wales (IPART) undertake a review of regulated retail tariffs to apply from 2007 to 2010. The legislative requirements for regulating default electricity tariffs as set out in section 43EB of the *Electricity Supply Act* allow the Tribunal significant flexibility in the form of regulation. Integral has commissioned NERA to provide advice on the available options for regulating retail tariffs and to recommend the most appropriate option(s).

1.1. Purpose of retail price regulation

In order to assess alternative forms of price control (FoPC) it is necessary to first establish criteria by which they might be ranked. The following list of criteria describe the primary criteria against which a FoPC might be assessed.

1. should competition not be sufficiently effective, protects customers from inappropriate monopoly pricing by standard retailers;
2. allows standard retailers to recover (efficient) costs;
3. promotes competition as a more efficient alternative to regulation in the protection of customers from monopoly pricing;
4. prevents excessive price shocks to individual retail customers;
5. minimises regulatory compliance and administrative costs; and
6. is consistent with regulatory precedent in other jurisdictions where retail competition has been successfully implemented.

IPART is required to review regulated retail prices for the period 2007 to 2010 taking into account 'the NSW Government's policy aim of reducing customers' reliance on regulated prices, and the likely effect of its determination on competition in the retail electricity market.'[4] This suggests that considerable weight should be given to criterion 3 above.

It is also worth noting that criterion 4 was included in terms of reference for past retail reviews but has not been explicitly included in the current retail review. This suggests that criterion 4 should be given less weight.

IPART's terms of reference also specify that the form of retail regulation is required to "Ensure tariffs are cost reflective by 2010" which suggests weight should be given to criterion 2. While no explicit mention of criteria 1, 5 and 6 are made in the terms of reference, it seems reasonable to assume that they are implicit.

In determining the optimal form of regulation, it is also useful to identify what conditions have changed since the previous review of regulated retail tariffs. In this regard, notable market, policy and regulatory developments include:

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[4] IPART, Review of Regulated Retail Tariffs and Charges in NSW - 1 July 2007 to 30 June 2010 - Issues Paper, July 2006, page 1.

- cessation of the Electricity Tariff Equalisation Fund (ETEF);
- greater customer experience with retail competition and sustained levels of customer switching (averaging 5% over the period);[5]
- growing use of price monitoring as a transitional regulatory approach as electricity retail markets are increasingly characterised by effective competition;
- changes in the terms of reference issued to IPART whereby IPART is explicitly required take into account the costs of a new entrant mass market retailer and is not explicitly required to take into account customer impacts.

With this background the below sections provide a summary of our views on the weights that should be given to each of the above criteria.

1.1.1. Criteria 1 - Protecting consumers from monopoly pricing

This must be a primary objective of the FoPC. Without this objective there is no rationale for having a FoPC at all. That said, the existence of competition as an alternative control on monopoly pricing must be borne in mind in determining whether a light or heavy handed FoPC is implemented.

1.1.2. Criteria 2 - Allowing cost recovery

As with all regulation equal importance must be given to allowing cost as to preventing monopoly pricing. If cost recovery is not allowed then the long term viability of the service is put under threat.

1.1.3. Criteria 3 - Promotes competition as an alternative to regulation

Both the terms of reference and section 43EB(2)(b) of the *Electricity Supply Act* require IPART to have regard to the impacts of its regulatory approach on competition in the retail electricity market. This criterion assesses these requirements based on the extent to which the particular regulatory approach helps to facilitate competition and relies upon such competition to delivery customer protection whilst simultaneously achieving allocative efficiency in terms of distributing electricity resources.

If weight is given to this criterion above and beyond the weight given to criterion 2 (as the terms of reference seem to do) then it suggests that the IPART should err on the side of caution when regulating prices. We consider that this is appropriate.

Where retailers set (and fix) their prices for an entire year, it is essential that these prices reflect their best estimate of the costs of supply over the coming year. This is because annual price fixing already introduces a barrier to the efficient adjustment of prices with respect to retailer's dynamic cost pressures. The FoPC should ensure that retailers' decisions in setting cost reflective tariffs are not (further) impeded by regulatory arrangements. Given the dynamic nature of retailers' costs (particularly given the cessation of the ETEF),

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5 See Peace Software and VaasaEmg Utility Customer Switching Research Project http://www.peace.com/customer-switching/graphics-b.html

arrangements that attempt to fix costs for periods in excess of one year will likely further reduce retailer's ability to levy cost reflective tariffs.

1.1.4. Criteria 4 - Prevents excessive price shocks

While it is important that tariffs are transitioned to cost reflective levels (based on the costs determined through this review), it can also be argued that, where possible, customers should be protected from excessive price shocks in any one year, to the extent that the course of such shocks is within retailers' control. The problem then becomes defining 'excessive' especially if the price change is required to move towards cost reflectivity.

We do not believe that strong weight should be given to this criterion on the basis that:

- there is ambiguity over the meaning of 'excessive' price shocks;
- if price shocks result in above cost pricing customers can switch to competitors;
- the terms of reference omit price shocks as a consideration; and
- attempting to control 'price shocks' will impede the achievement of criteria 2 and 3.

1.1.5. Criteria 5 - minimises compliance and administration costs

Administration and compliance costs incurred though ensuring compliance with regulatory requirements represent a financial burden on retailers and ultimately a financial burden on customers. For these costs to be incurred efficiently, it is necessary to ensure that the application of the particular regulatory approach provides a net benefit to competition and customers after taking into account the financial burden of regulatory compliance.

Weight should be given to this criterion in proportion to any differences in compliance costs across alternative FoPC.

1.1.6. Criteria 6 - regulatory precedent

Other things equal, a FoPC that operates successfully in other jurisdictions should be preferred to one that does not.

2. Preferred Form of Price Control

The evolution from franchise or monopoly retail service areas to full retail contestability with competitive retail markets has been facilitated by regulatory measures in a number of jurisdictions around Australia and the World. Regulators have adapted to this evolution by continually reviewing and ensuring their regulatory frameworks do not hinder this process by damaging competition or deterring entry by new retailers.

We understand that there is some doubt as to whether price monitoring is consistent with IPART's terms of reference. However, for the reasons outlined below, we consider that, in the absence of legal constraints, it should be adopted as the preferred form of price control.

2.1. Price monitoring

Those jurisdictions that have identified that the conditions for effective retail competition have been established have tended to move to price monitoring or other more light handed regulatory approaches. This is the case in the ACT in Australia where the most recent regulated retail tariff concluded that:

> *'the ACT retail electricity market exhibits the characteristics of a competitive market and that the continuation of a regulated retail tariff is no longer required.'*[6]

The characteristics upon which the ICRC determined that the ACT electricity retail market was consistent with a competitive market were:

- the existence of a number of competing retailers and/or the imminent potential entry of new competitors.
- actual and/or potential competition between these retailers.
- innovation in the products and services offered to consumers by active retailers.

It is apparent that all these characteristics are also evident in the NSW electricity retail market. On this basis we consider it appropriate that a price monitoring framework also be adopted in NSW.

In recommending the removal of regulated retail tariffs, the ICRC proposed that a 'deemed contract' be established which effectively takes the place of the current regulated retail tariff (called a transitional franchise tariff). While this 'deemed contract' will not have a regulatory determined price or price path (ie, ActewAGL can vary its prices as it sees fit) it will continue to afford customers the same consumer protections contained in the current regulatory arrangements including:

- obligation to supply on a non-negotiated deemed contract;
- ability for customers to move on or off the deemed contract at their discretion; and

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[6] ICRC, Final Report Retail Prices for Non-contestable Electricity Customers, April 2006, page 2.

- no minimum periods for the deemed contract and no exit fees.

The ICRC also proposed that the retail pricing performance of this regulatory regime be monitored over the next 4 years (out to 2010) to ensure that effective competition remains a sufficient discipline on retail pricing thereby ensuring retailers do not earn excessive monopoly revenues. If it is found that the deemed contracts are excessively high, the ICRC in conjunction with the ACT government will consider the re-imposition of more intrusive retail tariff regulation.

This form of regulation is also applied in the UK, although, the threat of re-regulation has not been explicitly made. The last regulations on retail prices in the UK gas and electricity markets were removed in April 2002. However, OFGEM (the UK regulator) still enforces certain customer protections via supply licence conditions. These conditions are the subject of a current review aimed at reducing these conditions and relying to a greater extent on:

- the effective competition in the gas and electricity retail markets; and
- existing consumer protection laws that apply to all industries in the UK.

In July 2006 OFGEM released its initial policy proposals for the review which propose the removal of certain requirements such as contract cool-off periods, regulation of termination fees and publication of supply terms. The removal of these license conditions has been justified by the sustained presence of effective competition, enhanced potential for self-regulation, desire to simplify licence terms to foster new retailer entry and establishment of the Energy Services Ombudsman.[7]

Provided price monitoring is consistent with IPART's terms of reference, we propose a price monitoring approach be adopted from 2007 onwards - with the threat of more formal regulation in the unlikely event that competition does not properly discipline incumbent retailers. The price monitoring approach may be of the form proposed by the ICRC or may be applied by reference to market offerings. IPART's terms of reference rule consideration of price monitoring (ie, require formal price regulation).

Conclusion 2.1

Consistent with criterion 6, regulatory precedent in other jurisdictions suggests price monitoring is an effective form or regulation for electricity retailers.

2.1.1. Price monitoring in other industries

The regulation of Australian Airports and Victorian Shipping Ports are both examples of price monitoring regimes. In these industries, this form of regulation essentially involves a regulator taking a less intrusive role of 'tracking' prices, profits and quality over a period of time – normally by reference to an established set of overarching pricing principles. The regulator can recommend further action, such as explicit price control, if it believes such action is warranted, eg, if it believes that the pricing principles have been violated. The

[7] See OFGEM Supply Licence Review – Initial Policy Proposals, July 2006.

Productivity Commission has commented that price monitoring frameworks are ideal when industries:[8]

> *'[A]re in transition to a more competitive environment or where there are concerns about the strength of competitive pressures'.*

Details of current use of price monitoring regulatory arrangements in these industries are contained in case studies of Australian Airports and Victorian Ports in Appendix B.

2.2. Benefits of a price monitoring approach for NSW

Under a framework of price monitoring IPART can still gain comfort that retailers will implement tariffs that are cost reflective. This is because retailers will face competitive pressure to price at cost reflective levels.

2.2.1.1. Competition for retail customers

In a competitive retail market, attempts by incumbent retailers to charge monopoly prices will cause customers to switch to new entrant retailers with more competitive retail prices and service conditions.

That is, where a retailer attempts to levy tariffs that exceed cost reflective levels, other retailers can be expected to 'undercut' these tariffs and entice the customers onto more cost reflective tariffs. This is true whether there are multiple retailers already competing in the market, or whether there is a credible threat that new retailers will enter the market where they see over-recovery occurring.

Importantly, the existence of competition not only makes price monitoring more attractive it also make heavy handed regulation less attractive. . As discussed below, competition for customers introduces asymmetry in the impacts of regulatory errors. This is because setting prices too low results in windfall losses but setting prices too high does not result in windfall gains because competition constrains pricing materially above cost.

2.2.1.2. Retention of general consumer protections

The use of price monitoring will involve the retention of existing consumer protections either within the Electricity Supply Act (similar to the approach proposed in the ACT) or in the conditions contained in retail supply licences (as adopted in the UK).

Common customer protections that could be retained may include:

- hardship provisions;
- disclosure provisions;
- obligation to supply on a deemed tariff with no minimum period or exit fees; and
- retailer of last resort provisions.

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8 Productivity Commission, *Review of the Price Surveillance Act 1983,* August 2001, p.97.

2.2.2. Price monitoring and regulatory objectives

As identified above the key objectives of retail electricity tariff regulation are to allow retailers to recover efficient costs, ensure cost reflectivity in tariffs, allow regulated tariff rationalisation, promote competition and minimise compliance costs. Price monitoring is an efficient means of achieving these objectives whilst imposing least risk of regulatory error and minimising compliance costs. Furthermore, price monitoring can be expected to impose the least distortion on the evolution of the competitive electricity retail market. Table 2.1 summarises how price monitoring meets the stated regulatory objectives.

Table 2.1
Summary of regulatory objectives

Objective	Attainment through price monitoring
Prevents monopoly prices	Indirectly through the threat of re-regulation. The primary reliance to prevent monopoly pricing is on competition.
Allows recovery of efficient costs	Yes - to the extent that competition allows
Promotes competition	Yes. Removes risk that regulated tariffs will be below true costs, thereby removing threat that competitors will not be able to compete effectively
Prevents 'excessive' price shocks	Only if 'excessive' is defined as increases in prices above competitive levels
Minimises compliance costs	Yes. Annual compliance submission and approval process will be removed thereby removing the associated costs.
Regulatory precedent	Yes. Regulatory precedent in the UK energy markets, and in other Australian jurisdictions

2.3. Current 'formal' price regulation

It may be that, for legal or other reasons, IPART prefers formal price regulation to price monitoring. If so, then IPART must consider whether the current formal price control arrangements can be improved on.

Section 3 below attempts to identify the individual components of a formal price control mechanism. In that section we identify five key issues that must be decided when building a form of price control and we separately recommend on each. However, before we do so it is useful to note that the current N+R form of regulation adopted by IPART is, in effect, a form of weighted average price cap applied to individual tariffs.

IPART's current form of price control can be specified as: a weighted average price cap; (a) applied at the level of each individual tariff; (b) using historic quantities to test compliance; (c) with a new X-factor calibrated each year. This may seem surprising given that the form of regulation is presented as a 'revenue target'. Nonetheless, it falls into the category of weighted average price cap (albeit with "X" reset each year).

Each year IPART uses predetermined estimates of cost variables (per customer and per kWh) and historic quantities to determine the 'retail cost' on a specific tariff. IPART then multiplies the same quantities by proposed retail prices (net of network prices) for that specific tariff to derive an estimate of retail revenue on that tariff. IPART then approves the price increase if its estimate of revenues is less than its estimate of retail cost. That is, prices are approved if, each year:

$\sum_i C^i \cdot q^i_{t-1} \geq \sum_i P^i_t \cdot q^i_{t-1}$; where C^i is IPART's (unchanging) estimate of the unit cost of supplying q^i.

Formulaically, this is identical to IPART specifying that weighted average prices (using q^i_{t-1} as the weights) must not increase by more than X this year - where X is re-determined each year as:

$$\frac{\sum_i C^i \cdot q^i_{t-1}}{\sum_i P^i_{t-1} \cdot q^i_{t-1}} = X \geq \frac{\sum_i P^i_t \cdot q^i_{t-1}}{\sum_i P^i_{t-1} \cdot q^i_{t-1}}$$

Specifying the current form of regulation in this manner allows us to identify precisely how other forms of regulation might differ. For example, the **minimalist** change required to achieve average tariff regulation (rather than specific tariff regulation) is to introduce a weighted average price cap for all tariffs where X is reset each year as:

$$X = \frac{\sum_j \sum_i C^{ij} \cdot q^{ij}_{t-1}}{\sum_j \sum_i P^{ij}_{t-1} \cdot q^{ij}_{t-1}}$$

The only difference between this approach and the current approach is that:

- the current form of price control respecifies a new X-factor each year for the weighted average increase in prices *on each tariff*; while
- the above form of price control respecifies a new X-factor each year for the weighted average increase in prices *across all tariffs*.

An additional change to the current arrangements could be achieved by, for example, setting a single X-factor over the entire regulatory period. This would be very similar to the manner in which the weighted average price cap is set for network prices. [This can only have a material effect if the structure of the retailer's tariffs (net of network tariffs) is different to IPART's estimate of the structure of costs (eg, per customer versus energy).]

3. Assessing Formal Price Control Options

The nomenclature around formal versions of price control can be confusing and include:

- The current NSW arrangements 'N plus target R';
- Revenue or average (weighted or total consumption based) tariff regulation;
- Relaxed price movement limits (under current and/or average tariff regulation); and
- Relative tariff regulation.

However, these terms do not fully define each form of price control.[9] Each of the price controls listed above (excluding price monitoring and relative tariff regulation) involve a number of key components elements each of which include a range of options. The five key components of a price control are:

1. The definition of what exactly is being controlled (eg, average prices per kWh (ie, revenue divided by energy), weighted average prices, revenue (ie, with no allowance for volumes)).
2. The level at which the price control is applied (eg, is it applied to individual tariffs or to average prices/revenues);
3. The use of side constraints (eg, the current CPI+5% or $35 limit on the allowed annual increase in the average bill on each tariff);
4. The inclusion of pass through mechanisms and the frequency of price control resets; and
5. The tariff quantities used in the price control compliance assessment (eg, historic or forecast).

The following sections consider each of these price control components in more detail taking into account the regulatory objectives set out in section 1.

3.1. Definition of What is Being Controlled

As described in the previous section, the current FoPC is best described as a weighted average price cap.[10] We see no compelling reason to move away from this approach and recommend that it be retained.

3.2. Level at Which the Price Control is Applied

The primary objective of price regulation is (normally) to prevent firms with market power from using that power to earn monopoly profits. This objective is achieved via the setting of

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[9] Indeed, as already discussed, the current arrangements are themselves a form of weighted average price cap. (Notwithstanding this, Appendix A summarises the relative merits of what each of these terms are generally taken as meaning.)Appendix A

[10] Each year price increases are assessed to determine whether the percentage increase in average prices (weighted using historical quantities) exceeds a predetermined level.

a global price/revenue cap on all of the services for which the firm has market power. The question then becomes to what extent, if any, should the regulator also play a role in setting the individual prices charged by the firm? For example, and in the current context, to what extent should the regulator determine prices for disaggregated services such as:

- the prices charged for peak versus off peak energy?
- the prices for non-TOU energy consumed on one tariff versus non-TOU energy consumed on a different tariff - noting that customers on different tariffs (eg, residential versus business) will tend to have different load profiles? and
- the prices for energy versus the fixed price per customer?

The answer to these questions depends on whether the regulator or the business has the best information on the costs of providing the individual services.[11] If the regulator has the best information regarding the cost of supply at each disaggregated level then it should make all pricing decisions for standard retailers. That is, if the regulator has the best information on the costs of supply it should determine both the level of overall cost recovery *and* the details of how those costs are recovered from individual services.

In order for a regulator to be better informed about disaggregated pricing than a standard retailer it is necessary that:

1. the regulator can better forecast costs at the beginning of the regulatory period than the standard retailer;
2. actual costs do not materially deviate from those regulatory forecasts over the three year regulatory period (or there is an automatic pass-through mechanism for such deviations);
3. the regulator can adequately differentiate between marginal versus fixed/common retailing costs and has adequate understanding of demand elasticities to determine the efficient allocation of recovery of those costs across services.

We are unaware of reasons to believe that any of the conditions 1 to 3 above will hold. On the contrary, it appears reasonable to assume the opposite on the basis that:

- Retailers' day to day operations require them to understand their costs in a much more detailed way than a regulator can be expected to do so.
  - Indeed, it is a general presumption of regulation that regulated businesses have better cost information than regulators. It would be highly unusual to presume that a regulator had better forecasts of individual cost components than a regulated business.
- Even if the regulator did know best at the time of the regulatory decision, this would almost certainly not be true as the costs vary over the life of the regulatory period.

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[11] More accurately, the regulator should make these decisions when it has the best information on the **marginal** costs of supplying each service **and**, to the extent that there are fixed costs that need to be recovered, the elasticity of demand for each service.

- For example, while the regulator may have derived the best possible three year forecast the cost of energy on Integral's non-TOU Default Domestic tariff (which accounts for 68% of revenue) it is likely that the actual cost faced by Integral will differ from this during the period. This may be because wholesale prices deviate from forecast or because the average load profile for customers on this tariff deviates from forecasts.

- Regulators have little or no information on demand elasticities across individual services. This is despite the fact that an understanding of demand elasticities is required to determine how to most efficiently recover common costs across the retailers' customer base.

On the basis of the above observations we consider that any FoPC should focus on controlling monopoly pricing at the aggregate retail level and should not impose a disaggregated pricing strategy on standard retailers (ie, should not decide how retailers recover costs across their customer base).

3.2.1. Implications for the current FoPC

The current FoPC imposes a 'target R' at the level of the individual tariff. This means that standard retailers cannot increase aggregate revenue for a tariff if that results in the tariff 'over-recovering' costs - based on forecasts of marginal costs estimated by IPART prior to the beginning of the current regulatory period.[12] As described above, we believe that this will only be appropriate if the regulator's historic forecasts are better estimates than retailers' contemporary expectations.

There is a valid argument that, for the 2004/05-2006/07 regulatory period, this assumption was approximately true. This reflects the fact that the prices paid for energy by retailers were determined under the ETEF, with some linkage to long run marginal cost and IPART did know with considerable certainty what these prices would be. However, with the roll-off of ETEF this is no longer true and the prices paid for energy by standard retailers are much less certain going forward. In considering these issues the Electric Energy Market Competition Task Force has reported to the US Congress that:

> *'Experience within the profiled states shows that approximating the competitive price is not an easy task. Not only does the competitive price change when prices of inputs change, but the price also acts as an investment signal for new generation. The competitive price can quickly and dramatically move. Over the past several years, the initial fixed discounts for POLR [provider of last resort] service have resulted in POLR service prices that are below market prices or occasionally above market prices, but never at the market price for long. When the POLR prices are below competitive levels, even efficient alternative suppliers cannot profit by entering or continuing to*

12 Subject to certain circumstances where retailers can demonstrate to IPART that there are cross-subsidies *within* over-recovering tariffs.

> *serve retail customers. Firms with the POLR obligation can become financially distressed, as they did in California during its energy crisis.'*[13]

The greater uncertainty surrounding future costs increases the probability of regulatory forecasting error in estimating the cost of individual tariff elements - and therefore the 'target R' for each tariff. The one certainty going forward is that, whatever marginal cost estimates are used, applying them to individual tariffs will result in some tariffs being allocated inappropriately higher costs and some inappropriately lower costs relative to the true underlying costs. Forcing standard retailers to reflect these allocations in their pricing strategies will compound this error.

To illustrate this issue, consider a simplified example where a retailer has only two tariffs - residential non-TOU and commercial non-TOU. For simplicity, assume that both have the same number of customers and the same amount of energy consumed. Further, imagine that the true marginal costs and the regulators' estimates of marginal cost are as per the below table.

Table 3.1
Numerical Illustration

	True marginal cost	Regulated estimate	Quantities	Target R per tariff	True R per tariff	Error in Target R
Commercial customers						
Customers	80	60	10	600	800	
Energy ($/MWh)	10	10	100	1000	1000	
Total				1600	1800	13%
Residential customers						
Customers	40	60	10	600	400	
Energy ($/MWh)	10	10	100	1000	1000	
Total ($)				1600	1400	-13%
Aggregate						
Customers	60	60	20	1200	1200	
Energy (average $/MWh)	10	10	200	2000	2000	
Total ($)				3200	3200	0%

In the example described above, the regulator sets the same cost per customer and per MWh for both commercial and residential customers (just as IPART did in the last review). However, in our example, the cost per customer is higher for commercial customers. (This

[13] Electric Energy Market Competition Task Force, *Report To Congress On Competition In The Wholesale And Retail Markets For Electric Energy – Draft*, 5 June 2006, pages 90-91.

might be true if commercial customers require greater personalised interaction.) On average the regulator has estimated the correct aggregate retail cost of $3,200 but this is comprised of a 13% over-estimate of costs for residential customers and an offsetting 13% under-estimate of costs for commercial customers.

If the FoPC allows the retailer to determine how it recovers the aggregate cost of $3,200 then the retailer has an incentive to recover this in line with its own estimates of actual retail costs (ie, by setting cost reflective tariffs). This would involve recovering $1,400 from residential customers and $1,800 from commercial customers. Any other pricing strategy will leave the retailer exposed to poaching of customers from the tariff that is above true cost reflective levels. By contrast, if the regulatory FoPC forces the retailer to recover a maximum of $1,600 from each tariff then the retailer is placed in an untenable position. The retailer will have a 13% shortfall of revenues from commercial customers relative to cost and must choose between:

- trying to limit the short run impact of this shortfall by pricing at the allowed level for residential customers - even though this exposes the retailer to long term residential customers loss (because it involves pricing at 13% above the cost of supplying residential customers); or

- trying to protect its residential customer base by pricing to residential customers below the amount allowed by the regulator.

This example illustrates why, in a contestable market, imposing restrictions on individual prices/revenues as well as aggregate prices/revenues dramatically increases the scope for, and potential costs of, regulatory error. This is because, in a contestable market, the constraints on the retailer are not just regulatory but also competitive. As a result, simplifications in the cost modelling that lead to under-estimates of costs for some tariffs and over-estimates for other tariffs *do not* cancel out. In this situation the business under-recovers on the tariff where costs have been under-estimated and is prevented by competition from over-recovering on other tariffs.

This creates an asymmetry of impact of regulatory error. A regulatory error that under-estimates of costs for a tariff results in a windfall loss equal to the value of the under-estimate. By contrast, a regulatory error that over-estimates costs on another tariff does not result in a windfall gain of the same magnitude as competition prevents the retailer from pricing at the allowed regulated level.

If, instead, the FoPC is only applied at the aggregate level then simplifying regulated cost modelling assumptions (such as in the above example) is costless. So long as the aggregate level of costs is estimated accurately the retailer can choose to recover those costs in accordance with its perceptions of actual costs.

Conclusion 3.1 - Asymmetric Cost of Error

In the presence of contestable markets, individual tariff regulation creates an asymmetrical cost of regulatory error. Losses as a result of under-estimates of costs on some tariffs are, due to the threat of competition, not offset by over-estimates of costs on other tariffs.

This asymmetry means that, if regulation at the level of individual tariffs is retained, there are at least three important implications for the cost modelling process. First, much greater effort must go into the modelling of how costs vary across tariffs. This reflects the fact that any arbitrary allocations of costs to individual tariffs will inevitable impose losses on the retailer (because it inevitably results in some tariff revenues being set below costs and some above costs).

Secondly, additional margins must be built into all cost estimates in order to negate the asymmetry discussed above. To see why, note that applying the FoPC at the level of aggregate tariffs only means that the retailer can still recover its efficient costs even when the regulator's cost modelling under-estimates costs on half of all tariffs and over-estimates costs by the same amount on all other tariffs. This is not true if the FoPC is applied at the level of individual tariffs for the reasons discussed above. Under regulation of individual tariffs, in order to avoid imposing overall losses on standard retailers the regulator must be close to certain that its cost modelling does not under-estimate costs on any individual tariffs. In order to do this the cost modelling must build in higher margins than it needs to under a FoPC that only regulates at the aggregate tariff level.

Thirdly, irrespective of how intensive the regulator's cost modelling is, a full distribution of costs to individual tariffs will always involve an arbitrary element. This is because not all retailing costs are marginal but rather some costs are common across customers and across tariffs. Examples of such costs include the costs associated with billing systems, corporate overheads and the costs associated with corporate branding. Even energy costs can have an element of common costs to the extent that diversification of a retailer's customer base can lower the costs of reaching a given level of contract cover.

In the presence of such common costs there is no economically 'correct' allocation of costs between tariffs. The most efficient way to recover common costs depends on a knowledge of the demand elasticity of customers - with common costs being efficiently recovered from services/tariffs that have relatively low elasticity of demand. However, a FoPC applied at the individual tariff level allocates common costs in an inevitably arbitrary manner across tariffs. In general, this means a uniform mark-up on marginal cost is imposed on standard retailers by the FoPC.

This is important in a contestable market place as competitors will be able to compete for some customers on the basis of marginal costs while recovering common costs through a higher margin charged to other customers. If standard retailers can not respond in kind to such a strategy (because regulation imposes a uniform mark-up on common costs) then they will tend lose those customers targeted by competitors - with the effect that they lose scale and average costs rise across the remainder of the customer base. A FoPC that imposes a uniform mark-up on marginal cost leaves regulated retailers at a competitive disadvantage to unregulated retailers - to the long-term detriment of those customers that remain on regulated tariffs.

Conclusions 3.2 - Implications for Cost Modelling

a. A FoPC that applies at the individual tariff level requires the regulator to invest more heavily in ensuring cost differences across tariffs are captured. (Even then, it is certain that these cost estimates will quickly become dated as the regulatory period wears on.)

b. The asymmetric cost of error under this FoPC means that the cost modelling must incorporate greater margins to protect against regulatory error.

c. The existence of common costs means that any regulatory full allocation of costs down to the individual tariff level is inevitably arbitrary. Consequently, any FoPC applied at the individual tariff level puts standard retailers at a competitive disadvantage.

In relation to the above recommendation it is worth noting that the in the 2004/05-2006/07 regulatory period IPART assumed a single average cost per customer irrespective of whether that customer was residential or commercial. It appears unlikely to us that this is accurate. It is also worth noting that IPART applied the same 6.37 c/kWh[14] energy cost for: all of Integral's non-TOU tariffs (residential and commercial) and for peak and shoulder periods in ToU tariffs. As a matter of logic, the peak cost of energy on ToU tariffs should be higher than the average cost of energy on non-ToU tariffs. However, this was not the case in the last determination - with the result that the 'Target R' for these tariffs is likely to be below cost.

It is also important to consider the implications under each FoPC of regulatory error in estimating aggregate costs. If the regulator materially over-estimates retail costs for every tariff, and hence over-estimates aggregate retail costs, then standard retailers will be primarily constrained by the effectiveness of competition from monopoly pricing to their customers. In this scenario there is little difference between a FoPC that is applied at the aggregate or the individual tariff level.

By contrast, if the regulator materially under-estimates retail costs for every tariff, and hence under-estimates aggregate retail costs, then the impact of this error on retailers will be magnified under individual tariff regulation. In this scenario, the loss minimising strategy for the regulated retailer (and the most efficient for society) is to lower prices most where demand is relatively inelastic and leave prices high where demand is relatively elastic. In so doing, the retailer mitigates the (inefficient) expansion in demand as a result of regulation forcing below cost pricing. However, a FoPC applied at the individual tariff level may prevent such a strategy being fully pursued to the extent that it forces uniform below-cost pricing across all services (ie, irrespective of elasticity of demand).

Conclusion 3.3 - Individual tariff regulation is worse even when all costs are underestimated

Individual tariff regulation is likely to inhibit the most efficient response to a uniform underestimate of costs by the regulator.

The following table summarises the performance of a weighted average price cap applied at the level of aggregate tariffs against the six criteria established in Section 1.

[14] In 2004/05 dollars. See table 3.3 on page 12 of IPART's Final Report and Determination.

Table 3.2
Summary of regulatory objectives

Objective	Attainment through weighted average price cap
1. Prevents monopoly prices	Yes. Performs as well as any other intrusive FoPC
2. Allows recovery of efficient costs	Performs better than a FoPC applied at the individual tariff level
3. Promotes competition	Because it allows greater confidence of cost recovery it also is more likely to promote competition (as below cost pricing inhibits entry)
4. Prevents 'excessive' price shocks	Depends on whether side constraints used in conjunction.
5. Minimises compliance costs	Performs as well as any other intrusive FoPC.
6. Regulatory precedent	Yes. Regulatory precedent for this approach in the ACT and, we suspect, Victoria (see Appendix C)

3.3. Preventing Excessive Price Shocks

The most fundamental impediment to tariff rebalancing to cost reflective levels and tariff rationalisation within the current regulatory period has been the side constraint placed on annual increases in individual tariffs. This constraint required that:

> *'the annual bill (excluding miscellaneous charges) for any customer must not increase by more than $35 excluding GST or the percentage change in CPI+5% (whichever is greater) for the same pattern and level of consumption.'*[15]

IPART imposed this constraint as an additional consumer protects against 'unacceptable price increases.' This requirement was made in line with the terms of reference for that review which required IPART to recognise customer's ability to adjust to new prices as well as the need for a 'smooth transition' to full cost recovery.[16]

While this period has allowed some tariffs to transition to a more cost reflective basis, this is not true of all tariffs. As the side constraint was applied to customers' total bill (ie, including both network and retail charges), retailers have be constrained in their ability to rebalance tariffs. This is because network businesses have been permitted to increase their annual tariffs by up to $30 per bill leaving a marginal increase of only $5 for retailers (where $35 is greater than CPI + 5%).

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[15] IPART, NSW Electricity Regulated Retail Tariffs 2004/05 to 2006/07 Final Report and Determination, June 2004, page 18.

[16] Letter from Minister for Energy and Utilities to IPART regarding *Review of regulated retail tariffs and charges for electricity to 2007*, 16 September 2003, page 2.

It may be that this retail determination requires substantial price increases to reach new estimates of cost reflective levels. If this is the case then the imposition side constraints may stymie the achievement of criterion 2 (cost reflectivity).

It is important to also note that it is unclear what constitutes an 'excessive' price increase for an individual customer. On one view, an increase in prices that moves those prices closer to cost, but not above cost, is not excessive - irrespective of how large it is. On this view there is a limited rationale for side constraints, given that above cost pricing to individual customers will expose the retailer to switching by those customers it is reasonable to question the need for any side constraints. Moreover, side constraints impose restrictions in tariff reform that can prevent the achievement of full cost recovery (criteria 2 above).

We are sympathetic to the view expressed above and recommend that no side constraints be imposed. However, we recognise that large price increases for individual customers, even if it is simply the rapid unwinding of below cost pricing, can create community tensions. If side constraints are imposed to address this, we recommend that their level be calibrated not to unduly delay movements in prices to approximately cost reflective levels.

3.4. Pass Through Mechanisms and Frequency of Resets

As the point of interaction between end use customers and all upstream electricity supply chain participants, retailers are susceptible to any and all variations in electricity supply costs. While many of these costs can be reasonably foreseen,[17] as this review attempts to do, there remain instances where retailers can be exposed to cost/price squeeze risks that are beyond their control. This is particularly the case where retailers are restricted in their price adjustments as occurs in the current approach to regulated retail tariffs.

There is no reason why such risks should be borne by retailers unless they are compensated. In recognition of this fact, some regulators include pass through mechanisms in the retail price controls for the periodic pass through of:

- unforeseen or uncertain costs; and
- wholesale energy prices.

3.4.1. Uncertain and unforeseen costs

In recognition of the need to ensure the financial viability of its National retailer is not threatened by uncertain or unforeseen cost pressures that are beyond the retailer's control, the Irish Commission for Energy Regulation (CER) has allowed pass through of such costs in regulated retail prices. In its 2005 retail price direction decision the CER included a U_t factor in its price control for the pass through of uncertain costs. The CER identify that:

> *'Uncertain costs are defined as those that could not reasonably be foreseen by the business and comprise elements such as:*
> *• Single Electricity Market related costs and other costs related to market opening*

[17] For example regulated network costs and certain fixed asset costs

> *• Changes in legislation or regulation that impose a cost or provide a benefit to PES [Public Electricity Supply]*
> *• Restructuring costs driven by changes in legislation'*[18]

In the ACT, ActewAGL (under the current and about to expire form of regulation) is able to raise prices faster than CPI+X if it can "demonstrate"[19] that the price increase is due to:

- wholesale market conditions affecting ActewAGL's proposed benchmark price;
- the form of market arrangements adopted in the ACT market;
- NEMMCO fees and charges;
- MRETS/greenhouse levies;
- FRC customer churn rates (which give rise to FRC cost recovery different to forecast levels);
- network tariff variations; and
- other fees, taxes and imposts.

We also understand that there are **no** side constraints applied to the tariff basket.

In the current NSW legislative and regulatory setting there are a number of future changes which can be expected to impact retailers during the next price control period. Many of these changes are too early in their conception to enable reasonable estimation of the likely cost impost on retailers. Such costs may best be accounted for via a pass through mechanism of the form adopted by the CER or the ICRC.

For example, the COAG agreement to roll out time-of-use meters may impose unforseen costs on retailers. These may take the form of additional data processing costs through to the costs of paying time of use network tariffs whilst being required to sustain customers on regulated tariffs where the various peak, off-peak and shoulder periods may not align.

3.4.2. Energy costs

In addition to unforeseen or uncertain cost pass throughs, many regulators also include a specific periodic pass through mechanism for changes in the price of wholesale energy. This is the case in Ireland where the CER allows retailers to recover annually changes in the price of wholesale energy. This approach is also adopted in several states of the US including Maine, Rhode Island, New York and Texas where prices for provider of last resort (POLR) service have been regularly adjusted to reflect changes in wholesale prices.

For example, the current US Electric Energy Market Competition Task Force review of competition in the wholesale and retail markets for electric energy has identified that:

> *'Some states have separated fuel costs from other cost components, because fuel costs have been more volatile than other input prices - they are the largest*

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18 CER, 2006-2010 ESB Price Control Review – Public Electricity Supply - A Consultation Paper, 26 July 2005, page 21.

19 Although rules for how these issues can be demonstrated are not well developed (at least in a public setting).

> *variable cost component, and can be calculated for each type of generation unit, based on public information.'*[20]

Many regulators have allowed more frequent adjustment for wholesale energy costs due to their higher level of volatility relative to other supply costs, and due to the ability to transparently identify these costs from generation markets in order to provide effective and independent cost assessments and allowances in as close as possible to real-time regulatory adjustment. This is necessary to support market entry and retail competition, but also to protect the financial viability of incumbent retailers who are required to provide energy retailing services at regulated rates.

The consequences of capping retail prices and not allowing regular adjustment for changes in wholesale energy prices can be dire as demonstrated by the 2000 to 2001 Californian energy crisis and subsequent suspension of retail competition (see Box 3.1).

Box 3.1
Californian Energy Crisis - wholesale energy price squeeze

Between spring 2000 and spring 2001, the US state of California experienced high natural gas prices along with a constrained transmission system and widespread generation shortages. During this period, wholesale prices increased substantially with future prices generally ranging between $350-$550 per MWh and peaking at $750 per MWh in April 2001.[21]

State law capped residential POLR prices at levels below the market wholesale energy price paid by retailers. One of California's large private retailers, PE&G, declared bankruptcy because it could not increase its retail prices in order to recover the high wholesale energy prices it faced. The state government was forced to purchase electricity supply on behalf of two of the three privately owned retailers operating in California. In 2001 the government spent USD $10.7 billion purchasing energy in the spot market to meet daily consumption demand. The state government eventually suspended retail competition for most customers to allow it to maintain sufficient energy supply at affordable prices and entered into USD $43 billion in long-term energy purchase contracts out to 2010. The suspension of retail competition continues to this day.

The US Electric Energy Market Competition Task Force review has identified that the establishment of effective retail competition has been more successful in those states that have permitted periodic price adjustment for changes in wholesale energy prices. In particular it is has found that Texas, which allows adjustments twice a year for changes in the energy cost element of regulated retail prices, has been successful in maintaining regulated prices in close proximity to market prices, thereby protecting the financial viability of

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20 Electric Energy Market Competition Task Force, *Report To Congress On Competition In The Wholesale And Retail Markets For Electric Energy – Draft*, 5 June 2006, pages 87-88.

21 Electric Energy Market Competition Task Force, *Report To Congress On Competition In The Wholesale And Retail Markets For Electric Energy – Draft*, 5 June 2006, page 76

retailers providing regulated services, whilst also facilitating market entry by alternative competitive retail suppliers.[22]

3.4.3. Implications for price control design

3.4.3.1. Uncertain or unforeseen costs

Given that there are no valid efficiency or equity reasons for providers of regulated retail tariffs to bear additional price/cost squeeze risk associated with capped prices, it is appropriate that allowance be made for the pass through of substantial unforseen or uncertain costs. Such costs could be pass through on an ‘as needs’ basis during the standard price adjustment process. It is appropriate that IPART retain the role of reviewing such costs prior to their pass through in order to ensure that these have been efficiently incurred and are attributable only to a relevant unforeseen or uncertain event. It would also be appropriate that a framework of criteria for assessing such pass through events be consulted on and developed as part of this review.

The following costs may be considered as unforseen costs in the contact of pass through. Where these costs are passed through they should be passed through ‘out-side’ of any side constraints placed on annual increases in retailers’ regulated retail tariffs.

- Changes in the way or rate at which a government imposed tax, fee, levy or charge (relevant tax) is calculated, or the imposition of a new tax to the extent that the change (such as the introduction of carbon tax), removal or imposition results in a change in the amount a retailer is required to pay or is taken to pay (whether directly or under any contract) by way of relevant taxes.

- Insurance events including:

  – changes in the availability and extent of cover that result in material increases in the cost of insurance relative to the forecast included in the retail operating expense;

  – payment by Integral of a deductible premium in connection with a claim under an insurance policy; or

- Other (self insurance) events being any event which is outside Integral's prudently determined risk management policies and is not insured and causes Integral to suffer material loss or damage.

- Regulatory events incorporating changes to the scope, standard or risk of retail services as a result of changes to the National Electricity Rules, decisions by NECA, NEMMCO, the Tribunal, the NSW Government, or the courts or changes to legislation (such as environmental certificate requirements), regulation, licence conditions or other legally binding instruments that retailers are required to comply with and which result in retailers incurring materially higher or lower costs associated with the retail services than it would have incurred but for that change.

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[22] Electric Energy Market Competition Task Force, *Report To Congress On Competition In The Wholesale And Retail Markets For Electric Energy – Draft*, 5 June 2006, pages 87-88.

- Distribution loss factors, where these are materially higher or lower than allowed for in determined regulated retail costs.

Regulatory precedent for such pass throughs can be found in a number of Australian jurisdictions including the ACT and SA. Discussion of these can be found in section 3.4.1 and Appendix C.

3.4.3.2. Energy costs

Given the substantial share of retail customer bills attributable to the wholesale price of energy, it is important that any approach to retail tariff regulation affords retailer sufficient flexibility to adjust their prices to pass on these changes to retail customers. Where this is not the case, regulated retail prices have the potential to damage the financial viability of regulated retail providers whilst also deterring competitive market entry.

Given the uncertain nature of energy prices, this flexibility may best be achieved via periodic pass through of movements in wholesale energy prices (or the drivers thereof) as adopted by various international regulators. This is consistent with the findings of the US Electric Energy Market Competition Task Force that

> *'... design that adjusts the retail electricity price for changes in the prices of fuels used by marginal generators makes a better proxy for the market price than one that is fixed.'*[23]

The more frequent such adjustment is applied, the more closely regulated retail tariffs can be expected to approximate competitive market prices and, by implication, also approximate the actual cost of supply. One option to achieve periodic adjustment for changes in wholesale energy costs is considered in the Box 3.2.

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[23] Electric Energy Market Competition Task Force, *Report To Congress On Competition In The Wholesale And Retail Markets For Electric Energy – Draft*, 5 June 2006, pages 91.

Box 3.2
Sample of wholesale energy cost pass through

Regulating retail tariffs with regard to retail costs necessarily involves estimating the price of wholesale energy for the ensuing pricing or regulatory period (be that six months, one year or three years). Where these estimates vary substantially from the actual price experienced in the wholesale market, regulated retail prices will vary from competitive retail market prices, with regulated retailers potentially experiencing either windfall gains or losses.

One means of limiting the divergence between the estimated wholesale energy costs included in regulated retail tariffs and the actual wholesale price is to have a mechanism for periodic energy price adjustment. For example, one possible mechanism would involve IPART forecasting the average wholesale cost of energy (based on the forecast load profile) for the regulatory period and then 'cross-checking' this with the actual cost of energy during the review. If material divergences exist, say more than 5%,[24] this could trigger an increase/decrease in allowed energy costs.

If no pass through mechanism is introduced then retailers should be compensated for bearing the risk associated with fixed retail prices but variable energy costs (ie, bearing the risk that they will suffer the same fate as retailers in California in 2000/01).

3.4.4. Frequency of resets

When establishing the FoPC it is necessary to determine the frequency of pricing resets (ie, calibrations of estimated cost and forecast revenue). Under IPART's current approach to retail tariff regulation, these resets occur annually when the target revenue is recalculated for each tariff.

The alternative to this approach is one where a price path is set at the commencement of the regulatory period and is not revisited until the time of the next regulatory review (in this case three years). This second approach is the approach commonly adopted for network tariff regulation, whereby resets are applied every five years.

IPART's current approach (effectively recalibrating "X" every year) has advantages where quantities are hard to forecast and where unit prices do not perfectly reflect marginal costs. We see no compelling reason to move from the current approach.

3.5. Tariff Quantities

In Australia, different quantities are used as weights in price cap regulation. The common approach to network tariff regulation is to employ audited historic tariff quantities from two years prior for the purpose of assessing price control compliance. For retail price regulation, IPART currently use historic and estimated tariff quantities from the preceding year to assess target revenue compliance. While, in contrast, ESCOSA use forecasts of tariff quantities for the year in which the prices are to apply.

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[24] This is the trigger figure used in Texas. For example, see http://www.puc.state.tx.us/electric/reports/scope/2005/2005scope_elec.pdf

Table 3.3
Examples of price control tariff quantities

Regulator / Jurisdiction	Tariff	Quantity measure*
IPART / NSW	Retail	Historic and estimate (year t-1)
ESCOSA / SA	Retail	Forecast (year t)
IPART / NSW	Network	Historic (year t-2)
ESC / Victoria	Distribution	Historic (year t-2)
ESC / Victoria	Transmission	Forecast, estimate and historic (years t, t-1 and t-2)^

*Notes: * Where 't' is the year in which the tariffs being approved will be applied.*
^ annual transmission tariffs are approved based on forecast tariff quantities while estimated and audited historic tariff quantities are used in determining the correction factor component of the revenue control.

A consequence of the IPART and ESCOSA approaches to retail regulation are that the tariff quantities used to assess compliance are not audited. The pertinent question then is whether it matters that tariff quantities are not audited for the purpose of retail tariff regulation. To answer this, one must consider the differences between the regulatory approach to network tariffs (which use audited quantities) and retail tariffs (which use estimated or forecast non-audited quantities).

The fundamental difference is the basis of cost estimation inherent in the regulated price path. Specifically:

- network tariff regulation applies a specified annual movement based on expected costs (which take into account expected demand); while
- retail tariff regulation attempts to calculate the cost requirement each year and then allows price movement to achieve revenues sufficient to recover this cost requirement.

Network tariff regulation involves constructing a building block cost assessment over the life of the regulatory period, and then employs forecast quantities to calibrate annual price change required to align the NPV of these costs with the NPV of forecast revenues over the period. As this price path is aligned taking into account demand expectations, it is sufficient for the annual price movements rely upon lagged quantities. This is because these quantities are being used to assess allowed movement based on a discounted total period cost assessment.

In contrast, retail price regulation of the form adopted by IPART, effectively performs an annual retail cost assessment (instead of applying an allowed movement based on a smoothed price path over the period). This means that the cost assessment has not yet taken into account forecast demand. In order to ensure retailers are permitted sufficient revenues to cover their costs, it is necessary that the tariff quantities used are a reasonable approximation to those anticipated in the coming year.

In this regard, it will be preferable to use forecast tariff quantities for the year in which the tariffs are to apply. This ensures the revenue allowance is correctly calibrated to return revenues sufficient to cover the expected costs. Consequently, retail tariffs approved on the basis of forecast quantities can be expected to be more cost reflective than those which use historic quantities.

4. Interaction of FoPC and policy directions

4.1. Demand Management

The terms of reference for IPART's current review require the Tribunal to have regard to the impact of its determination on demand management. In this regard, it is useful to examine how various forms of price control will impact retailers' ability to apply demand management price signalling, and their incentives for demand management via energy conservation measures.

The **current** FoPC on regulated retail tariffs is a weighted average price cap applied to individual tariffs (see section 2). Under this form of price control, retailers have an incentive to lower costs as they are permitted to retain any difference between the revenues earned on a given tariff and the cost of providing service on that tariff.

At the retail level a weighted average price cap, be it applied to individual tariffs (as at present) or to aggregate tariffs (as proposed) does not undermine incentives for demand management. At a retail level, retailers' marginal costs can be expected to closely reflect marginal prices. This is because the more energy a retailer sells, the more energy it has to purchase in the wholesale market. Thus, higher volumes of energy purchases do not automatically translate into higher retail profits. This means that even under a weighted average price cap, a rational retailer will not attempt to increase customer demand as this will not be profitable.

This demand management outcome contrasts to the arrangements at a network level. At the network level, a weighted average price cap may be considered to be counter-productive to demand management measures. This is because network operators have average cost structures which tend to fall as the volume of consumption increases (assuming these demand increases are consistent across all times, and not just at peak periods). Thus, under a weighted average price cap, a network operator may have incentive to maximise consumption in order to maximise its revenues and retained profits.

In recognition of this potential tension at the network level, IPART has included a 'D factor' in its network price control to allow for, and motivate, demand management activities at the network level.

It is therefore important that consideration of demand management and retail pricing does not confuse the different incentives and cost structures faced by these two different participants in the energy supply chain.

In the context of retail pricing, demand management is more likely to be impeded by any side constraints that restrict retailers' ability to rebalance tariffs. Such constraints will limit retailers' ability to pass through to customers demand management price signalling such as increased application of time-of-use pricing by network operators or even critical peak pricing initiatives (at both network and retail levels).

In this regard, it is consistent with the terms of reference that IPART abolish the current CPI+5% or $35 constraint on individual tariffs.

4.2. Tariff rationalisation

There are currently numerous obsolete regulated retail tariffs currently levied in NSW. These obsolete tariffs tend to be constrained at below cost reflective levels and indeed below IPART's own target revenue estimates. Consequently, the terms of reference for IPART's current review require that regulated retail tariffs are cost reflective and that the form of regulation adopted allows further rationalisation of regulated retail tariffs.

In this regard, it will be preferable to adopt the price monitoring approach proposed in section 2 as this will afford retailers the flexibility to vary these obsolete tariffs or remove them in an efficient manner.

Alternatively, the 'opt-in' regulated retail tariff approach discussed in IPART's Issues Paper[25] may be an effective means of allowing retailers to abolish obsolete tariffs whilst retaining the consumer protections inherent in the default regulated retail tariffs.

Under such an approach customers on obsolete regulated retail tariffs may be approached and offered the opportunity to take up a competitive market offer or o switch to a default regulated retail tariff. The adoption of such a regulatory approach would likely necessitate an education campaign whereby retails would be required to provide minimum information to those customers being switched off obsolete tariffs.

It should be noted that this 'opt-in' approach can be adopted regardless of the FoPC that is adopted. That is, an 'opt-in' approach may be used in conjunction with a weighted average price cap. Where price monitoring is adopted, an 'opt in' approach would be redundant.

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[25] Review of Regulated Retail Tariffs and Charges for Electricity 2007 to 2010, Issues Paper, July 2006, page 12.

5. Mathematical Description of Proposed FoPC

IPART's current form of price control can be described as a weighted average price cap which:

- is applied at the level of each individual tariff - due to the overarching requirement to constrain individual tariffs to their respective target level;
- uses historic and estimated quantities from the preceding year to test compliance; and
- calculates a new X-factor each year.

Thus, while IPART presents its current form of regulation as a revenue target, it is nonetheless a variant of weighted average price cap (albeit with "X" reset each year).

Each year IPART uses predetermined estimates of cost variables (per customer and per kWh) and historic quantities to determine the 'retail cost' on a specific tariff. IPART then multiplies the same quantities by proposed retail prices (net of network prices) for that specific tariff to derive an estimated retail revenue on that tariff. IPART then approves the price increase if its estimate of revenues is less than its estimate of retail cost. That is, prices are approved if, each year:

$\sum_i C^i \cdot q_{t-1}^i \geq \sum_i P_t^i \cdot q_{t-1}^i$; where C^i is IPART's (unchanging) estimate of the unit cost of supplying q^i.

Formulaically, this is identical to IPART specifying that weighted average price on each tariff (using q^i_{t-1} as the weights) must not increase by more than X this year - where X is re-determined each year as:

$$\frac{\sum_i C^i \cdot q_{t-1}^i}{\sum_i P_{t-1}^i \cdot q_{t-1}^i} = X \geq \frac{\sum_i P_t^i \cdot q_{t-1}^i}{\sum_i P_{t-1}^i \cdot q_{t-1}^i}$$

Specifying the current form of regulation in this manner allows us to identify precisely the minor change required to give effect to our proposed form of price control. The *minimalist* change required to achieve *average* tariff regulation (rather than specific tariff regulation) based on *forecast quantities* (rather then historic quantities) is to introduce a weighted average price cap for all tariffs where X is reset each year as:

$$X = \frac{\sum_j \sum_i C^{ij} \cdot q_t^{ij}}{\sum_j \sum_i P_{t-1}^{ij} \cdot q_t^{ij}}$$

The only difference between this approach and the current approach is that:

- the current form of price control respecifies a new X-factor each year for the weighted average increase in prices *on each tariff* and requires tariffs to be constrained to their target level; while
- the above form of price control respecifies a new X-factor each year for the weighted average increase in prices *across all tariffs*; and
- the current form of price control uses *historic and estimated tariff quantities* from the *preceding year* to determine 'retail cost' for the ensuing year; while
- the above form of price control uses the *latest forecast tariff quantities* for the *ensuing year* to determine 'retail cost' for that year.

The complete mathematical representation of the proposed WAPC is therefore:

$$\frac{\sum_j \sum_i C_t^{ij} \cdot q_t^{ij}}{\sum_j \sum_i P_{t-1}^{ij} \cdot q_t^{ij}} = X \geq \frac{\sum_j \sum_i P_t^{ij} \cdot q_t^{ij}}{\sum_j \sum_i P_{t-1}^{ij} \cdot q_t^{ij}}$$

The target revenue component of the above equation will be calculated based on the unit cost estimates (C_t^{ij}). These are in turn determined by IPART at the beginning of the review and then amended for any specified pass through allowances (eg, for CPI or other factors). The target revenue will therefore provide for the total fixed and variable retail operating costs, retail margin and expected wholesale energy costs across all regulated tariffs.

Appendix A. Alternative regulatory arrangements

Table A.1
Summary of Conclusions Regarding Alternative Regulatory Arrangements

Lower number reflects superior contribution towards objective

Objective / Form	**Objective 1 Limit monopoly prices**		**Objective 2 Allow cost recovery**		**Objective 3 Promote competition**		**Objective 4 Limit inappropriate price shocks**		**Objective 5 Minimise direct costs**	
Current arrangements (WAPC at individual tariff level, binding side constraints)	3	'Cost reflectivity' on a per tariff basis maximises the cost of errors if IPART's estimate of cost structure is wrong.	4	Strict side constraints limit cost recovery even if IPART's estimate of costs correct (especially if new determination raises compensation for retail costs)	4	Side constraints limit cost recovery and slow competition. Regulation of individual tariffs reduce Integral's flexibility to reflect its retail cost structure.	4	Assessment requires definition of 'inappropriate' price shocks. In our view the current side controls limit appropriate price shocks.	5	Side constraints increase compliance and regulatory costs.
Relative tariff regulation	3	Only effective with substantial pre-existing competitive supply	1	Provided regulated tariffs above competitive tariffs.	4	May discourage standard retailers from making comp offerings.	Na	Depends on whether combined with side controls	3	Requires identification and monitoring of 'comparable offerings'
WAPC at the aggregate tariff level	2	Effective control on monopoly revenues provided cost estimates accurate	1	Apart from side constraints, no constraint on recovering estimate of efficient costs	1	Assuming new entrant costs and are not aggressively estimated	na	Depends on whether combined with side controls	1	Minimises compliance costs.
Revenue/average tariff regulation	2	Effective control on monopoly revenues provided cost estimates accurate	1	Apart from side constraints, no constraint on recovering estimate of efficient costs	1	Assuming new entrant costs and are not aggressively estimated	na	Depends on whether combined with side controls	1	Minimises compliance costs.
Relaxed price movement limits (under current and/or average tariff regulation)	NA	Side controls do not control aggregate revenues	1	Improved ability to recover costs due to pricing flexibility.	1	Improved opportunities for competition.	1	Current arrangements restrict appropriate price shocks.	2	Relaxed limits reduce the intrusiveness of regulation.
Price monitoring	1	Restricts monopoly pricing when it is obvious.	1	Should allow retailers to justify prices on cost basis.	1	Will encourage comp if it allows cost reflective tariffs.	Na	Depends on whether combined with side controls	1	Hands-off approach reduces costs.

Appendix B. Price monitoring case studies

B.1. Airports

Prior to 2002 airports were subject to industry-specific price regulation under the *Airports Act 1996*. Following the Productivity Commission's review of the regulation of airport services, this was replaced by a 'light-handed' price monitoring framework. The monitoring of airport prices is carried out within the generic provisions of the *Prices Surveillance Act 1983*. The ACCC is the independent regulator responsible for overseeing airports. It monitors the prices, costs and profits relating to aeronautical and aeronautical-related services of the relevant airports, publishing its findings annually.[26]

Prices are monitored by reference to a clearly articulated set of pricing principles.[27] Provided airports comply with these principles, they can set whatever prices they deem appropriate. However, an airport that deviates from these principles runs the risk having price controls re-imposed. The practical effect of these arrangements is that, whilst not regulated, airports are subject to an ongoing *threat* of regulation. These arrangements have been in effect from 1 July 2002, with an independent review scheduled to take place in 2007 to ascertain the need for future airport price regulation.

The Federal Government considered that 'lighter-handed' regulation of airports was appropriate since airport operators face strong commercial incentives to increase passenger throughput, and had facilitated the entry of new airlines to the market.[28] In implementing the new price monitoring arrangements, Treasurer Peter Costello stated:[29]

> *'[A]irport operators have strong commercial incentives to increase passenger throughput, and have facilitated the entry of new airlines to the market ... A lighter-handed approach provides greater scope for airports to price, invest and operate efficiently. Price monitoring enhances market transparency by allowing the community to scrutinise prices and market outcomes, and can also assist the competitive process, without resort to heavy-handed price controls.'*

In other words, in the Government's view, airports did not have a clear incentive to exercise any market power they may have had. However, it did reserve the right to bring forward the review, or conduct a separate review, if it appeared that there had been unjustifiable price increases.

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26 The ACCC produces two reports – one outlining price movements and financial reporting at monitored airports and the other measured changes in service quality.

The 2003/04 reports can be viewed at: http://www.accc.gov.au/content/index.phtml/itemId/597377/fromItemId/347781.

27 See: http://www.accc.gov.au/content/index.phtml/itemId/597377/fromItemId/347781.

28 See the Government's announcement at: See: http://www.treasurer.gov.au/tsr/content/pressreleases/2002/024.asp.

29 See: http://www.treasurer.gov.au/tsr/content/pressreleases/2002/024.asp.

B.2. Victorian Shipping Ports

Since July 2005, Victorian ports ceased being subject to formal price regulation, with a price monitoring arrangement similar to that in place at Australian airports applying. The principal difference (between Australian airports and Victorian ports) is that the Port of Melbourne Corporation ('PoMC'), by virtue of its continued substantial market power, is required to fulfil additional requirements. In other words, a 'dual form' of regulation is used. First, the prices at all ports are monitored by the ESC, with a review scheduled for June 2010. Second, PoMC is required to adhere to a Pricing Policy Statement ('PPS'), clearly specifying the manner in which it formulates its prices.

PoMC is also be required to derive 'standing offer' or 'reference' tariffs that are available to all users.[30] The PPS must outline how PoMC formulates these tariffs, including how its approach complies with certain overarching principles for efficient price setting.

PoMC is required to provide the ESC with a significant amount of information to enable it to undertake this monitoring role, including tailored financial statements for prescribed services, including – among other things – revenues, operating costs and profits, assets and liabilities, capital expenditure. PoMC must also provide the ESC with its port charges and levels of demand for each of the prescribed port services and indicators of service quality and productivity. Using that information the ESC annually publishes a Monitoring Report outlining movements in prices, costs, profitability, capital expenditure and other measures.

As with airports, provided ports comply with the overarching pricing principles they can set whatever prices they deem appropriate. However, any deviation from these principles risks the re-imposition of price controls. Much like the ACCC in its regulation of airports, the ESC reserves the right to prescribe prices if it believes there is sufficient evidence of a misuse of market power. Accordingly, the practical effect of these arrangements is that, whilst not regulated, Victorian shipping ports, like airports, are subject to an ongoing threat of regulation.

[30] This is similar to the approach proposed by the ICRC for electricity retail pricing in the ACT.

Appendix C. Regulatory Precedent

The following appendix summarise some relevant regulatory precedent.

C.1. ACT

C.1.1. Proposed FoPC

Retail contestability has been in place in the ACT since 1998 for large customers and 2003 for small customers. Over the past three years while the contestable market for small customers in its infancy, the ACT regulator, the ICRC applied regulated transitional tariffs to ease the transition to full contestability. However, in its April 2006 Final Report, *Retail Prices for Non-contestable Electricity Customers*, the ICRC concluded that:

> 'the ACT retail electricity market exhibits the characteristics of a competitive market and that the continuation of a regulated retail tariff is no longer required.' (page 2)

It is worth noting that the ICRC observed that competitively supplied services were up to 10% lower priced than regulated tariffs. The characteristics upon which the ICRC determined that the ACT electricity retail market was consistent with a competitive market were:

- the existence of a number of competing retailers and/or the imminent potential entry of new competitors.
- actual and/or potential competition between these retailers.
- innovation in the products and services offered to consumers by active retailers.

In making this decision, the ICRC noted that:

- the transitional franchise tariff (TFT) was not intended to operate as a 'safety net' for vulnerable customers; and
- it supported the continued targeted use of CSO payments, rebates and concessions, and involvement of community support and welfare agencies to assist those experiencing financial hardship.

In addition to these measures the ICRC proposed revision to the Utilities Act 2000 to establish a 'deemed contract' which effectively took the place of the current TFT. While this 'deemed contract' will not have a determined price 'direction' (ie, ActewAGL can vary its prices as it sees fit) it will continue to afford customers the same consumer protections contained in the TFT arrangements including:

- obligation to supply on a non-negotiated deemed contract;
- ability for customers to move on or off the deemed contract at their discretion; and

- no minimum periods for the deemed contract and no exit fees.

To allow for the relevant legal changes to be implemented in the Utilities Act 2000, the current TFT regulation has been extended by a year (ie, out to 30 June 2007). This period will be regulated via a CPI increase on the 2005/06 TFT. Any application by ActewAGL for an increase above CPI would have been subject to ICRC cost based review unless proposed tariff increases exceeded CPI (which they did not).

While the ICRC has recommended the removal of regulation, it has also recommended a three year transition period over which time it will continue to monitor the ACT retail electricity market to ensure competitive market conditions are maintained. Where it deems this is not the case, it may seek to initiate a reference to review movements in the deemed tariff. At the end of this period the ICRC and ACT Government could then conclude whether effective competition has been demonstrated. During this period ActewAGL is expected to notify the ICRC of any proposed movements in the deemed contract.

C.1.2. Current FoPC

The exact form of price regulation applied in the ACT is not publicly available. Through discussions with industry contacts we have been able to ascertain that, currently and until 30 June 2007 (subject to legislative change by that date), the ICRC regulates[31] ActewAGL's TFTs via:

- CPI+X weighted tariff basket with quantity data lagged by 18 months;
- ActewAGL is able to raise prices faster than CPI+X if it can "demonstrate"[32] that the price increase is due to:
  - wholesale market conditions affecting ActewAGL's proposed benchmark price;
  - the form of market arrangements adopted in the ACT market;
  - NEMMCO fees and charges;
  - MRETS/greenhouse levies;
  - FRC customer churn rates (which give rise to FRC cost recovery different to forecast levels);
  - network tariff variations; and
  - other fees, taxes and imposts.
- We understand that there are *no* side constraints applied to the tariff basket.

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31 Once the Government has approved their form of price regulation.

32 Although rules for how these issues can be demonstrated are not well developed (at least in a public setting).

In its 2003 price directions final determination the ICRC estimated retail costs based on the following:

- retail costs, including:
  - customer care and call centre costs
  - billing costs
  - sales and marketing costs
  - collection and default costs
  - administration costs (business overheads, such as finance, human resource management, and regulatory administration)
  - retail costs associated with transfers and operating in a contestable market
  - a retailer margin, or a return to the shareholder commensurate with the level of risk and investment required for the business
- energy costs (the costs of purchasing energy in the market on behalf of customers), including:
  - costs of energy purchases in the NEM
  - costs of purchasing energy under contracts with generators
  - costs of hedging exposure to price and quantity fluctuations
  - NEMMCO fees and ancillary service charges
  - allowances for renewable energy costs
  - the effect of network losses in the ACT (both transmission and distribution).

The April decision extends this form of regulation by one year as discussed above.

C.2. UK

The UK domestic retail energy market was opened to full contestability in the late 1990s. Since that time, the UK retail market has evolved to become one of the most active energy retail markets in the work, in terms of active customer participation via retailer switching. Consequently, the last regulations on retail prices in the UK gas and electricity markets were removed in April 2002. Thus no formal price control is applied. However, OFGEM (the UK regulator) still enforces certain customer protections via supply licence conditions. These conditions are the subject of a current review aimed at reducing these conditions and relying to a greater extent on:

- the effective competition in the gas and electricity retail markets; and

- existing consumer protection laws that apply to all industries in the UK.

In July OFGEM released its initial policy proposals for the review which propose the retention of specific licence conditions to protect vulnerable consumers including:

- the provision of multiple payment methods and options (including cash instalments);
- a moratorium on disconnecting pensioners during winter; and
- requirement to offer customers experiencing payment difficulties the option of installing a prepayment meter.

Existing conditions to be removed include obligations and restrictions on:

- contracts being terminable within 28 days;
- termination fees; and
- publication of supply terms.

The removal of these requirements has been justified by the sustained presence of effective competition, enhanced potential for self-regulation, desire to simplify licence terms to foster new retailer entry and establishment of the Energy Services Ombudsman.[33]

OFGEM conduct periodic reviews of the state of retail competition to ensure this remains sufficient to justify their light-handed approach. These reviews include monitoring that there are no significant impediments to market entry or exit, and the margins are sufficient to sustain potential market entry.

C.3. South Australia

Full retail contestability (FRC) commenced in the South Australian electricity market in 2003, with all electricity customers now able to enter into a market contract with their retailer of choice.

Standing contract prices have been established in legislation to protect small customers (i.e. those customers whose annual electricity consumption is less than 160 MWh) who do not enter into a market contract.

AGL SA, as the prescribed retailer under the Electricity Act 1996, is required to offer to sell electricity to small customers at a standing contract price and subject to standing contract terms and conditions. The Essential Services Commission of South Australia (ESCOSA) regulates the standing contract prices which AGL SA can charge under its standing contracts.

In 2004, the Commission released its final decision on the price path regulation for standing contract prices. The decision used an average price cap for ‘retailer tariffs’ (ie,

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33 See OFGEM Supply Licence Review – Initial Policy Proposals, July 2006.

the retailer controllable cost components) to the total basket of standing contract tariffs, in conjunction with side-constraints on individual tariff changes.

C.3.1. FoPC

The average retail price cap (ARPC), expressed in $/MWh, is applied to all regulated tariffs in aggregate. The price cap allows for an increase on the previous year's ARPC as given by the following formula:

$$ARPC_t = ARPC_{t-1}(CPI_t(1-x))$$

Where:

$$x = 1.05\%$$

$$ARPC_t = \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} q^{ij}}{Total\ Consumption}$$ (ie, total revenue divided by total consumption)

The price cap involves AGL submitting to the Commission information on the number of standing contracts and *forecast* consumption on these and demonstrating compliance with the above formulae.[34]

The ESCOSA also applies a side constraint on the allowed annual increase in individual tariffs. This is set at an increase of CPI+4% or $40 (whichever is greater).

C.4. Victoria

The Victorian Government has negotiated retail price paths with the Victorian gas and electricity retailers for those customers who have not taken up market contracts. While limited information is available on the specific details of the Victorian price paths and the basis of their determination, its is understood that these price paths are of a CPI-X form and cover the period 2004 to 2007. These price paths are enforced by the Department of Infrastructure, and *not* the State's economic regulator, the Essential Services Commission.

C.5. Queensland

In Queensland there are currently two incumbent retailers (ENERGEX and Ergon Energy) who supply all small customers (or non-contestable or franchise customers) in their geographic service areas based on prices set by the Queensland Government. Differences between the revenue earned from the Government determined tariffs for franchise customers and the cost of supplying these customers are funded through Community Service Obligation payments from the Government to the retailers.

Large users are currently free to enter into contestable contracts with any retailer and, from 1 July 2007, full retail competition will also be implemented for small customers.

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34 Samples of AGL SA's tariff approval submissions are available at http://www.escosa.sa.gov.au/site/page.cfm?u=162&c=696

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13 Appendix B – LECG report on energy purchase cost allowance for regulated electricity retail tariffs and charges

Energy Purchase Cost Allowance for Regulated Electricity Retail Tariffs and Charges

2007-2010

Report for

Integral Energy

Simon Orme
Toby Stevenson
Kieran Murray
Simon Hope
Stuart Allinson
Adrian Palmer

September 2006

LECG

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Table of contents

1 Summary

The Independent Pricing and Regulatory Tribunal (IPART) is in the early stages of reviewing Regulated Retail Tariffs and Charges for Electricity for the period 1 July 2007 to 30 June 2010. In response to its Terms of Reference for this review, IPART released an Issues Paper in July 2006 (DP 85) seeking responses from stakeholders and retailers.

We have been commissioned by Integral Energy (Integral) to assist in developing an understanding of some of the matters raised in the IPART paper. In particular, our Terms of Reference task us with providing a response to Integral on issues relating to the estimation of appropriate allowances for: the long run marginal cost of generation; wholesale market and green energy purchase costs; and hedging, energy risk management and transactions costs. These costs are a major component in the total default retail tariffs that are under review.

IPART's Terms of Reference require it to ensure that regulated tariffs are at cost reflective levels for all small retail customers by 30 June 2010. In setting tariffs at cost reflective levels, IPART must consider the following.

- An allowance for electricity purchase costs based on assessed long-run marginal cost (LRMC) of electricity of a portfolio of *new entrant* generation.
- Retailers' 'hedging, risk management and transaction costs'.
- The Net System Load Profiles (NSLPs) of each standard retailer, as well as projected future changes in those NSLPs.
- Carbon emissions related costs.

In its previous decision, IPART: [1]

- Set an allowance for energy purchase costs derived primarily from an estimate of the Long Run Marginal Cost (LRMC) of electricity supply.
- Determined there was no requirement to incorporate allowances for hedging, risk management and transactions costs.
- Decided not to calculate an energy purchase cost allowance for each NSLP.

[1] IPART final report and determination for NSW Electricity Regulated Retail Tariffs 2004/05-2006/07 dated 2004, page 39.

This report demonstrates that the method IPART adopted in its previous determination does not result in 'cost reflective tariffs', as is now required under IPART's 2007/2010 Terms of Reference.

Each of the components of cost that form an allowance for energy purchase costs (henceforth the Energy Purchase Cost Allowance or EPCA[2]) properly recovered in retail tariffs are quantifiable and capable of being forecast for the review period. As a result, we are firmly of the view that IPART will be able to ensure regulated tariffs are at cost reflective levels for all small retail customers by 30th June 2010.

The appropriate method for estimating the EPCA is the method that would be used by an efficient, prudent, new entrant retailer in establishing what is referred to as the internal or wholesale transfer price (WTP) for contract customers settled against a unique load profile. The WTP represents the 'risk free' cost of energy supply to meet a particular customer or representative[3] customer load profile. It *includes* the expected cost of spot market purchases, the net outcome of purchasing hedges against spot prices, and wholesale market costs, such as NEM fees, MRETs and NGAS.

The WTP necessarily represents a margin over external hedging and wholesale market costs. This represents an allowance for energy risk management and transactions costs.

Further, we suggest there is an additional component to take into account in setting the WTP to address additional risks associated with the obligations imposed on standard retailers and the constraints on energy trading that may be imposed on NSW owned energy corporations. Thus the standard WTP method needs to be extended in the case of a WTP for default contracts.

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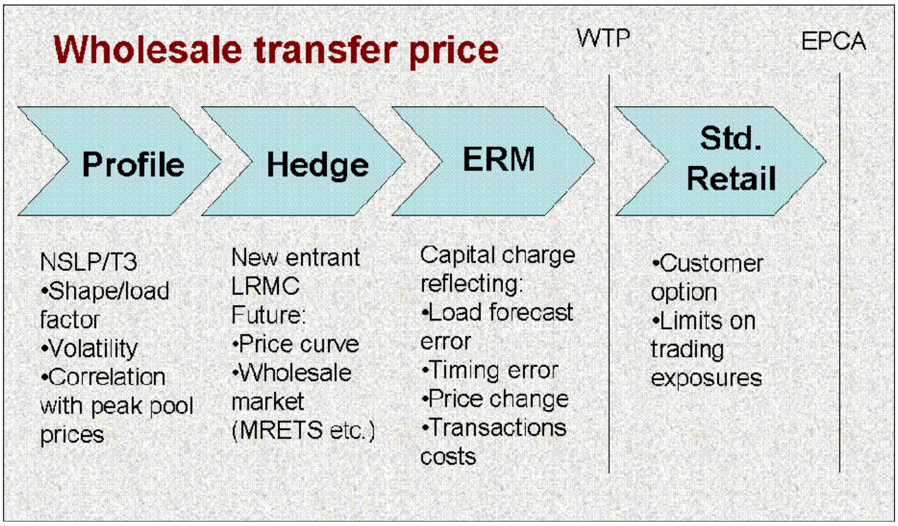
[2] As described in detail below, we use the term EPCA as shorthand to summarise: LRMC, NEMMCO, MRETS and NGACs costs, and hedging, energy risk management and transactions costs. It is the major component of retail tariffs together with network use of system charges.

[3] Representative customer is an aggregation over the total NSLP. While for large customers with time of use meters a retailer will typically assign a WTP for each customer, in the case of mass market customers, a WTP will be assigned for all customers settled against the relevant NEMMCO load profile. Thus there is just one WTP for the Integral NSLP. Retailers are likely to segment the representative customer for this NSLP in targeting potential new customers but in principle the WTP would remain. Naturally, the WTP is adjusted over time to reflect new information regarding wholesale and retail market conditions.

The graphic below illustrates the transfer price methodology.



There are three main determinants of the WTP for a given representative customer:

- The specific load shape of that customer, ideally for all trading intervals, and the degree of uncertainty over forecasts of that load shape in the future;
- The estimated cost of purchasing a portfolio of hedges corresponding to each trading period for the forecast NSLP in question (a proxy for which could be derived using an adjusted estimate of new entrant Long Run Marginal Cost (LRMC) for example); and
- Energy risk management and transactions costs.

A prudent retailer would set a different price for each of the four NSW Net System Load Profiles (NSLP) established and published by NEMMCO for the purpose of NEM settlements. A retailer would not have a single WTP for all contract customers. Rather it would calculate a WTP relative to each customer load profile. This is because the level of the WTP is determined by the unique characteristics of that customer. Key variables include: the customer's peak relative to average demand throughout the year; the predictability and controllability of the customer's demand; and the extent to which the customer's peak demand coincides with system wide peak demand, and hence high pool prices.

Our review of data provided by Integral suggests the WTP for the Integral NSLP will be significantly higher than for the other NSW NSLPs. This reflects the fact the Integral NSLP has the highest correlation with system wide peak demand and high price periods. Further, during these periods, there is a higher level of volatility both around demand and spot prices. Thus load forecast and price risks associated with meeting that load are greater.

The methodology adopted by IPART in the previous determination for estimating LRMC calculates theoretical prices necessary to cover the total cost of an optimal generation portfolio, assuming perfect foresight and completely variable generation capacity. The methodology produced prices at various points on the load duration curve and averaged these prices to arrive at the $47 per MW figure adopted by IPART.

However, new generators will enter the market only when prices in the market are sufficient to cover their LRMC, taking into account the imperfections of real markets. These imperfections include lumpy investment (rather than perfectly variable capacity), uncertainty as to future demand, and demand volatility. Hence, the LRMC of new entrant generators (or the prices in the market sufficient to cover the LRMC of a new entrant) are higher than those produced by the IES methodology (with its unrealistic assumptions about perfect foresight and perfectly scalable generation). Cost reflective tariffs must be set using approaches that reflect costs in the real world, not some unrealistic theoretical world.

As generators can reasonably expect that prudent, efficient retailers will enter into sculpted hedge contracts, the LRMC estimates determined by modelling the market would reflect the sculpted hedge prices a retailer could expect to pay for hedges sculptured against the average NSLP for all retailers. The LRMC of new entrant generators, however, does not reflect the total costs a new entrant retailer would occur in purchasing energy to match its actual NSLP. There are additional costs that must be met. These costs include the following.

- The cost of matching the actual NSLP of the retailer. The retailer's load may be more volatile or have a lower load factor, meaning the prices it pays will be higher than the State average.
- The cost of energy lost in transmission and distribution.
- The cost of hedging, risk management, and transaction costs.
- The additional margin as a default retailer.
- Other costs, such as NEM fees, MRETs, NGAS related costs.

These are some of the costs that must be reflected in the regulated tariff if it is to be "cost reflective" by 2010.

In calculating an appropriate EPCA for supplying customers under default retail contracts, an additional margin needs to be included over the transfer price that would be applied to the same customer on a fixed duration competitive contract settled against the NSLP. This reflects the costs to retailers of providing for the higher-level of optionality granted to the customer under the default retail contract.

There is a further point that may need to be taken into account in assessing the EPCA that would apply to default customers: shareholder constraints on

Integral's energy trading exposures. The NSW government, as shareholder, has imposed constraints on energy trading exposures.[4] These constraints could result in the WTP being higher than it would be for a new entrant retailer and a corresponding requirement for a higher EPCA. This is because the limit may oblige the retailer to purchase hedges at a substantial premium relative to the equivalent ERM cost, properly calculated using a capital at risk, or similar methodology.

Under the proposed method, the immediate influence of an assessment of pool prices is the ERM component of the WTP methodology. Pool prices may also be a factor in reconciling the LRMC analysis with hedge price observations. Otherwise, we suggest pool prices are not a significant factor in the analysis for the derivation of the EPCA.

The potential for changes in the NSLP during the course of the 2007-10 price control period is one of the factors in support of setting the EPCA above the WTP for a corresponding contract customer. In the case of contract customers, the then current shape of the NSLP is one of the factors to be taken into account in setting the WTP for new or renewing customers. Stylistically, roughly half the volume sold against the Integral NSLP will be able to be re-priced during the price control period. This option to re-price is not available with respect to the Integral retail tariff business and thus there is a greater exposure to any changes to the NSLP.

The proposal to extend the standard WTP methodology, in order to reflect the higher risk profile in supplying against the standard default contract, will result in an EPCA that will be higher than the WTP for a corresponding customer on contract. We acknowledge this raises the question of "headroom" in retail tariffs. However, we note that, as a result of FRC, to the extent there is headroom, it stimulates retail market competition and thereby reduces the size of the headroom.

It is possible to identify a number of factors that suggest a step increase in the EPCA will be required in the case of the default tariff business supplying the Integral NSLP, compared to that identified in the previous determination. This reflects the substantial shortfall in the 2004-2007 determination given the changes in the current Terms of Reference to incorporate energy risk management and transactions costs; the Integral NSLP; and the fact the previous LRMC calculation made some unrealistic assumptions. Importantly, the previous LRMC analysis did not adequately reflect the imperfections in the market, and dismissed the need for energy risk management and transactions costs to be added to the underlying LRMC estimate.

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[4] See NSW Office of Financial Management: Policy and Guidelines Paper TPP 99-5, dated October 1999

As well as a suggested step increases in the EPCA, there is also the potential for ongoing increased supply costs to be factored into the EPCA. These need to be considered so that the EPCA is cost reflective over the entire determination period. This reflects factors such as a possible tightening in the supply –demand balance as suggested by the current NEMMCO Statement of Opportunities for NSW (which suggests NSW will rely on increased inter-state imports from 2008/09), and likely pressure on fuel prices and capital costs as inputs to LRMC.

The method for estimating the EPCA in this report is based on replicating the full energy purchase costs that would be faced by a stand-alone new entrant retailer. Reflecting IPART's Terms of Reference, the proposed method includes an allowance for transactions costs and energy risk management risks created by competitive purchasing from generators. The implication is there would be no adjustments to the EPCA to reflect the gradual removal of ETEF. There does not seem to be any advantage from an economic efficiency perspective in deferring the introduction of justifiable price rises because of the timetable for the phase out of ETEF.

2 Introduction

The Independent Pricing and Regulatory Tribunal (IPART) is in the early stages of a process for reviewing Regulated Retail Tariffs and Charges for Electricity for the period 1 July 2007 to 30 June 2010. In response to its Terms of Reference for this review, IPART released an Issues Paper in July 2006 (DP 85) seeking responses from stakeholders and retailers.

We have been commissioned by Integral Energy (Integral) to assist in developing an understanding of some of the matters raised in the IPART paper. In particular, our Terms of Reference task us with providing a response to Integral on issues relating to the estimation of appropriate allowances for: the long run marginal cost of generation; wholesale market pass through costs; and hedging, energy risk management and transactions costs. These costs are a key component in the total retail tariffs that are under review.

2.1 IPART Terms of Reference

Among key changes in IPART's 2007/10 Terms of Reference, relative to its Terms of Reference for the 2004/07 period, are the following:

- A requirement that IPART *ensure* that regulated tariffs are at cost reflective levels for all small retail customers by 30 June 2010 (previously the requirement on IPART was to move tariffs towards full cost reflectivity as far as practical).
- An allowance for electricity purchase costs based on assessed long-run marginal cost (LRMC) of electricity of a portfolio of *new entrant* generation to supply the load profile of customers remaining on regulated tariffs (previously the requirement to consider LRMC did not specify whether LRMC of existing or new entrant generators should be used).
- A need to recognise retailers' 'hedging, risk management and transaction costs', given the Government's decision to phase out the NSW Electricity Tariff Equalisation (ETEF) scheme fully by the end of the period (previously, there was no explicit requirement on IPART to consider hedging, risk management and transaction costs).
- Recognition of the importance of the Net System Load Profiles (NSLPs) of each standard retailer, as well as projected future changes

in those NSLPs (previously, IPART was required only to consider the demand profile of all customers remaining on regulated tariffs).[5]

- Incorporation of carbon emissions costs, including the proposed requirement in the NSW Greenhouse Plan to require energy retailers to offer a 10 per cent Green Power component to all new (or moving) residential customers, as well as a mechanism to address any new, compulsory carbon emissions scheme.

In its previous decision, IPART set an allowance for energy purchase costs based on an estimate of the Long Run Marginal Cost (LRMC) of electricity supply. This reflected IPART's view the NSW ETEF scheme provided standard retailers with suitable protection against risks associated with purchasing electricity, to meet its regulated retail load, from the wholesale market. IPART determined there was no requirement to incorporate allowances for hedging, risk management and transactions costs within the estimation of the overall allowance for energy purchases.[6]

In addition, in its previous decision, IPART decided not to calculate an energy purchase cost allowance for each NSLP. This was on the basis that practical problems effectively prevented the Tribunal from determining individual retailer values, due to problems with the load profile data used in the LRMC analysis.[7]

2.2 Integral terms of reference

Our terms of reference for the present study are as follows:

1) A theoretical review of the LRMC of electricity generation. The review should include benchmarking analysis of the LRMC estimates used in other regulatory jurisdictions for the purposes of setting safety net retail prices;

2) Validation of Integral Energy's calculation of the appropriate level of hedging, risk management and transaction costs for inclusion in regulated retail tariffs.

3) Test Integral Energy's assumptions of the cost of electricity for Integral Energy's regulated retail customer base. The model must consider and demonstrate the effect of:

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[5] IPART is concerned with regulating prices for default customers in the Tier three customer tranche. The effective T3 profile is an aggregation of the NSLP and the Controlled Load Profile (CLP) depending on the tariff in question.

[6] IPART final report and determination for NSW Electricity Regulated Retail Tariffs 2004/05-2006/07 dated 2004, page 39.

[7] Ibid page 38.

a. A phasing out of ETEF (over both a period of time and an immediate termination);

b. Projected changes in Integral Energy's net system load profile over the determination period;

c. Any forecasting risks that retailers will face in the absence of the ETEF and whether these risks are different for Integral Energy and a mass market new entrant retailer;

d. Any changes to these costs driven by the requirement of Integral Energy to offer a 10 per cent Green Power component to all new (or moving) residential tariffs; and

e. Any differences in these costs between Integral Energy and a mass market new entrant retailer.

4) Whether the concepts of LRMC and hedging are compatible and how any relationships should be considered by the Tribunal in the determination.

5) Whether the Tribunal should consider hedging costs against the pool price or only allow costs for hedging above the LRMC estimate.

6) Any other matters that are relevant to determining the cost of energy.

2.3 Structure of this report

The structure of the remainder of this report is as follows:

- The environment within which electricity retailers operate is briefly described in chapter three.
- The concept of the energy purchase cost allowance (EPCA) and the method for calculating this is introduced and described in chapter four.
- The proposed method is applied to default retail customers settled against the Integral NSLP. This is discussed in chapter Five.
- Chapter six discusses the concept of LRMC and highlights difficulties with the LRMC methodology for generation used in the decision for the current retail price control period.
- Chapter seven looks at the suggested LRMC approach for building a cost reflective EPCA.
- Finally, chapter eight draws the analysis together to reach conclusions on the issues in the Terms of Reference. This includes discussion of specific matters, including options around resetting the EPCA during the phase out of ETEF.

3 Background information

3.1 Introduction

This section briefly sets out relevant contextual information regarding Integral Energy and aspects of the national electricity market (NEM).

3.2 Integral Energy

Integral is a NSW energy corporation operating under the Energy Corporations Act 1995. It holds both distributor and retail licences under the Electricity Supply Act 1995. In addition, Integral is one of three NSW standard retailers obliged to offer default retail tariffs within its network supply area.

At the end of June 2006, Integral had approximately 530,000 default retail customers on standard retail contracts ('default customers'). All of Integral's regulated customers are within Integral's network supply area. As shown in the map below, this supply area covers Western Sydney, the Blue Mountains, the Southern Highlands, the Illawarra, and Shoalhaven.

Any 'small' retail customer (defined as consuming less than 160MWh per annum) within the Integral supply district is eligible to purchase electricity under Integral's default retail contract. This includes:

- existing customers (residential and commercial) who elect to remain on tariff;
- new retail customers moving into an existing premise;
- customers moving into new premises, for example in new estates; and
- customers on negotiated contracts who elect to return to supply under the regulated tariff.

A Standard Form retail ("regulated") contract sets out the terms and conditions of supply for these customers.[8]

3.3 National electricity market (NEM)

3.3.1 NEM operation

The national electricity market (NEM) was formally established in 1998 and operates across the Eastern Seaboard, South Australia (SA) and Tasmania. The NEM is governed by, and operates under, a comprehensive set of rules known as the National Electricity Rules (NER).

The NEM is operated by a market administrator (NEMMCO). Key NEMMCO functions, for present purposes, include:

- operating the systems necessary to support retail market settlement and competition;
- operating the physical (spot) wholesale market and the generator dispatch system;
- providing settlements services between market participants; and
- purchasing various ancillary services.

In its retail market capacity, NEMMCO maintains a registry of all unique NEM supply points (known as national market identifiers or NMI). It aggregates all consumption data from NMI, estimates transportation losses[9] between generation injection and delivery to NMIs, and creates settlement profiles for each distribution supply district. This system enables NEMMCO to reconcile costs and payments between all market participants in relation to each NMI.

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[8] See Integral's Standard Supply Contract December 2002 at http://www.integral.com.au/index.cfm?objectid=35411B92-8028-BBAF-184A28B81237069B#d

[9] Transport losses are an important consideration for energy retailers. According to NEMMCO, average losses are equivalent to approximately 10% of the total electricity transported between power stations and market customers. This means that, overall, retailers must purchase and recover the cost of an additional 10% in energy from the wholesale market to compensate for transport losses. See http://www.nemmco.com.au/nemgeneral/000-0187.pdf

3.3.2 Observations on NEM market structure over time

Since the NEM was established, privatisation has occurred in SA and the ACT and a partial privatisation is due in Queensland. Traditionally, many electricity and gas retailers operated as integrated distribution and supply businesses in which there was no clear distinction between what constituted physical supply (via the network) and energy supply (retail). The development of standalone retail businesses separates monopoly (poles and wires) from potentially competitive functions (customer services). As a result of a series of commercial and policy decisions, most privately owned retail businesses have been separated from monopoly lines businesses.

An additional observed in the NEM has been consolidation and in some instances "re-integration". This reflects economies of scope and scale in the electricity sector. In NSW, the six NSW energy corporation retailers on NEM establishment have now been reduced to three. In the case of private retailers, subject to competition law, there is evidence of both horizontal and vertical integration. Horizontal integration includes dual fuel suppliers, while vertical integration refers to integrated generator/retailers.

While the retail sector in NSW has consolidated, the NSW generation structure has changed little since 1998. The three NSW owned generators, together with Snowy Hydro Corporation, still provide the bulk of generation capacity in the NSW region.

The advent of the Queensland-NSW interconnector (QNI) in 2000, together with enhancements to interconnectors between the NSW, Snowy and Victorian regions, has introduced a level of additional generation competition from Queensland and Victorian generators. The construction of major generation at the northern end of QNI is also a significant development.

3.3.3 A pool market

Wholesale electricity markets typically operate under what is referred to as an electricity pool. The NEM operates under what is referred to as a gross pool market design. This means virtually all electricity (there are some exceptions around micro and embedded generation) must be traded through the pool. NEMMCO establishes and publishes pool prices that reflect the outcome of bidding between electricity producers and retailers for quantities of electricity within each trading interval, at each trading region or location within the pool. Because demand and supply is constantly changing in the NEM there are 48 trading intervals daily (i.e. twice an hour in a 24 hour period). Moreover, there are now six NEM regions and thus six location prices for each trading interval. Pool prices can vary greatly depending on the time of day, day of the week, weather, and many other factors. In the NEM there is at present a maximum cap on the wholesale price of $10,000 per megawatt hour (MWh).

Ancillary services are those services used by NEMMCO to manage the power system safely, securely and reliably. Ancillary services maintain key technical characteristics of the system, including standards for frequency, voltage, network loading and system re-start processes.

Retailers are obliged to pay NEMMCO in relation to all of the services outlined above. These include NEMMCO fees, and ancillary services charges. In addition, in order to meet NEMMCO prudential requirements, retailers may also be required to obtain bank guarantees and pay guarantee charges.

3.3.4 A retailer in the NEM

An energy retailer in the NEM buys wholesale energy and energy transport services, and sells delivered energy to individual customers. It may also supply related services based on its customer relationships and business systems; for example gas as well as electricity. Full retail contestability (FRC) was introduced in NSW in January 2002. This gives all customers on default contracts the option of seeking supply under a competitive electricity contract.

The network services purchased by retailers are regulated under the NER. Network charges consist of Transmission and Distribution Use of System charges. Retailers combine these charges into Network Use of System (NUoS) charges, which are passed through to end use customers at regulated prices (subject to any retail tariff regulation including side constraints).

These NUoS charges are one of a number of costs that are 'passed through' from retailers to customers, and are associated with operating in the NEM and meeting NSW electricity retail licence conditions. Wholesale costs include:[10]

- NEMMCO charges;
- the cost of purchasing renewable energy to meet Mandatory Renewable Energy Target (MRETs) obligations; and
- the cost of purchasing NSW Greenhouse Gas Abatement Certificates (NGACs) in order to meet greenhouse gas emissions abatement obligations.

Under the MRETs scheme, retailers are obliged to purchase a minimum portion of renewable energy as a proportion of their total sales' volumes. In practical terms, this means retailers are obliged to create or purchase Renewable Energy Certificates (RECs) and comply with various disclosure obligations.

Under the NSW Greenhouse gas emissions abatement scheme (NGAS), retailers are obliged to meet per capita emissions benchmarks targets. This involves creating or purchasing Greenhouse Gas Abatement Certificates relative to each retailer's proportion of NSW greenhouse gas emissions created from electricity consumption.

Both MRETs and NGAS impose penalties on retailers who fail to meet their obligations under these schemes. Both schemes apply equally to all NSW retail licence holders.

3.3.5 Measuring consumption, and settlement

The NER, together with various State metrology procedures, regulate the measurement of electricity consumption in the NEM. Because settlements are calculated on a half hourly basis, NEMMCO's retail systems require time of use consumption data.

In the case of small retail customers on default retail tariffs, the vast majority operate under cumulative consumption meters and half hourly consumption for settlements purposes must therefore be estimated. NEMMCO creates and regularly updates half hourly profiles for each distribution supply area, based

[10] For retail contracts, 'pass-through' of these costs is a matter for the terms and conditions of the contracts. In the case of default retail tariffs, 'pass through' refers to the allowances for these costs made in the retail tariff determination. Note that both MRETs and NGAS schemes incorporate penalties for non-compliance. We suggest these would not be considered pass through costs and that any allowance for the risk of penalties would form part of a retailer's overall regulatory compliance risk.

on a representative sample of customers with cumulative consumption meters.

In NSW this estimate uses sample data to create a net system load profile once controlled load (known as the controlled load profile (CLP has been 'peeled off')). The resulting profile is referred to as the net system load profile (NSLP), of which there are four in NSW, corresponding to four network supply areas.[11] Note that standard contracts cover tariffs both for CLP and NSLP (known in aggregate as tranche three or T3). The IPART Issues Paper refers to the NSLP and thus this is used as the unit of analysis for the remainder of this discussion.

3.4 Risk management in the NEM

A retailer is obliged to purchase virtually all its energy from the NEM at prevailing pool prices. However, this does not mean a retailer's energy purchase cost is merely the sum of its pool purchases.

A stand-alone, prudent retailer will seek to minimise its exposure to high pool prices and potentially substantial financial losses by entering into a range of financial arrangements with generators and other counterparties. These instruments are generally referred to as "hedges" or "derivatives".

3.4.1 Hedges

In the context of the electricity market, hedges can take a number of forms, but are essentially ways for market participants to manage risk exposure by locking in prices. Hedges can either be traded directly between parties ('over the counter') or via a futures exchange (e.g. the Sydney Futures Exchange) but are not administered centrally by NEMMCO.

Electricity hedges in the NEM typically take their form from 'master agreements' under the International Swaps and Dealers Association (ISDA) and are adapted to Australian laws by the Australian Financial Markets Association (AFMA). Under current accounting rules, participants holding or trading in financial instruments are obliged to disclose these as financial assets or liabilities in their balance sheets.

A common form of hedging in the NEM is what is known as 'contracts for difference', against spot prices. Under this arrangement the parties agree to a 'strike price'. For trading intervals where the pool price is below the strike price, a retailer will pay the difference between the two prices so that the other party receives the strike price, not the pool price during these intervals.

[11] See 'Understanding Load Profiles Published from MSATS, prepared by: Metering & Settlement NEMMCO, Document No: MT_MA1772V004

However, for intervals when the pool price is above the strike price, while the retailer pays NEMMCO the prevailing pool price, it receives the difference between the NEMMCO price and the strike price – in other words it pays only the strike price. Other forms of hedges include price caps and options to buy quantities at a pre-agreed price in a given trading interval.

As well as risk emerging from variations in the spot price, where a retailer wishes to hedge its load with a generator in another region it will also have to manage inter-regional price risk. This can occur when trade between regions is constrained, for example due to a transmission outage. Some hedges – for example with generators in other regions – may cease to operate in the event of a price separation event. Accordingly, a further set of hedges have been developed to allow for the allocation of inter-regional risk, and the subsequent compensation for taking that risk.

3.4.2 Other forms of risk management

Aside from trading in hedges or derivative products, there are other risk management options potentially available to retailers; most notably ownership of physical generation assets. Another option is to mimic generation ownership by entering into long-term energy purchase contracts closely linked to physical generation capacity (power purchase agreements).

There is a further set of risk management options concerning demand management. For example, a retailer may contract with certain customers to curtail consumption and sometimes even to 'buy back' electricity at an agreed price during peak price periods.

3.4.3 Energy risk management and transactions costs

Despite there being a range of potential risk management options available to retailers, it is seldom the case that a stand-alone retailer would fully hedge its load. Fully hedging is a theoretical possibility, and would transfer all risk to other parties, but few generators offer such contracts and where they do the premium for absorbing all retailer's energy purchasing risks may tend to make the resulting retail price required uncompetitive.

More typically retailers will purchase hedges with the aim of locking in a price for a large proportion of their expected energy purchase volumes. The residual risk exposure that remains is managed actively by in house traders within the guidelines set out in a Board approved risk management or internal transfer price policy. This residual risk exposure will be determined by the retailers' appetite for risk and access to risk capital, and a desire to minimise the expected cost of its total energy purchases.

A prudent, efficient, retailer will seek to price the value of this residual risk exposure, and to recover this via the price of each unit of energy sold. This price reflects a charge on the capital allocated to the residual risk exposure.

3.5 Electricity Tariff Equalisation Fund

With the expiration of vesting contracts at the end of 2000, the Government considered ways to manage what it saw as risks for retailers associated with purchasing wholesale electricity for small retail customers who elect to purchase electricity under standard terms and conditions; including regulated retail tariffs.[12] The preferred option, introduced on 1 January 2001, was the Electricity Tariff Equalisation Fund (ETEF). In introducing the ETEF, the Government sought to offer regulatory price protection to retailers (for their regulated retail load), while also seeking to limit the exposure of the Government to any unacceptable financial risk.[13]

It did so by requiring that when pool (i.e. spot) prices were lower than a regulated energy cost (or REC), regulated retailers (or standard retail suppliers as denoted by the NSW Treasury) were required to pay money into the ETEF. When pool prices exceeded the energy cost component in the regulated tariff, the ETEF would make payments to standard retail suppliers to enable them to purchase wholesale electricity for regulated customers and still earn a regulated margin.[14] If there should be a shortfall in the ETEF, Government owned generators in NSW would be required to make payments into ETEF to fund the shortfall.

By using the pool price as a comparator for the REC, the ETEF system effectively assumed that without ETEF, retailers would be meeting their regulated retail load using pool purchases, or from other mechanisms with prices analogous to those present in the pool.

The REC was based on the long run marginal cost of the generation system, as determined by IPART as part of its regulated retail tariff determinations. Because of the variability in tariffs between different customers, the REC used in the ETEF varies for each standard retailer. In determining the REC for each standard retailer, the NSW Treasury deduces a value that:[15]

- Is derived from the weighted average of the existing tariffs currently in use by the retailer;
- Is sculpted by NEM peak and off-peak times; and

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[12] *"Electricity Tariff Equalisation Fund: Information Paper"*, Office of Financial Management, New South Wales Treasury, December 2000.

[13] ibid, p.1.

[14] ibid, p.2.

[15] ibid. p.6.

- May be annually updated to reflect changes in the distribution of tariffs and the volume of electricity sales related to those tariffs.

In April 2006, the NSW Government finalised new ETEF pricing rules to provide for a phase out of ETEF between September 2008 and June 2010. [16] The programme for phasing out ETEF is set out below.

Stepped phase out of ETEF		
Period	Proportion of tariff load covered	Proportion of tariff loads exposed
Until 27 Sept 2008	100%	0%
28 Sept 2008 – 28 Mar 2009	80%	20%
29 Mar 2009 – 26 Sept 2009	60%	40%
28 Sept 2009 – 28 Mar 2010	40%	60%
29 Mar 2010 – 26 Jun 2010	20%	80%
27 Jun 2010 onwards	0%	100%

The removal of the ETEF mechanism features in the contemporary retail tariff review issues paper released by IPART, who recognise the need to consider potential flow-on impacts that its removal may have. The paper notes the need to consider any effects on hedging, risk management and transaction costs and forecasting risk that may arise in ETEF's absence.

[16] See Electricity Tariff Equalisation Fund: Payment Rules Version 2, dated April 2006

4 Approach

4.1 Introduction

IPART's terms of reference require it to ensure that regulated retail tariffs 'are at cost reflective levels … for all small retail customers by 30 June 2010'. To comply with this obligation, IPART will need to form views as to:

- The costs that are properly reflected in regulated retail tariffs.
- How each of those cost components should be measured.

This section outlines our view as to how the term "costs" should be interpreted in the context of the IPART Terms of Reference. It also describes the cost components recovered through retail tariffs in competitive markets. Subsequent sections discuss in detail how each of those components should be measured.

4.2 Meaning of the term "costs"

IPART is required to ensure that regulated retail tariffs are "cost reflective". Cost can be measured in a number of ways, for example replacement cost or historic cost. The term "cost reflectivity" is not defined in the terms of reference set for IPART. However, the background section of the Terms of Reference provides the following guidance:

> "International and national experience shows that the level of regulated retail tariffs relative to market based prices is the key determinant of how many eligible customers remain on regulated arrangements. For example, if regulated retail tariffs do not adequately reflect all of the costs of supply to small retail customers, both those customers and prospective competing retailers have little incentive to enter the competitive market. Regulated tariffs set below the cost of supply will also inhibit investment in the new generation required as the demand/supply balance tightens, as investors will not be able to recover their costs. Therefore, in order to promote retail competition and investment, regulated retail tariffs which are below the cost of supply should be moved to full cost reflectivity."

The clear intent of the Government is that regulated retail prices should be economically efficient so that regulated tariffs do not discourage competing retailers from entering the market or inhibit new investment. Hence, the appropriate measure of cost for the purposes of calculating retail margins is the full economic cost or opportunity cost of the resources used in providing the retail service. With limited resources, a decision to have more of something is simultaneously a decision to have less of something else. The opportunity cost, or economic cost, of any decision therefore is the foregone value of the next best alternative that is not chosen.

In a well functioning market, the observed market price of a good or a service will likely be closely tied to its opportunity cost. For instance, electricity provided from plant constructed at historically low costs would be priced in the market at its opportunity cost, which is the current cost of meeting the next increment of demand. If the owner of the existing plant cannot achieve this price, it would be better off selling its assets to the new entrant and the new entrant would be better off buying the assets than constructing new plant. Prices in the market therefore trend toward the long run marginal cost of meeting the next increment of demand.

In the sections that follow, we describe a methodology for estimating the full economic costs of retail tariffs for small customers.

4.3 Relevant cost components

In determining regulated tariffs that reflect the full economic cost of supply, IPART must determine the cost components that are properly recovered in retail tariffs. Our brief is to comment on the components of cost that form the allowance for energy purchase costs (henceforth the Energy Purchase Cost Allowance or EPCA[17]).

The appropriate method for estimating the EPCA is the method that would be used by an efficient, prudent, new entrant retailer in establishing what is referred to as the internal or wholesale transfer price (WTP) for contract customers settled against a customer's unique load profile. The WTP represents the 'risk free' cost of energy supply to meet a particular customer or representative[18] customer load profile. It *includes* the expected cost of spot market purchases, the net outcome of purchasing hedges against spot prices, and wholesale market costs, such as NEM fees, MRETS and NGAS, together with risk premiums associated with energy risk management and transactions costs.

A rigorous and quantifiable method for estimating the WTP for contract customers[19] settled against the four NSW NSLPs has now been in place for

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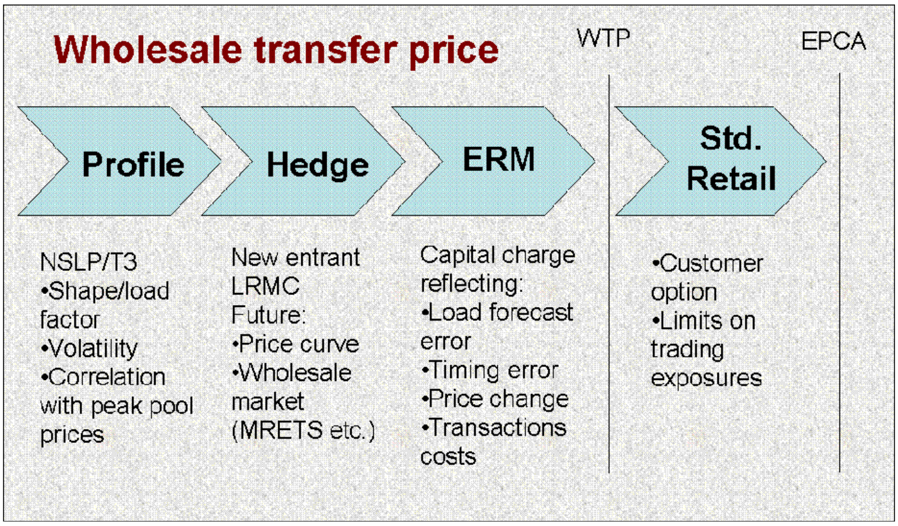
[17] As described in detail below, we use the term EPCA as shorthand to summarise: LRMC, NEMMCO, MRETS and NGACs costs, and hedging, energy risk management and transactions costs. It is the major component of retail tariffs together with network use of system charges.

[18] Representative customer is an aggregation over the total NSLP. While for large customers with time of use meters a retailer will typically assign a WTP for each customer, in the case of mass market customers, a WTP will be assigned for all customers settled against the relevant NEMMCO load profile. Thus there is just one WTP for the Integral NSLP. Retailers are likely to segment the representative customer for this NSLP in targeting potential new customers but in principle the WTP would remain. Naturally, the WTP is adjusted over time to reflect new information regarding wholesale and retail market conditions.

[19] That is, mass market customers without time of use meters which have opted for competitive retail market contracts, rather than the default retail contract.

many years. In addition, the NSW government has established a framework which mandates this type of method is applied by all NSW energy corporations to their energy risk management activities. [20] The WTP necessarily represents a margin over external hedging and pass through costs. This represents an allowance for energy risk management and transactions costs. Further, we suggest there is an additional margin component to address additional risks associated with the obligations imposed on standard retailers and constraints on energy trading that may be imposed on NSW owned energy corporations.

The graphic below illustrates the transfer price methodology.



There are three main determinants of the WTP for a given representative customer:

- The specific load shape of that customer, ideally for all trading intervals, and the level of uncertainty around that shape looking ahead;
- The estimated cost of purchasing a portfolio of hedges corresponding to each trading period for the forecast NSLP in question (a proxy for which could be derived using an estimate of new entrant Long Run Marginal Cost (LRMC) for example); and
- Energy risk management and transactions costs.

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[20] See NSW Office of Financial Management: Policy and Guidelines Paper TPP 99-5, dated October 1999

Sections 4.4 to 4.6 below provide a brief explanation of each of these key components. As noted, an additional, or fourth determinant, is required for default retailers to cover the open offer and restraints on trading. This element is described in section 4.7.

4.4 Customer profile

An efficient, prudent retailer would not have a single WTP for all contract customers. Rather, there is a WTP relative to each customer load profile. This is because the level of the WTP is determined by the unique characteristics of that customer. Key variables include:

- the customer's average relative to peak demand throughout the year[21];
- the predictability and controllability of the customer's demand; and
- the extent to which the customer's peak demand coincides with system wide peak demand, and hence high pool prices.

Accordingly, depending on these and other factors, there will be different WTPs for each NSLP calculated by NEMMCO in relation to the four NSW supply areas[22]. A prudent retailer would certainly not set the WTP based on the average of the four NSLPs. Similarly, IPART's current Terms of Reference require it to recognise the NSLP for each standard retailer, as well as projected future changes in those net system load profiles.

A further factor that needs to be taken into consideration is losses. Due to transmission and distribution losses, retailers need to purchase an additional component over the amount measured and paid for at meters.

4.5 Hedge

Once the characteristics of the profile in question have been identified, the wholesale trading function would seek prices for hedge products to produce a supply portfolio with a profile that is as close to matching the load profile as possible. For example, trading may seek fixed price, fixed volume swaps where the fixed volumes vary from half hour to half hour. These are referred to as sculpted contracts. Unsurprisingly, observed sculpted product prices lie between the flat swap prices and the peak swap prices seen on the AFMA screen on a daily basis. Those prices are for fixed volume fixed price contracts but the sculpted loads for the Integral NSLP are not as flat as flat swaps and are not as peaky as the standard peak swap shapes.

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[21] A useful metric in this context is load factor. This is the ratio of average to peak load. For example, a load factor of 0.5 or 50% indicates that average load is just half peak load.

[22] See http://www.nemmco.com.au/meteringandretail/700-0158.htm

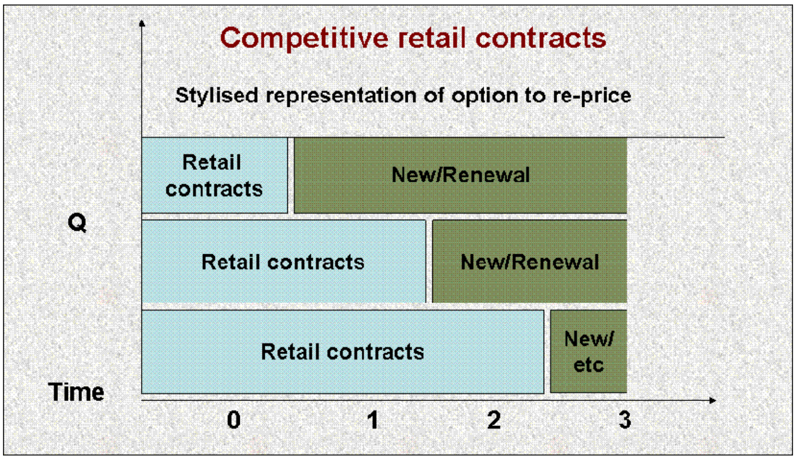
There is some transparency over what small, standard contracts have been trading at to date. However, there is less transparency around the prices of "structured" contracts for larger volumes and related to a specific load shape – e.g. the Integral NSLP.

The hedge contract prices today represent what generators will sell at given their current assessment of the market. However, if market conditions change, hedge contract prices offered will change and could undergo significant step changes.

In the case of contract customers, the problem of uncertainty over future hedge prices is relatively straightforward. This is because retail contracts are of fixed duration, typically in the NEM, around three years.

As a result, given that retail contracts are committed, trading will match these commitments by entering into hedge contracts. While there may be some timing mismatches, the value of these mismatches will be limited by the retailer's energy trading risk management policy or similar instruments governing its energy trading exposures. Importantly, on expiry of competitive retail contracts, or on offering new retail contracts in the future, ordinary retailers have the option to set the price of new retail contract relative to market conditions prevailing at the time.

The graphic below illustrates in a stylised form the zones (in green) where retailers have the option to re-price retail contracts. Assuming three year contracts expiring mid year, this means that a little under half the portfolio can be re-priced over a three year period.



In the case of default customers, however, there is uncertainty over the duration and thus the quantity and value of supply commitments. This is discussed further in section 4.7 below.

From a risk management perspective, the important point is that it is not sufficient to use current hedge prices in establishing the appropriate WTP. Instead, judgments need to be made about future hedge prices. For this reason, a prudent retailer will need to consider not only an analysis of hedge prices. It will also need to consider an analysis of the costs that drive the value of hedge prices – the long run marginal cost of new entrant generation (LRMC).

4.5.1 LRMC

The LRMC of new entrant generation provides an alternative to, or benchmark for, the estimated hedge costs (for sculpted hedges) associated with meeting a forecast NSLP. The theoretical LRMC possesses a number of characteristics which make it a potentially valuable proxy in that it:

- Gives an indication as to the price to which a new entrant generator would require to enter the market (and fully recover the cost of generating its output);
- Indicates the prices to which existing generators could theoretically price towards without attracting new capacity to the market;
- Indicates a theoretical long term level for forward prices (i.e. can potentially reflect the long end of the forward curve); and
- Is likely to be influenced by the level of excess capacity that exists in a market, as well as barriers to entry and competitive conditions.

While these characteristics make LRMC a useful comparator and benchmark for the majority of the potential costs associated with meeting the NSLP for a regulated retailer, its calculation and application need to be carefully conducted.

The need for its careful consideration of how LRMC is estimated is further emphasised because of its use in the previous IPART determination as the fundamental basis for the energy purchase component of its regulated retail tariff. The current regulated retail tariff review necessitates consideration of the long run marginal cost of electricity generation from a portfolio of new entrant generation.

Later in this report we consider the concept of LRMC in electricity generation; as a concept, its effect on pricing and new entry into the market, its estimation, and its use in previous and contemporary reviews. We comment as to whether LRMC was used appropriately in the previous determination, and a suggested approach for considering long run marginal cost in meeting the objectives of the current review – in particular the need for retail tariffs (and hence the EPCA) to be cost reflective by 30 June 2010.

4.6 Energy risk management (ERM) and transactions costs

Depending on a range of factors, liquidity in the hedge market, commercial judgments on the part of the retailer, and the risk appetite of the Board and shareholders, significant trading exposures may remain which are not or not able to be hedged with counterparties, even by a prudent retailer. This reflects the following factors.

- It is not possible to forecast load exactly for each trading interval, reflecting the fact it is consumers, not retailers, who control the quantity of electricity consumed at any given time. Less likely events are the most difficult to forecast. However, peak price ("spike") events are also unlikely events and thus the load forecast error at peak periods is likely to be higher than the average load forecast errors.
- It is not always practicable or economic to purchase hedges against all exposures. An example is where a supply exposure is outside peak price periods and can be managed by the retailer (e.g. controlled load). Within trading limits, a prudent retailer may make a policy decision not to purchase a hedge against an exposure.
- Liquidity or how much the market could be expected to move against a retailer that has to hedge an open position quickly.
- Changes in the value of the trading book over time depending on movements in the forward price curve (mark to market).[23]
- Adverse cover, which refers to the size of the financial buffer an organisation may allocate in order to sustain a series of trading losses over a period.

Further aspects of residual energy trading risk may be described as transactions costs. These relate to counterparty risk and the value of outstanding offers in the market – referred to as 'validity risk'.

Counterparty risk concerns the credit worthiness of the counterparty together with the value, quantity and duration of the financial arrangement. Validity risk (timing risk) relates to the exposure to adverse wholesale price movements between the period an offer to a customer is made, and when it is accepted, and corresponding hedging arrangements put in place.

A prudent retailer will carefully manage the exposure to these risks. An example would be a prohibition on dealing with counterparties whose credit rating is below a minimum threshold in the absence of a bank guarantee. In the case of validity risk, it may be possible to make the offer conditional on there being no material change in wholesale market conditions (or to include conditions which deal with adjustments to prices if certain wholesale market conditions materialise).

Reflecting these and other residual risks, a prudent retailer is required to allocate capital to cover against residual wholesale market risk exposures.

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[23] See for example Integral's Annual Report to 30 June 2005, Note 27 to the Financial Statements, and especially Note 27d.

Capital is required against the possibility that spot trading losses will need to be settled in short order with NEMMCO, or the prudential deposit increased. In the medium to long term, capital is also necessary to ensure the business has sufficient capital reserves to sustain itself even in the event of a material adverse change in the market value (mark to market) of its existing hedge portfolio.

Depending on the estimated size of transactions costs, further capital will need to be allocated and further allowances made, within energy trading margins. To the extent a retailer itself is obliged to acquire bank guarantees to meet prudential requirements, it will also need to recover the cost of these fees.

By their nature, ERM risks cannot be recovered through adjusting the retailer's estimate of its weighted average cost of capital (WACC).[24] Rather, they must be recovered through an appropriate charge on the capital allocated to ERM and transactions costs. In the case of NSW energy corporations, NSW Treasury has issued instructions that capital must be explicitly allocated to energy risk management and transaction risk exposures.[25]

Analytically, the portion of the net retail margin corresponding to ERM and transactions costs should be treated as within the EPCA. However, because ERM and transactions costs are typically captured in the form of a capital charge, they do not form part of a retailer's ordinary expenditure. Rather, they are recovered from a mark up on each unit of energy sold and thus recovered from margins. Accordingly, the quantification of ERM and transactions costs needs to be cross referenced with the estimation of the appropriate level of the net margin, which is the subject of a separate report to Integral by NERA.

4.7 Additional margin for Standard retailers

The basis for estimating the EPCA is the method used for estimating the WTP for a contestable customer on the NSLP. In addition, the estimation of the EPCA needs to be extended because of certain characteristics of standard retail tariffs. This reflects the fact the terms of the standard form customer contract are more onerous to a retailer in that they amount to an ongoing obligation to supply to any customer eligible for a default retail tariff, *at his or her option*.

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[24] WACC is outside the scope of this report. We would propose to use the new entrant retailer WACC estimated for the purpose of a charge on working, fixed and other capital and recovered from retail margins.

[25] See NSW Office of Financial Management: Policy and Guidelines Paper TPP 99-5, dated October 1999.

As noted in section 4.5 above, during the period of the determination, under a standard form contract, the retailer does not have the option to re-price new or renewing retail contracts, to reflect changes in wholesale and retail market conditions at the time. Accordingly, the default retailer is exposed to an additional price and volume mismatch risk.

A further complexity and risk arises due to uncertainty around the quantity of energy that will be sold under standard contracts and hence the quantity and value of the wholesale exposure. The movement of customers between tariff and contract (and also the extent to which new customers opt for tariff or contract) will depend on relativities between the level at which the tariff is set and prevailing retail contract prices. This highlights the difficulties associated with entering into hedging commitments against a floating and uncertain customer base over the price control period. The level of switching and possibly churn[26] will be influenced by the IPART decision, itself, which will in turn influence the intensity of retail market competition.

4.8 Central issues

Given the IPART Terms of Reference and the background information described in the previous chapter, we suggest the central analytical and research problems in determining an appropriate EPCA, and hence the central issues addressed in this report, are as follows.

- How to quantify efficient and prudent hedging, energy risk management (ERM) and transactions costs relative to the 2007/10 period, *for each NSLP.*
- How to take into account the additional risks associated with the obligation to offer standard tariffs to any eligible customer within Integral's NSLP without the protection afforded by ETEF.
- The methodology for estimating new entrant LRMC for Integral's NSLP.
- Reconciling and explaining any quantification of hedging, ERM and transactions costs with the LRMC estimate for the same period.

Each of these issues is considered in more detail below.

[26] The term "switching" refers to customer movements between retailers and between tariff and contract while remaining with the same retailer. The term "churn" refers to customers who switch frequently.

5 Application of the methodology

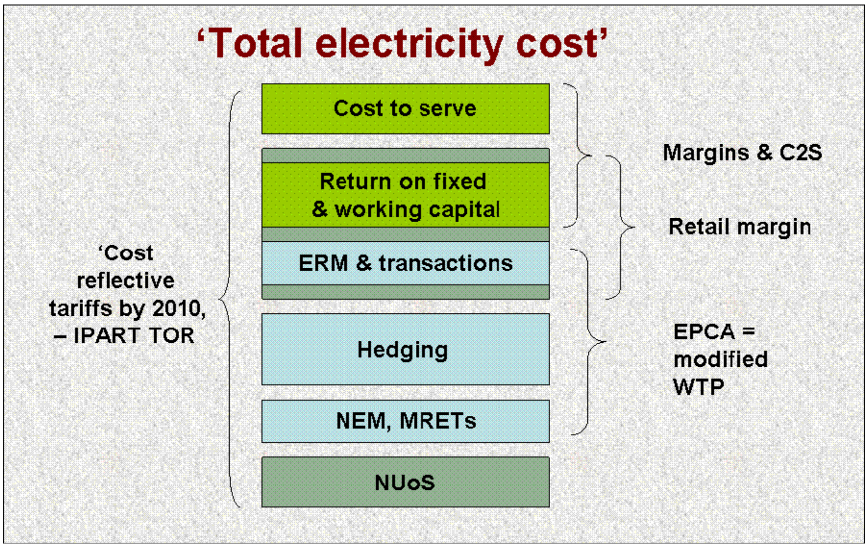
5.1 Introduction

This chapter applies the methodology described in the previous chapter to the Integral NSLP. A key distinction to note is the methodology is being applied to the Integral NSLP but not to Integral's hedging and energy risk management activities in particular. This reflects IPART's Terms of Reference, which focuses on a new entrant retailer rather than for each specific existing standard retailer.

In the course of preparing this report we have reviewed Integral's methodology for deriving the WTP for contract customers settled against the Integral NSLP. To the extent of our enquiries, we are satisfied Integral's WTP process reflects the approach a prudent, efficient retailer would adopt.

5.2 Overview of cost build up

The graphic below illustrates the application of the proposed EPCA methodology described in the previous chapter to the overall build up of retailer costs.



Key points to note are as follows:

- The EPCA includes energy risk management (ERM) and transaction costs, which are typically recovered from a retailer's overall retail margin, reflecting a return on the capital that is required to be allocated to ERM and transactions costs. For the avoidance of doubt, this component of the EPCA recovered from the retail margin covers all energy risk management and transactions costs relating to the retail margin.

- It is assumed the operating costs of the energy trading function are incorporated into the cost to serve analysis.

5.3 Profile

Temperature and humidity have a substantial influence on electricity consumption for air conditioning and heating. This is reflected in the fact NSW electricity consumption is highest during the hottest summer and the coolest winter periods.

Temperatures in coastal areas tend to be moderated by the sea. In the summer, this takes the form of cooling afternoon breezes. In the winter, overnight minimum temperatures are on average warmer.

The table below shows temperature differentials between Sydney[27] and Penrith for the month of December 2005.[28]

December 2005	Sydney		Penrith	
Daily over the month	**Min**	**Max**	**Min**	**Max**
Mean	18.9	28.6	17.0	32.7
Lowest	15.3	22.9	11.8	24.9
Highest	23.3	39.0	22.0	40.1

While the highest temperatures recorded during this period are similar, the mean of the highest daily temperatures for Penrith is significantly higher than for Sydney. Similarly, the difference between the mean maximum and minimum temperatures is less in Sydney than in Penrith. The shape of the Integral's NSLP reflects the greater geographic concentration of Integral's NSLP and the presence of a temperature gradient between western and eastern Sydney.[29]

The relative sensitivity of Integral's NSLP to temperature is illustrated in the exhibit below, prepared by Integral. This exhibit shows the daily load profiles for the Integral, EnergyAustralia and Country Energy NSLPs) after

[27] Temperature data for Observatory hill.

[28] Temperature data for Penrith Lakes.

[29] The data were supplied by the Commonwealth Bureau of Meteorology.

they have been normalised to remove effect of the different volumes associated with each NSLP.

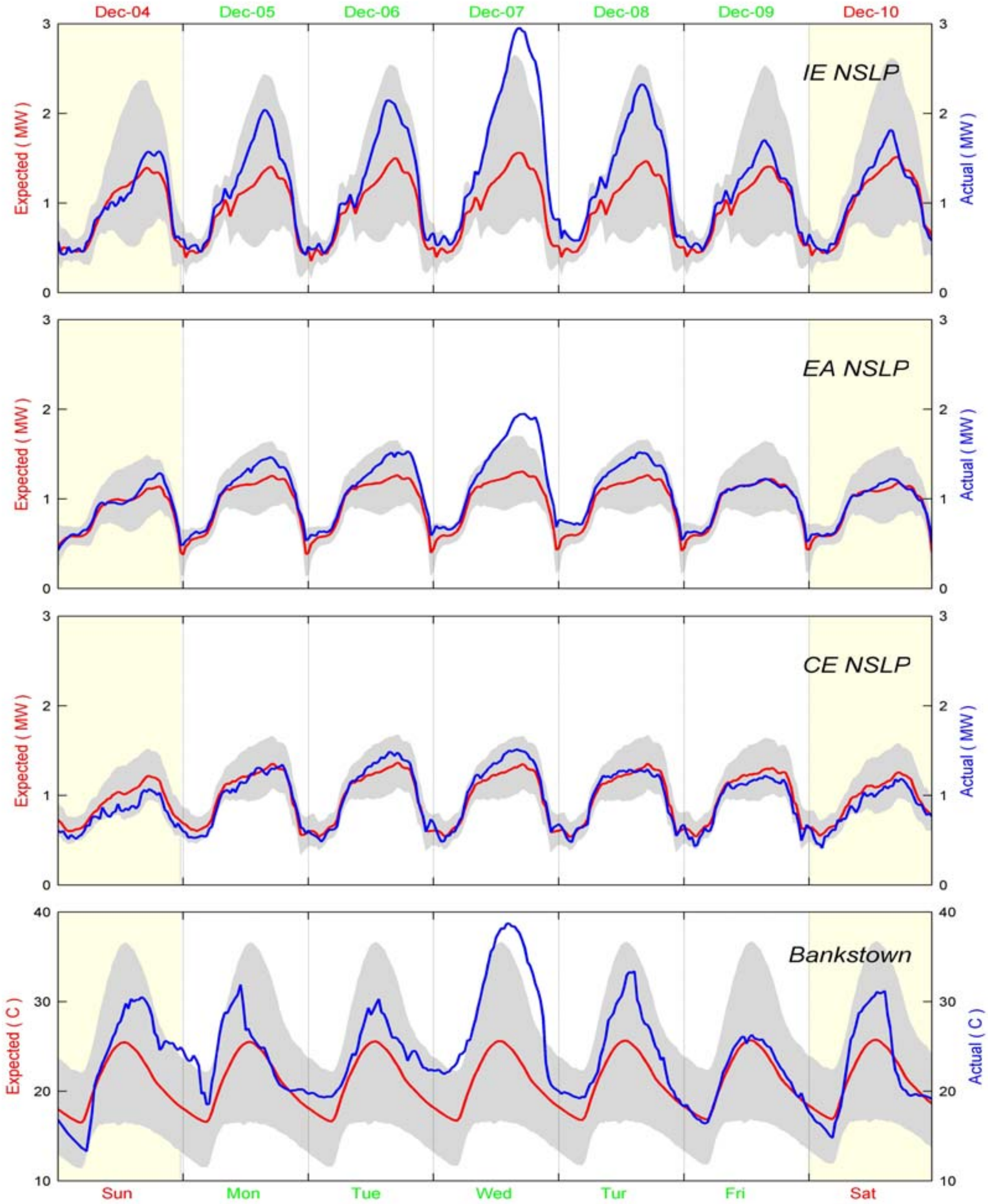
The exhibit compares actual and expected load during one week in December 2005 across three NSLPs and compares these with actual and expected temperatures recorded at Bankstown by the Bureau of Meteorology (BOM). On Wednesday 7th December 2005, the temperature at Bankstown went outside the expected temperature range and recorded a peak of 39°c. This corresponded with load recorded against the Integral NSLP spiking and exceeding the expected range of load outcomes for 95% of the time.

The unusually hot weather on 7th December 2005 also resulted in actual demand exceeding expected demand for the EnergyAustralia NSLP. However, Integral's actual was 190% of expected (i.e. actual divided by expected), while EnergyAustralia's actual was 150% of expected and Country Energy's actual was 115% of expected.

To the extent the data for this period is representative of the different NSLP's on an annual basis[30], it suggests Integral's load shape is characterised by a higher peak relative to annual demand (or a lower load factor). Further, it suggests the Integral NSLP may exhibit substantially higher volatility on a day to day basis relative to the Country Energy and EnergyAustralia NSLPs.

[30] While the data discussed here refer only to a one week period, we have also had the opportunity to review annual data referring to the Integral NSLP and all the available indications suggest the shape has a lower load factor and a higher volatility relative to other NSW NSLPs.

Comparison of volatility of NSLP's for early December 2005[31]



[31] Prepared by Integral Energy.

5.4 Hedge prices

Our review of data provided by Integral suggests the WTP for the Integral NSLP could be expected to be significantly higher than for the other NSW NSLPs (i.e. the cost of meeting the Integral NSLP is higher than for other standard retailers). This reflects:

- The shape of the Integral profile and in particular its lower load factor;
- Integral NSLP has a high correlation with system wide peak demand and high price periods; and
- There is a high level of volatility both around demand and spot prices. Thus load forecast and price risks are greater.

These variables would be reflected in differentials between overall hedge prices for the Integral NSLP relative to other NSLPs. This is because a substantial amount of capacity is required to meet supply obligations relating to the Integral NSLP. However, the corresponding utilisation of that capacity may be low, reflecting the load factor associated with the NSLP. As discussed in section 6.4.2, assumptions around generation capacity factors are an important component in an assessment of LRMC.

The average loss factor for the Integral NSLP is around 8.5%.[32] Accordingly, an additional 8.5% should be included within the EPCA estimate to reflect the volumes that would need to be hedged.

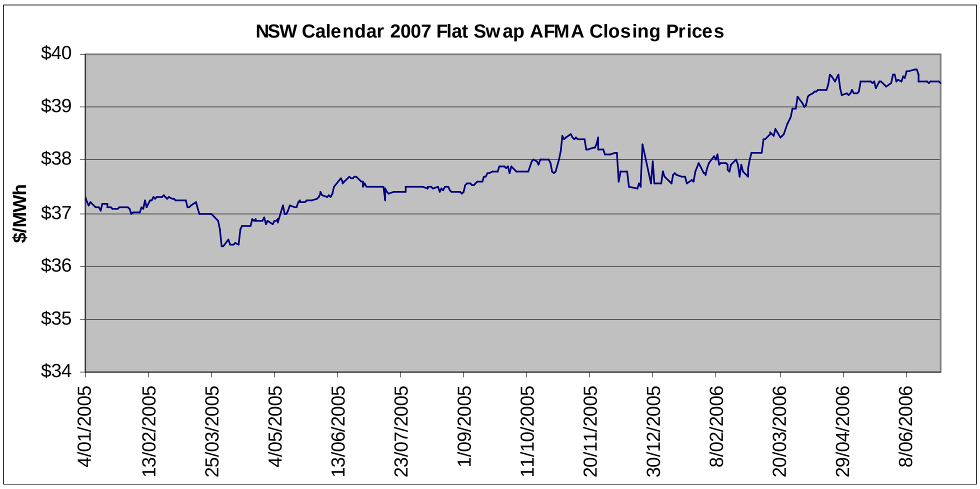
Hedge contract prices today represent what generators will sell at given their current assessments of the market. However, if the market's perception of risks changes, hedge contract prices will change and may undergo significant step changes.

This is illustrated in the chart below that shows movement in the NSW 2007 calendar 2007 Flat Swap prices over the period from 1 January 2005 to 30 June 2006.[33] As perceptions of the risk across the hedge period changes the level of hedges changes.

[32] As advised by Integral Energy. This compares with the 10% average for the NEM overall as identified earlier in section 3.3.1 of this report.

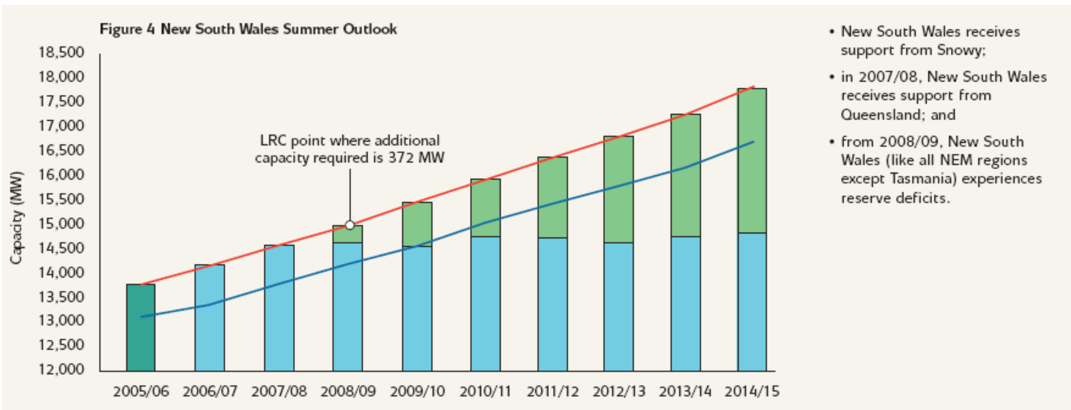
[33] Note that due to the fact actual Cal 07 Swap contracts traded infrequently, daily AFMA closing prices have been used. AFMA publish Bid and Offer closing prices. The data used for the graph represent the "Midpoint" between these two prices.

NSW Cal 07 Flat Swap AFMA Closing Prices for the period 01-Jan-2005 to 30-Jun-06



NEMMCO in its 2005 Statement of Opportunities, suggests there is a possibility NSW will be reliant on imports from 2008/09. This is illustrated in an extract from NEMMCO's report below. Note NEMMCO is suggesting any shortfall from within NSW will be met by imports from other regions, not that there will be a supply shortfall in NSW.

NSW summer outlooks – 2005 NEMMCO SOO



To make a full assessment of where reflective energy supply costs might be in the review period it is necessary to forecast where swaps may be trading through the period 2007 to 2010. In the absence of a forecast of future forward prices it is appropriate to link future supply costs to an LRMC analysis. This is discussed in the following chapter.

5.4.1 *Reconciling LRMC and hedge prices*

While we are proposing that for the purposes of the IPART review it is appropriate to refer to new entrant LRMC as a proxy for forward hedge prices, we acknowledge that new entrant LRMC could diverge from prevailing hedge prices for a range of reasons. For example, to the extent there were surplus capacity, it is possible prevailing hedge prices could be below new entrant LRMC. The interaction between LRMC and market prices is discussed further in section 6.3 below.

It is important to draw clear distinctions between new entrant LRMC, prevailing hedge prices, and cost reflective wholesale pricing relative to the current generation portfolio. An expert report prepared by ACIL-Tasman on 2004 NSW Government proposals for reform of the NSW-owned electricity sector concluded that continuation of a three generator structure over the period modelled would result in 'artificially high' prices relative to a five generator structure. [34] Similarly, an expert report prepared during the ACCC's consideration of AGL's part purchase of Victorian generator Loy Yang also suggested NSW baseload generators exercised market power.[35]

It is outside the present scope to form any conclusions regarding the possible presence or otherwise of market power in the NSW region. However, as discussed in section 7.1 and 7.2, methods for estimating LRMC must take into account the imperfections of real markets, if tariffs are to be set at cost reflective levels.

There is one further factor we suggest IPART needs to consider concerning relativities between any estimate of forward hedge costs and new entrant LRMC – the assumed location of new entrant generation. To the extent substantial elements of the new entrant generation portfolio are assumed to be located in other NEM regions, some allowance will need to be made for inter-regional risks including higher transmission loss factors and the additional costs of hedging between regions. Alternatively, we suggest the LRMC analysis may need to assume the entire new entrant generation portfolio is located in the NSW region, and subject to NSW and not, say, Queensland, input costs.

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[34] See figure 1, page viii of 'Assessment of proposed energy trader scheme in NSW: Report on the effects of the proposed energy trader in NSW on the operation of the National Electricity Market and electricity consumers', dated 1 October 2004, prepared by ACIL-Tasman.

[35] 'The exercise of market power in the NEM: an analysis of price spikes in the NEM, January-June 2003', by Darryl Biggar, dated 23 April 2004.

5.5 Energy risk management and transactions costs

In line with the proposed methodology outlined in the previous chapter, the level of energy risk management and transactions costs in relation to the Integral NSLP will in part be a product of the availability and cost of hedging for the NSLP. It is not possible in the absence of a forecast of hedge costs to discuss the estimation of the energy risk management and transactions costs at this point. This quantification requires a simulation of a range of market outcomes as a basis for determining the amount of capital that would be required to be applied against energy trading and transaction risks, as identified in section 4.6 above.

The discussion of the characteristics of the Integral NSLP above suggests that ERM and transactions costs could be significant. This would reflect among other things a high level of volatility around the load shape and thus a higher possibility of load forecast error relative to a prudent hedge portfolio.

Note that hedge prices, and hence the LRMC analysis as discussed later in this report, need to be related to the specific profile and load factor of the Integral NSLP, for the reasons discussed in section 5.3 above. Under the proposed WTP framework, the NSLP is factored in to the hedge as well as ERM components of the method.

5.6 Additional margin for Standard, government-owned retailers

As discussed under section 4.6 above, in calculating an appropriate EPCA for supplying customers under default retail contracts, an additional margin needs to be included over the transfer price that would be applied to the same customer on a fixed duration competitive contract settled against the NSLP. This reflects the costs to retailers of providing for the higher level of optionality granted to the customer under the default retail contract. Quantification of the additional risks and hence costs associated with a floating customer base is difficult.

There is a further point that may need to be taken into account in assessing the EPCA that would apply to default customers: shareholder constraints on Integral's energy trading exposures. The NSW government, as shareholder, has imposed constraints on energy trading exposures[36].

These constraints could result in the WTP being higher than it would be for a new entrant retailer and a corresponding requirement for a higher EPCA.

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[36] See NSW Office of Financial Management: Policy and Guidelines Paper TPP 99-5, dated October 1999

This is because the limit may oblige the retailer to purchase hedges at a substantial premium relative to the equivalent ERM cost, properly calculated using a capital at risk or similar methodology.

6 Theoretical review of LRMC

6.1 Introduction

In earlier chapters, we proposed that the appropriate method for estimating the EPCA is the method that would be used by an efficient, prudent, new entrant retailer in establishing what is referred to as the WTP for contract customers settled against a customer's unique load profile. A key part of this is estimating the cost of purchasing a portfolio of hedges corresponding to each trading period for the forecast NSLP in question. We noted that there is a lack of information about the future costs of forward prices, and that one way to consider these future forward prices is by estimating the long run marginal cost (LRMC) of generation. IPART's terms of reference require it to consider the LRMC of new entrant generation.

In this section we help create this setting for LRMC in the EPCA by; discussing the theoretical concept of long run marginal cost, its effect on pricing and new entry into the market, its estimation, and its use in previous and contemporary reviews. This includes comments as to the appropriateness of the use of LRMC in the previous determination, and a suggested approach for considering long run marginal cost in meeting the objectives of the current review – in particular the need for retail tariffs (and hence the EPCA) to be cost reflective by 30 June 2010.

6.2 The concept of LRMC

6.2.1 What is LRMC?

In the context of the electricity sector, the concept of LRMC represents the price needed to cover both the fixed and variable costs associated with producing an increment of output over the life of the relevant generation capacity. It also provides for a desired return on the capital associated with that capacity.

The balance between the supply of, and the demand for, generation capacity plays an important role in determining whether the LRMC should reflect the costs associated with new, or existing plant. If there is surplus generation capacity in the market in question, then the LRMC will cover the full costs of incremental output from existing plant. If the demand/supply situation is in balance, the LRMC will reflect costs for new entrant generation. The requirement on IPART to consider the LRMC of new entrant generation presumably reflects the Government's views in relation to demand and supply.

The long run qualifier in LRMC recognises that, in the long run, an investor would seek this price in order for the investment to be profitable and economically rational. While endogenous and exogenous factors[37] may cause short-term deviations from this pricing concept, the LRMC reflects the capital-intensive nature of investment in electricity generation assets; the costs of which effectively become fixed at the point of commitment. The long-run nature of the concept also reflects a point in time whereby all the contributing factors to the plant producing output (i.e. land, labour, capital, energy) are variable.

The LRMC concept is one often utilised when considering investment in utilities because its fundamentals as an *ex* ante tool are relatively transferable, transparent and comparable within, and across, different industries. The concept also makes use of information that is readily available for most proposed investments.

6.3 The effect of LRMC on pricing and new entry

The LRMC concept has important implications for how prices in electricity markets are set, and how participants in those markets behave. Often the link to LRMC may not be explicit to all participants, however its fundamentals will be affecting how generators in particular price their output, and the limits that LRMC effectively places on pricing, given certain conditions. In terms of LRMC's influence on behaviour and pricing, it is possible to observe that:

- New generators would only enter the market if the price they will receive for their output equals their LRMC. If the price is lower than their LRMC, it would not be economically rational for them to enter and they would be better off not investing. They would not recover the full cost associated with producing output in the market. If the price was greater than the LRMC, we would expect them to have already entered the market. Rational buyers would seek alternative suppliers (other than those charging above LRMC) who would accept a competitive return.
- The output of existing plants will be priced close to the LRMC of the next most likely new entrant generator, as demand and supply converge. Existing generators know that new entry is unlikely until the price exceeds new entrant LRMC. If they cannot operate effectively at prices approaching the LRMC of the next most likely entrant, they would be better of selling their assets to the new entrant and the new entrant would be better off buying the assets than constructing new plant. They are likely to be able to price up to LRMC without enticing entry *ceteris paribus*.

[37] Such as transmission constraints, climatic conditions and the availability of fuel.

- Given these factors, in competitive markets we would expect competitive prices to trend toward LRMC. The movement or convergence of the prices will be accelerated where new generation capacity is required to meet demand.
- Non-competitive factors can drive a wedge between prices and the LRMC of the next most likely entrant, particularly in the short term. The size, direction and longitudinal nature of that wedge will depend on the factor inhibiting competition.

6.4 The components of LRMC

6.4.1 Cost parameter estimates

A key group of components that contribute to the estimation of LRMC are basic cost parameters for the generation technology in question. These components are relatively high-level estimates of technical and financial characteristics relating to the plant in question. They typically include:

- **Capital costs** – These are usually presented on a $/kW of installed capacity basis, and reflect the cost of building the physical generation assets. Capital costs typically form a larger component of total LRMC for renewable generation than for thermal generation. Variation in the level of capital costs for particular plant will be driven by factors such as:
  - The scale of the plant: economies of scale may provide decreasing cost per added unit of capacity from a certain level.
  - Demand and supply for that capital equipment: if the capital equipment (or a portion of it) is sourced internationally, demand may put upward pressure on prices, for example. Government policy could potentially influence capital cost through this avenue; if a particular policy encouraged a particular type of generation, and hence drove up demand for related capital equipment.
  - Technological change: improving technology may reduce capital costs for certain technologies over time.
- **Operating and Maintenance (O&M) costs** – O&M costs can be both fixed and variable. The fixed O&M costs are required regardless of the actual operating level of the plant. They would be incurred if the plant were running at 1% or 100% of its capacity. Variable O&M costs are directly related to the level at which the plant operates. It is likely that increased operation of the plant will result in higher variable O&M costs. Variable O&M costs will differ materially for different generation technologies. Open cycle peaking turbines will require higher variable maintenance (depending on its actual use) than coal fired generation for example, which will require more scheduled

maintenance. In terms of modelling LRMC, fixed O&M costs are typically factored in as $/MW installed capacity, with variable O&M being reflected in $/MWh.

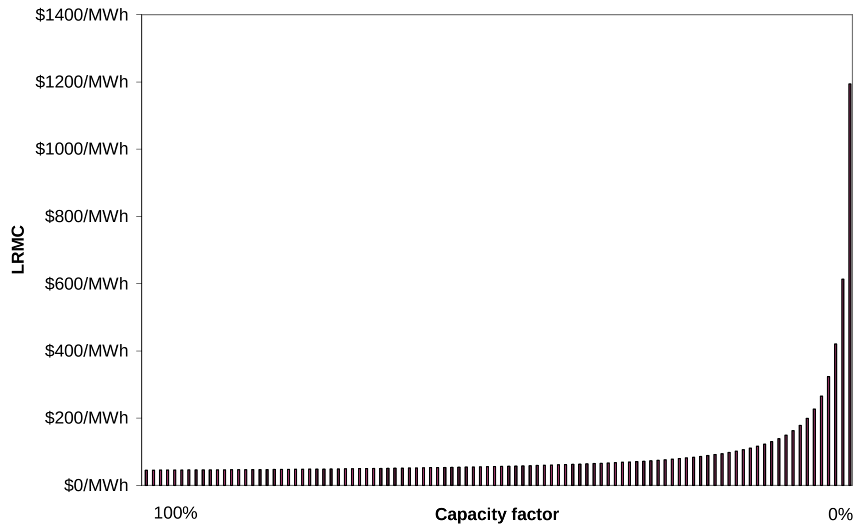
- **Fuel costs** – Most thermal generation technologies require fuel to produce electricity, whether it be natural gas, coal or fuel oil. The price of the fuel will vary on the type of contract the generator can obtain from fuel suppliers. Fuel enters LRMC calculations on a $/GJ of energy basis. For some thermal generators, fuel costs are large contributors to the overall cost of producing an increment of output. Depending on the source of fuel (i.e. domestically sourced, or internationally) the price of fuel can vary depending on demand/supply conditions in that market. This can have significant flow-on effects as to the relative price competitiveness of that generation.
- **Return on capital/capital charge** – as well as seeking to recover the cost of the capital equipment, an investor will seek a suitable return on that investment. A weighted average cost of capital (WACC) is typically the method for calculating the required return on capital. In most LRMC calculations, an annuity is calculated from the capital cost and WACC figures. The annuity represents the annual payment, which will recover the capital cost of the plant, and its required return, over a specified project life. This capital charge/annuity figure typically enters LRMC calculations as a $/MWh cost.
- **Tax** – the return the investor will be seeking from the generation plant will be post tax, and hence we need to allow for corporate tax in terms of what needs to be recovered from a LRMC. As with the capital charge, tax typically enters LRMC calculations as an annuity – spread over output each year of the plant life.
- **Efficiency** – one of the key operating characteristics of the plant is its efficiency. Efficiency represents the relationship between fuel input required, and the resulting electricity produced. More efficient generation plant produces electricity from a smaller amount of fuel input, than would a less efficient plant. Advanced gas fired combined cycle turbines are more efficient than most coal fired power stations for example. In terms of cost though, it is often the case that more efficient generation technologies require less fuel, but the fuel is relatively expensive.

6.4.2 *Capacity factor*

The other key factor in determining LRMC estimates is the capacity factor of the relevant generation technology. In simple terms, the capacity factor is the proportion of the time that the plant is in operation. The capacity factor allows for periods when maintenance or other scheduled outages mean that the plant is not producing output, or is producing sub-optimally.

The capacity factor is a key driver of LRMC because it determines the volume of output over which the costs (outlined above) are allocated. A lower capacity factor means the costs associated with generating the electricity are spread over a lower level of output. To illustrate this, the figure below shows how LRMC as the capacity factor is varied for a hypothetical combined cycle gas turbine.

LRMC variation from changing capacity factor – hypothetical CCGT



In reality, a plant would not operate at 100% capacity, as there will always be times when maintenance or outages result in at least a temporary cessation of operation at full capacity. The figure clearly shows though, how the LRMC estimates increase exponentially as the capacity factor falls below approximately 25%.

The potential variability in LRMC as shown in the figure above highlights how important the capacity factor is to a potential investor. Unfortunately, a number of key factors move to make predicting a plant's actual capacity factor with any certainty very difficult. They include:

- **The lumpiness of generation** – the large capital costs associated with investment in electricity generation mean that capacity is typically added in large increments. Generators do not have the ability to easily add/remove small amounts of capacity into a market once the plant is introduced.
- **Competitive response** – while a potential investor in generation has control over their decision to invest, they do not have control over the response of competitors in the market. If the potential investor goes ahead with the decision to invest, there is risk that competitors may adjust their output or prices in response. This could flow through to the ability of the new investor to sell output at a price they deem acceptable, and hence the profitability of the new investment.

- **Technological change** – the potential new entrant will need to consider how long they believe their plant will be technologically suitable for the market, and how changing technology may affect its ability to offer competitive output over time.
- **Load shape and load level uncertainty** – these two factors are pivotal in determining just what the potential investors' capacity factor will be. The fact that both the shape of the load they will potentially supply and the level of load are uncertain, add material risk to the investors decision. A higher than expected load, and a more volatile load could easily contribute to much higher costs of supply, and could even result in a generator needing to purchase additional electricity from the pool, or from other generators, in some circumstances.

Generators will take account of these uncertainties in pricing output, and hence in their estimate of LRMC. The uncertainties simply reflect the fact that information in the market is imperfect, and this accords risk to potential investors. They will seek to be compensated for taking on that risk, unless another party is better placed/willing to absorb some/all of that risk (for a price).

These market realities must be accounted for in any reasonable estimate of the LRMC of new entrant generation. The most effective method is to model the market allowing for the new entrant generator. The model should account for the factors described in the bullet points above to arrive at the capacity factors that could reasonably be expected by a profitable new entrant generator. A new entrant generator must enter a 'real world' market, with all the imperfections found in the 'real world', and the estimate of LRMC must be such that the new entrant earns a reasonable return on its investment at that estimated price.

In sections that follow, we consider how capacity factors and subsequent new entrant LRMC values have been determined in the previous IPART determination. We provide comment on our view of the appropriateness of that methodology in terms of its ability to capture all the desired components of the energy purchase cost.

6.5 Estimating LRMC

In this section we consider how the LRMC estimates were derived for the previous determination. We do this by looking back at the directives issued to the Tribunal and its consultants, by benchmarking the key cost parameters used in the analysis, by looking at what the underlying methodology is claimed to produced, and by looking at what we believe the results actually estimate.

We then present a more 'greenfields' approach to the development of a realistic new entrant LRMC methodology. It is this suggested methodology which would potentially act as a proxy for hedging costs in the formation of an EPCA, as a contribution to the overall regulated retail tariff.

6.5.1 The previous IPART determination

The previous IPART determination[38] adopted a particular interpretation of LRMC in helping establish an estimate of the energy purchase component of the overall regulated retail tariff. The terms of reference for the determination required the Tribunal to consider LRMC, as opposed to a market price for electricity. The key matter identified in terms of the energy purchase component was the need to include:[39]

"…an allowance for electricity purchase costs based on an assessment of the long-run marginal cost of electricity generation, given the characteristics of the demand of customers remaining on regulated tariffs"

IPART engaged IES as consultants for the LRMC component of the study. They were directed to estimate the LRMC for the regulated retail load of New South Wales retailers, and to: [40]

- Use a forward looking analysis that considered the impact of changing demand on the cost of incremental generation capacity.
- Include any specific requirements relevant to greenhouse gas.
- Emphasise the supply price of new generation capacity.
- Consider whether hedging costs should be included in the calculation (and to estimate the appropriate level of hedging costs, if it was determined that they should be included).

In doing so, IES sought to replicate the current regulated load and to create the most efficient generation plant mix to cover that load. The directive to emphasise on the supply price of new generation capacity was interpreted by IES to mean that the most efficient generation plant mix should come from new entrant generation capacity.[41]

In its analysis, the Tribunal provided some context by noting the probable need for a new phase of electricity generation capacity investment in New

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[38] *"NSW Electricity Regulated Retail Tariffs 2004/05 to 2006/07 – Final report and determination"*, Independent Pricing and Regulatory Tribunal of New South Wales, June 2004.

[39] ibid, p. 28.

[40] ibid, p. 37.

[41] *"The long run marginal cost of electricity generation in New South Wales. A report to the Independent Pricing and Regulatory Tribunal"*, IES Intelligent Energy Systems, February 2004, p. 2 – 6.

South Wales. It noted that key stakeholders recognised the need for retail tariffs to be set at levels that would facilitate this investment and inferred that price signals to promote such investment could be reflected in its methodology via the assessment of the LRMC for electricity generation.

In establishing new entry costs for new generation plant in the portfolio (prior to the modelling of LRMC), IES noted the importance of fuel availability in determining the lowest cost new generation available, and that in New South Wales this meant that the types of generation plant to be considered were: black coal thermal power stations, CCGT and OCGT.[42]

IES produced its new entrant energy estimates[43] using some key cost input parameters for thermal (coal) generation, combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT). It provided low and high bounds around central (medium) estimates for each of the key cost parameters. We have produced some analogous key input figures, based on information collected from the public domain, and from contact with the industry. [44] The comparison of the key parameters is shown below.

IES and alternative central cost parameter estimates[45]

IES estimates			
	Thermal	**CCGT**	**OCGT**
Capital costs ($/kW)	$1,610	$962	$714
Variable O&M ($/MWh)	$5	$4	$3
Fuel ($/MWh)	$12	$25	$45

[42] ibid, p. 2 – 6.

[43] It uses this term to differentiate between estimated new entry energy costs without modelled capacity factors, and the LRMC value determined subsequently which have capacity factors determined via linear programming.

[44] Estimates produced by Simon Hope, Senior Managing Economist at LECG. Estimates henceforth referred to as the alternative estimates.

[45] *"The long run marginal cost of electricity generation in New South Wales. A report to the Independent Pricing and Regulatory Tribunal"*, IES Intelligent Energy Systems, February 2004.

Our estimates			
	Thermal	**CCGT**	**OCGT**
Capital costs ($/kW)	$1,400	$1,000	$714
Variable O&M ($/MWh)	$3	$3	$5
Fuel ($/MWh)	$12	$25	$44

The key parameter estimates are very similar, with only minor differences in fuel price estimates. The variation of interest is in the variable O&M costs. Our estimates reflect the high maintenance costs associated with the starting of OCGT plant compared to thermal plant.

The IES report takes these cost parameter estimates, and using some assumptions about WACC and fuel efficiency produces some preliminary estimates of new entrant energy cost based on a 100% **hypothetical** capacity factor. It then varies the capacity factor to see where the energy cost curves cross for the different technologies. This results in three high level estimates of new entrant energy cost based on some indicative capacity factors (indicative in that they do not reflect the load they are required to meet). The table below compares the IES estimates to our estimates, which, for this exercise use the same indicative capacity factor, WACC and efficiency assumptions.

New entrant energy cost estimates, based on IES indicative capacity factors (not modelled) and WACC:

	Thermal	**CCGT**	**OCGT**
IES estimates[46]	$36.2/MWh	$50.9/MWh	$109.0/MWh
Our estimates	$36.9/MWh	$54.5/MWh	$111.7/MWh

* Assumes 9.5% real post tax WACC, capacity factors of 100%, 55% and 14% respectively for Thermal, CCGT and OCGT plant.

When adopting the indicative IES capacity factors and the WACC, the relative new entrant energy cost estimates are not materially dissimilar over the various technologies, with our estimates tending to be slightly higher overall.

[46] "*The long run marginal cost of electricity generation in New South Wales. A report to the Independent Pricing and Regulatory Tribunal*", IES Intelligent Energy Systems, February 2004.

Some of the difference will relate to an escalation in the key input parameters since the IES estimates were produced in 2004.

We can also provide a wider benchmark of the IES figures against others produced for the Australian electricity market. In its February 2005 report on NEM generator costs[47] ACIL Tasman produced LRMC estimates (in 2003/04 dollars) for new entrant gas and coal fired generators across 17 sectors in Australia. While they adopt a cash flow modelling technique, the key components are relatively comparable to those adopted in the IES estimates, and in the high level alternative estimates.

The ACIL Tasman estimates for the 17 zones are shown in the table below. Overall there are few material differences in terms of the relative magnitudes of the key input variables, with some of the differences likely to be accounted for in the classification of where certain costs should be attributed.

The key differences arise in terms of the assumed capacity factors and the WACC adopted by each. ACIL Tasman derives its capacity factors through links to fuel input prices; under the assumption that the higher the fuel price, the higher the SRMC and the lower the capacity factor.

[47] *"Report on NEM generator costs (Part 2) Short run marginal cost of existing generators and short and long run marginal cost of new gas and coal fired generators in each of 17 zones"*, Prepared for the Inter Regional Planning Committee (IRPC) and NEMMCO, ACIL Tasman, February 2005.

ACIL Tasman new entrant LRMC estimates

Zone	Assumed capital cost per KW installed	Assumed Capacity Factor	Fuel cost	O&M	Capital cost	Tax cost	Total costs at station (sent out)
CCGTs			CCGTs ($/MWH in 2003/04 prices)				
NQ	$850	75%	$26.93	$4.17	$10.20	$1.92	$43.22
CQ	$850	75%	$22.75	$4.17	$10.20	$1.92	$39.04
SEQ	$850	75%	$21.89	$4.17	$10.20	$1.92	$38.18
SWQ	$850	75%	$20.23	$4.17	$10.20	$1.92	$36.52
NCEN	$850	50%	$28.44	$5.11	$15.30	$2.88	$51.73
SWNSW	$850	50%	$26.64	$5.11	$15.30	$2.88	$49.93
CAN	$850	50%	$30.17	$5.11	$15.30	$2.88	$53.45
SNY	$850	50%	$27.36	$5.11	$15.30	$2.88	$50.65
NVIC	$850	60%	$30.17	$4.64	$12.75	$2.40	$49.96
LV	$850	60%	$21.96	$4.64	$12.75	$2.40	$41.75
MEL	$850	60%	$23.54	$4.64	$12.75	$2.40	$43.33
CVIC	$850	60%	$22.46	$4.64	$12.75	$2.40	$42.25
NSA	$850	65%	$27.22	$4.76	$13.42	$2.53	$47.93
ADE	$850	65%	$26.35	$4.76	$13.42	$2.53	$47.06
SESA	$850	65%	$24.48	$4.76	$13.42	$2.53	$45.19
TAS	$850	65%	$30.17	$4.46	$11.77	$2.21	$48.61
Coal Fired			Coal fired plant ($/MWH in 2003/04 prices)				
NQ	$1,400	90%	$8.77	$5.49	$15.39	$2.96	$32.61
CQ	$1,400	90%	$8.31	$5.49	$15.39	$2.96	$32.15
SWQ	$1,400	90%	$6.46	$5.49	$15.39	$2.96	$30.30
NCEN	$1,400	87%	$7.38	$5.64	$15.92	$3.06	$32.01
SWNSW	$1,400	87%	$9.23	$5.64	$15.92	$3.06	$33.85
LV	$1,800	91%	$5.81	$4.98	$20.00	$3.85	$34.64

ACIL Tasman notes in its report that the primary reason for its estimates of New South Wales new entrant LRMC being lower than the IES estimates of new entrant energy cost is a considerable difference in the assumed WACC. IES use a real WACC of 9.5% in its central scenario, whereas ACIL Tasman assumes a real post tax WACC of 6.31%. If ACIL Tasman used the 9.5% real WACC, and the assumed capacity factors were made comparable, their estimates would be very close to those produced by IES.[48]

It is interesting to compare these new entrant LRMC estimates to those in the New Zealand market. We have produced high-level new entrant estimates based on capacity factors (assumed rather than modelled) analogous to those

[48] ibid, p.77.

adopted in the IES and ACIL Tasman estimates above. They are shown in the table below in Australian dollars.

Estimates of New Zealand new entrant energy costs (with assumed capacity factors)

	Capital cost	Fuel	Total O&M	Tax	Total cost
Coal	$1,743/kW	$27.5/MWh	$5.4/MWh	$4.7/MWh	$60.1/MWh
CCGT	$689/kW	$38.1/MWh	$5.3/MWh	$1.9/MWh	$60.7/MWh
Wind	$1,743/kW	n/a	$1.1/MWh	$4.7/MWh	$61.3/MWh
Hydro	$2,988/kW	n/a	$5.1/MWh	$8.1/MWh	$66.3/MWh

*Assumes capacity factors of 87% for coal and 50% for CCGT. These are similar to those used in the IES/ACIL comparisons above. They are not modelled on the expected New Zealand load.

*Assumes an exchange rate of $1NZ/$0.83AU.

One key difference highlighted in the table is the level of fuel prices for coal and CCGT generation, with the relative New Zealand values being considerably higher than for their Australian comparators. There are also some differences in corporate tax (with the New Zealand rate being 3% higher than that for Australia) and the assumed WACC. In New Zealand, a post tax real WACC of 7.5% has been observed in the market for the four major generators. Adopting a WACC similar to that used in the IES study would add a material increase to the estimated new entrant costs for New Zealand shown above.

Using these new entry costs, IES assumed that the cost of meeting the regulated retail load should be optimised by the development of a linear programming model to optimise the generation plant portfolio.[49] The optimised portfolio was designed to meet a segmented load duration curve, effectively by minimising the short run marginal costs (determined by IES to be fuel costs) for each segment. As well as the operating costs, the approach minimised the associated capital costs with meeting that segment by assuming that investment in plant is infinitely divisible.

[49] *"The long run marginal cost of electricity generation in New South Wales. A report to the Independent Pricing and Regulatory Tribunal"*, IES Intelligent Energy Systems, February 2004, P. iii.

As well as minimising costs, the linear programming approach also assumed revenue neutrality, being defined as total generator revenue being constricted to exactly match total costs so that no 'producer surplus' existed.[50]

The derived revenue neutral marginal costs were then used to determine average marginal costs for the various time sectors (i.e. peak, shoulder and off peak) inherent in the load duration curve. IES then uses these values to determine an average LRMC value for new entrant generation.

The optimisation approach adopted by IES has a number of important consequences in that:

- It essentially assumes that the segmented load profile being matched is known and certain i.e. there is no volatility or uncertainty associated with demand. For demand to be matched at the smallest increment by optimised generation, it is assumed to be known in advance.
- The generation plant that is optimised is assumed to be completely variable/divisible[51] - infinitely small increments of generation can be added instantaneously for all types of generation. This assumption also effectively implies that fuel is instantaneously available to provide the increased increment of generation capacity.
- The entry of generation occurs in these infinitely small increments. Equally, reductions in capacity to meet load are made in the same small increments.

In addition, the IES report is clear in its response to IPARTs' request for consideration of whether hedge costs should or should not be included in the calculation of energy costs. It states that:[52]

> *"…in the context of this study, the issues of competition, pricing and risk were not seen as determinants of the long run marginal costs of physically supplying an increase in demand. Contributing factors to prevailing discount rates are the market risks and level of competition specific to the market in which generators operate, as markets where generators are able to exert some market power will ultimately result in increased returns. Therefore aspects of risk, competition etc. were expected to be implicitly incorporated into the calculation of the LRMC via the discount rates used."*

[50] ibid. p. 2 – 13.

[51] ibid. p. 2 – 14.

[52] ibid. p. 2 – 5.

The conclusion postulates that as well as hedge costs, the IES LRMC estimates effectively include aspects of risk, competition and pricing via the discount rates (WACC) used.

This conclusion flowed through to the IPART Tribunal which, at least in part, based its decision not to include an explicit allowance for hedge costs on the IES observation that they were effectively allowed for in the LRMC calculation via discount rates (that is, WACC). IPART noted in its final determination that generators and retailers were of the opinion that hedge costs should be allowed for as an explicit item and were not allowed for in the IES calculations of LRMC.[53]

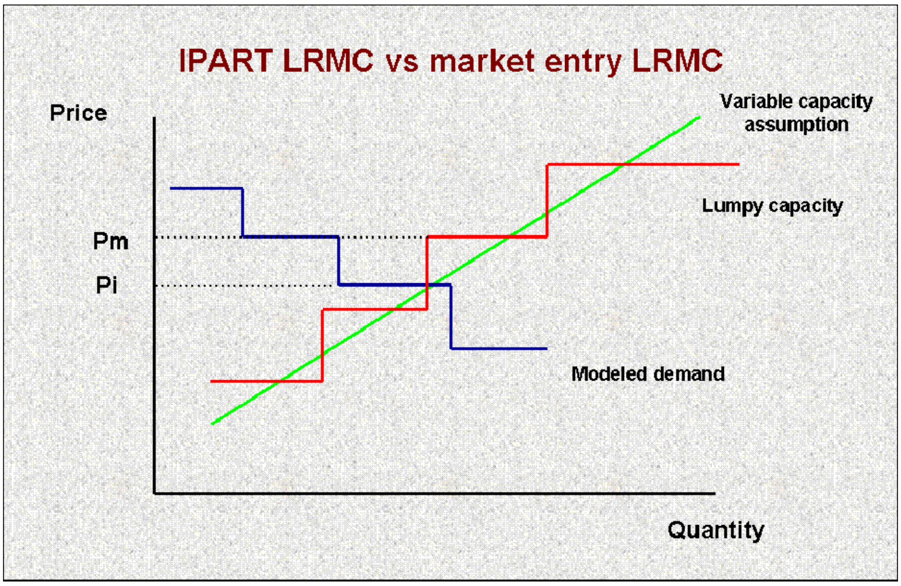
Having considered the assumptions underpinning the IES calculation of LRMC, and the consequences borne out because of those assumptions, we have identified some important limitations in terms of what the LRMC values produced actually encompass, as opposed to their proposed coverage and definition. These issues primarily relate to the linear programming approach, which optimises new entrant generation to the segmented load duration curve. We believe that the approach:

- Understates realistic entry prices for new entrant generation, because it ignores the fact that generation is inherently lumpy, rather than being infinitely divisible. Generation capacity enters the market in typically large increments, as there tend to be economies of scale in building generation. It is not realistic to assume that generation plant can be added/removed from a wider generation portfolio in infinitely small increments.

  This situation is shown in the stylised diagram below. The IES modelling assumes that the supply of generation is essentially a linear function, able to be added to meet load in infinitely small increments. The pricing of this supply is thus represented, when matched to the assumed, known demand at the price labelled Pi. In reality, because of the lumpiness of generation capacity, the red line represents the supply curve for a realistic market situation. The owners of that capacity will be taking into account the fact that their capacity enters in lumps, and that this adds uncertainty around the actual capacity factor their plant will face. The market price resulting from the lumpy supply and assumed demand is likely to be around the higher and not the lower price on the diagram below.

[53] *"NSW Electricity Regulated Retail Tariffs 2004/05 to 2006/07 – Final report and determination"*, Independent Pricing and Regulatory Tribunal of New South Wales, June 2004, p.39.

Lumpy vs. infinitely divisible capacity



- Ignores the fact that the load to be met by the new entrant generation is not known, and it is uncertain in nature. Generators will undertake an assessment of the likely load it will help meet, but there are uncertainties surrounding competitive response, the longevity of technology etc. Generators will take these considerable uncertainties into account when pricing their output (or assessing their LRMC). The prices they seek will reflect the uncertainty inherent in realistic markets, as opposed to an unrealistic but optimal market where demand is known and generation capacity is available to exactly match that known and un-volatile demand.
- Ignores the fact that because of the uncertainty that occurs in a realistic market situation, hedge costs and risks will be an additional cost to a retailer looking to secure capacity to cover a regulated retail load. An efficient retailer will look to manage the risk surrounding their purchases by internally hedging or buying some output from the spot market for example. The cost, and risks associated with these purchases, plus the purchases from new entrant generators will more accurately reflect the real energy purchase costs facing retailers in a realistic market situation.

Hence, the IES methodology understates the LRMC for new entrant generation, and because it ignores hedge costs/risk etc. does not accurately represent the realistic energy purchase costs a retailer will face in looking to match its regulated retail load.

7 Development of a cost reflective EPCA

7.1 An alternate approach for the current retail tariff review

To meet the Government's requirement that tariffs are cost reflective by 2010, the key issues identified in previous section concerned the IES approach must be remedied. The energy purchase component of the tariff must be set at a level that reflects the total costs to an efficient retailer of purchasing energy to satisfy their regulated retail load. For the reasons discussed above, we believe that the previous IES study understated the cost of new entrant generation at $47/MWh.[54]

In terms of an alternate methodology, we recommend that the following key components are reflected in the analysis of LRMC, to ensure the energy purchase component is cost reflective:

- Any changes to the key cost parameters that have arisen since the previous determination (i.e. how new entrant generator energy costs have changed).
- Modelling of capacity factors through looking forward and modelling new entry (of generation capacity), as it would happen in reality. This means considering how and when planned/committed generation would enter the market, given its lumpy nature. It also means considering the other factors affecting capacity factors such as how long it is assumed that the various technologies remain competitive, as well as the competitive response expected as a result of new entry.
- A reflection of the true new entrant supply curve when considering new entrant generation i.e. it must account for key features of generation in a realistic market setting including the fact that generation enters (and exits) from the supply curve in large increments, rather than being infinitely divisible.
- A recognition and incorporation of the demand to be met being uncertain and volatile. Variations in demand should be incorporated in the model to represent the potential uncertainty in the level of demand to be met.
- A subsequent demand/supply match which reflects the fact that generators will need to allow for this uncertainty and volatility, and that market prices will reflect the risk that generators must absorb if

[54] "*NSW Electricity Regulated Retail Tariffs 2004/05 to 2006/07 – Final report and determination*", Independent Pricing and Regulatory Tribunal of New South Wales, June 2004, p.77.

they are to maintain a presence in the market. The capacity factors ascribed to new entrant plant should reflect this uncertainty, and should reinforce the likelihood that demand will not exactly match supply at all points along the spectrum.

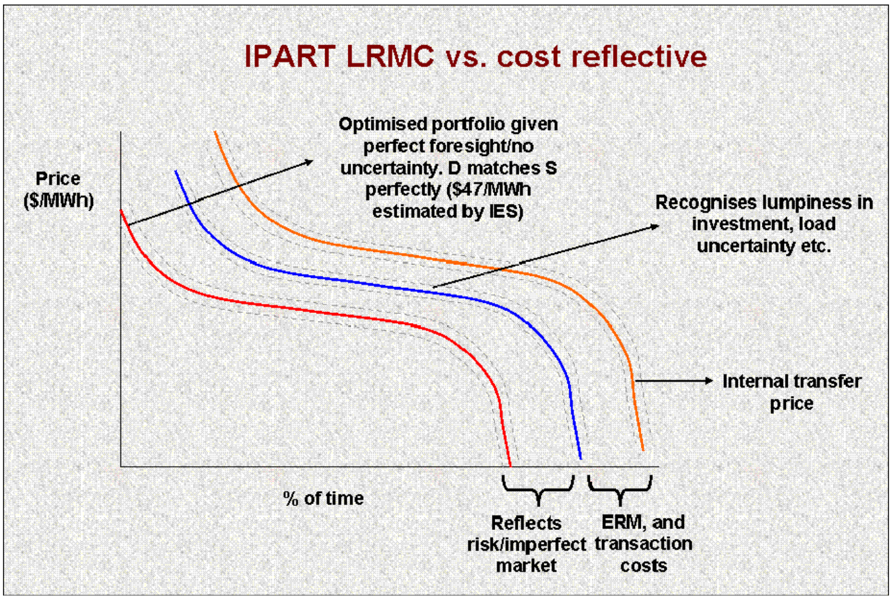
- Hedge costs, transaction costs and risk are included as additional costs to a retailer (i.e. covered as ERM and transaction costs as described in earlier sections of this report) looking to secure capacity to cover a regulated retail load. As we noted earlier, an efficient retailer will look to manage risk surrounding their purchases by internally hedging or buying some output from the spot market for example. These costs need to be allowed for to help reflect the full real cost to retailers of purchasing energy to meet their regulated retail load.
- Losses must be taken into account, as the amount paid by the retailer must compensate for energy lost in transmission and distribution.

Without the inclusion of these key components in the IPART analysis of LRMC and the total realistic energy purchase costs for retailers in New South Wales, we believe that the final regulated retail tariffs set will not be cost reflective.

7.2 Incorporating LRMC into cost reflective tariffs

The IEC methodology adopted by IPART in the previous determination calculates the prices necessary to cover the total cost of an optimal generation portfolio, assuming perfect foresight and completely variable generation capacity. The methodology produced prices at various points on the load duration curve, and averaged these prices to arrive at the $47 per MW figure adopted by IPART.

In the stylized diagram below, we have represented this profile of prices as the red line closest to the axis. IES allow for variations in the costs of components (low, medium, high), and we have shown this variation as dotted black lines either side of red line.



As discussed in the previous section, new generators will enter the market only when prices in the market are sufficient to cover their LRMC, taking into account the imperfections of real markets. These imperfections include lump investment (rather than perfectly variable capacity), uncertainty as to future demand, and demand volatility.

Hence, the LRMC of new entrant generators (or the prices in the market sufficient to cover the LRMC of a new entrant) are higher than those produced by the IES methodology (with its unrealistic assumptions about perfect foresight and perfectly scalable generation). We have represented the LRMC as an input for cost reflective tariffs as the blue line in the above diagram. The dotted black lines reflect the ranges associated with the estimates for each cost component (e.g., capital cost). This blue stylized curve represents the prices a portfolio of new entrant generators would require in order to profitably enter the market. Because these prices reflect the opportunity cost of generation in the market (see section 4.2), this curve represents the prices all generators (existing and new) would expect to receive so as to recover the full economic cost of generation given the average NSLP for all retailers.

As generators can reasonably expect that prudent, efficient retailers will enter into sculpted hedge contracts, the LRMC estimates (as represented by the blue line in our diagram) would reflect the sculpted hedge prices a retailer could expect to pay for hedges sculpted against the average NSLP for all retailers.

The LRMC of new entrant generators, however, does not reflect the total costs a new entrant retail would incur in purchasing energy to match its actual NSLP. There are additional costs that must be met. These costs include:

- The cost of matching the actual NSLP of the retailer. The retailers load may be more volatile or and have higher peaks on average, meaning the prices it pays will be higher than average (see chapter 5).
- The cost of energy lost in transmission and distribution (see section 5.4)
- The cost of hedging, risk management, and transaction costs (see section 5.5)
- The additional margin as a default retailer (see section 5.6).
- Other costs, such as NEM fees, NUoS charges etc (see section 7.2.1)

The orange line on our graph reflects the total costs the retailer would incur in order to meet its retail demand. These are the costs that must be reflected in the regulated tariff is to be "cost reflective" by 2010.

7.2.1 Other costs to be considered

The current IPART review also requires the consideration of other costs that a retailer will face in meeting its regulated retail load. These costs include:

- Generator NEM fees;
- Cost of compliance with 'green' energy options (MRET and GGAS); and
- Retailer NEM charges and ancillary charges.

An allowance for generator NEM fees and other wholesale charges is likely to be best dealt with as an explicit addition to an LRMC estimate. In this manner, they would essentially be treated as 'pass through' items, as they are unavoidable. In the previous determination, and allowance of $0.10/MWh was included for generator NEM fees. The treatment of ancillary charges is also likely to be best dealt with via an assumed addition to an LRMC estimate.

The cost of compliance with 'green' energy options, and the retailer NEM charges however, are more endogenous in nature. In terms of the 'green' energy options, both the Commonwealth Mandatory Renewable Energy Target (MRET) and NSW Greenhouse Gas Abatement Scheme (GGAS) obligations need to be considered. In the previous determination, they were dealt with via an addition of $1/MWh and $2/MWh to the LRMC, for the MRET and GGAS schemes respectively. The need to purchase energy from renewable sources (MRET) and the need to meet greenhouse gas reductions targets may, however, influence the portfolio of energy purchased by a retailer in meeting its regulated retail load. They may purchase a higher/lower proportion of their energy needs from a particular generator to satisfy their MRET and GGAS requirements, and this may differ from their purchases in the absence of such schemes. For this reason, it is suggested that when the LRMC analysis in conducted that the potential for altered energy purchases because of MRET and GGAS is at least considered as a possible endogenous effect, rather than an exogenous and explicit addition to the LRMC estimate.

The retailer NEM charges are based on a retailer's energy purchases (on a MWh basis) and hence should be calculated directly (essentially derived) from the LRMC analysis, which will identify energy purchase requirements for each retailer.

7.3 Proposed Green energy licence condition

The NSW Department of Energy and Utilities released a preliminary issues paper in January 2006 with detailed proposals for a requirement for all licensed NSW retailers to offer a 10% Green Power Scheme. This would replace the current opt in scheme with an opt out scheme. The offer must be made to all small retail customers who request a new supply contract, whether regulated or contestable. Customers will have to make a conscious decision to opt out of the scheme. Customers would be allowed to opt out at any time and revert back to a standard contract without being penalised.

We expect the WTP methodology identified in chapter four above would be applied in estimating the incremental cost of meeting the additional energy purchasing costs associated with the eventual green energy licence condition. In particular, judgments would need to be made around the costs of purchasing or creating green energy products and the possibility of price volatility because of supply-demand imbalances. A higher probability of price volatility may be expected given the relative scale of the purchases that would be obliged under the scheme.

It is likely that a significant ERM component may be required. This reflects a key design feature of the scheme – the right for customers to opt out any time. This introduces significant risk exposures that would need to be managed.

It is understood the incremental cost of energy purchases in order to meet the requirements of the scheme would be above the EPCA. Further, it is also assumed this incremental cost could be determined by retailers on a cost reflective basis. Accordingly, our understanding is the cost of purchasing green energy products over the cost of MRETs and NGACs would be excluded from the estimation of the EPCA for the purposes of setting standard retail tariff.

7.4 Considerations for LRMC going forward – 'keeping up'

Another component of the forward looking nature of our suggested approach for producing cost reflective energy purchase costs involves considering potential price/cost pressures that are likely to affect LRMC for new entrant plant. Failing to take account of these potential price/cost pressures would mean that the regulated retail tariff would not be cost reflective for the duration of the price control period.

While it is acknowledged that there will be differences in opinion as to the magnitude, and in some cases direction, of these price/cost pressures, it seems logical to at least consider them and how these potential impacts could influence an LRMC estimate. Where there is some agreement, or reasonable expectation of pressure, they should be considered in the calculation of forward looking energy purchase cost estimates as part of the cost reflective regulated retail tariffs. Generators who will be affected by these cost/price pressures will themselves be assessing the risk of them impacting on their generation costs.

We have identified a number of key areas where cost/price pressure could be felt in the period to be covered by the terms of reference for the current regulated retail tariff determination.

- **Natural gas prices** – the world market for natural gas is becoming deeper and more diverse. As it develops, prices faced by potential new entrant generators in Australia will be increasingly influenced by international natural gas prices, as well as by domestic resource availability. The increasing dominance of worldwide LNG trade will only serve to exacerbate this trend. While Australian domestic resources continue to provide surety as to the volumes of natural gas potentially available to new entrant generators, wholesale prices are likely to increasingly reflect the opportunity cost of the seller offering that natural gas to the world market. Strong demand growth from developing countries; China and India in particular, will be putting upward pressure on natural gas prices, as the opportunity cost of selling the natural gas in Australia rises. While the large volumes of natural gas available domestically have previously kept price pressure to a minimum (in real terms at least) it is likely that the pressure will increase with world demand growth going forward.
- **Coal prices** – similarly to natural gas prices, the growth in coal trade internationally will mean that prices will be increasingly influenced by the opportunity cost of selling domestically i.e. selling it internationally. China is again a huge potential source of demand for its own electricity generation. Some Australian producers have already taken advantage of these opportunities and have struck deals with large coal users in China. The large volumes being sought may provide upward pressure on coal prices in Australia, as its value on the international market rises. In addition, as historical, lower priced contracts for coal supply in Australia roll off over time, more and more buyers will be exposed to increasing prices, influenced by world demand pressures.

- **Capital costs** – international demand for capital equipment required for new entrant electricity generation will also be an important consideration. Existing estimates of $/kW installed costs for coal, CCGT and OCGT plant could be different to those currently assumed, because of growth in world demand for this equipment, for example. While the demand pressures are likely to be different for different equipment (e.g. world demand for wind turbines is particularly strong), pressures specific for likely new entrants in the Australian market should be identified and included if necessary. The demand for competing uses of much of the capital equipment will also be a factor. Strong world demand for steel used in construction may cause cost pressures for those wanting steel based equipment for electricity generation, for example. Upward pressure on capital costs can be observed in recent reports of substantial increases in the costs of large energy infrastructure projects, for example the NW Shelf expansion and other large energy-related projects in WA and Queensland[55].
- **Exchange rate impacts** – changes in the value of the Australian dollar can also influence the cost of capital equipment for generation, and hence potentially the cost of output from new entrant generation. There will be differences in sensitivity to exchange rate movements depending on the proportion of capital equipment that is imported for each technology, but for most technologies there will be some impact. While it is notoriously difficult to predict exchange rate movements, consideration should at least be given to the magnitude of potential movement in the exchange rate, and the potential impact this could have on capital costs for new entrant generation, and subsequently the cost of their output.
- **Emissions charges** – there has been a large amount of publicity recently concerning the potential impacts of options for dealing with greenhouse gas emissions. It is likely that any form of charge relating to emissions of carbon (one possible option for targeting carbon emissions considered in other jurisdictions), should it be introduced, would have a material impact on the cost of new entrant generation from fossil fuels. It would be useful to consider the likelihood of any such options if it was considered possible that they may be introduced in the period to be covered by the current terms of reference from IPART. The impacts could potentially alter the merit order of new entrant plant, and the LRMC for new entrant generation plant in Australia. For example, a high level estimate[56] shows that a $10/tonne

[55] See for example a current report on the increased costs associated with the NW shelf expansion: http://www.smh.com.au/news/business/soaring-costs-hit-shelf-expansion/2006/09/05/1157222131451.html

[56] Estimate produced by Simon Hope, Senior Managing Economist, LECG.

CO_2 charge on generation from black coal could add around $9/MWh to the price of electricity (from new entrant generation). For new entrant CCGT generation, a high level estimate shows prices could increase by around $3.2/MWh.

The following figures show relative indicative impacts from hypothetical variations in the key inputs (identified above) for new entrant black coal, CCGT and OCGT generation.

The variations are used to show how sensitive high-level estimates[57] of new entrant LRMC are to changes in some of the key inputs. They sensitivities should each be considered in isolation, rather than as additive effects (the combined effects may differ from an aggregation of individual impacts). The variations include:

- +/-10% variation in the assumed capital cost for each technology from a central estimate.[58]
- +/-2% annual growth/decline in fuel input price for each technology from a central estimate.[59]
- $10 and $20 per tonne CO_2 carbon charge on coal and natural gas.
- A +/-15% movement in the $US/$AU exchange rate from a central estimate.[60]

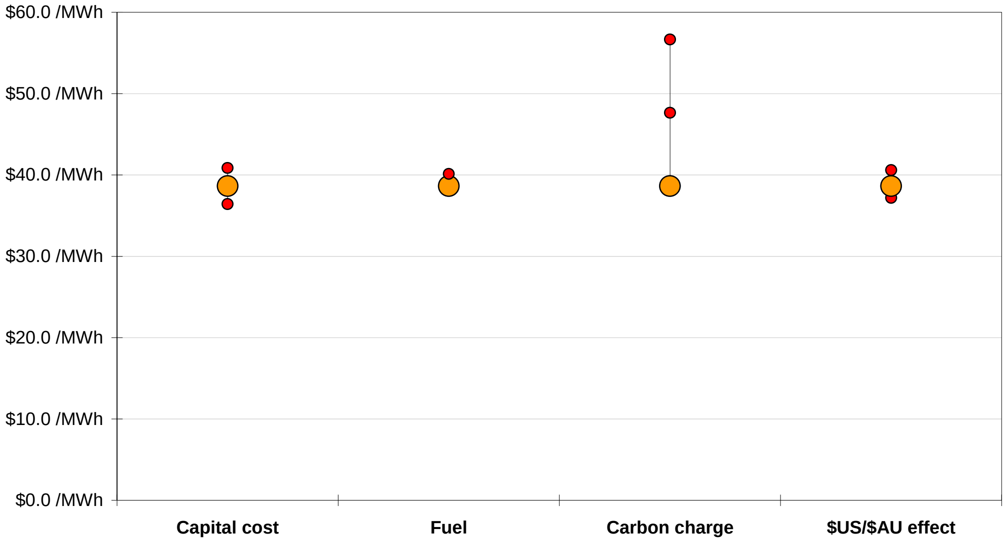
[57] The estimates **do not model capacity factors directly**; they use **assumed** values from observing cross over points on cost curves for the various generation technologies.

[58] Central estimates are $1,400/kW for black coal, $1,000/kW for CCGT and $714/kW for OCGT.

[59] Central estimates are $1.2/GJ for black coal, $4/GJ for natural gas for CCGT and $4.5/GJ for natural for use in OCGT generation.

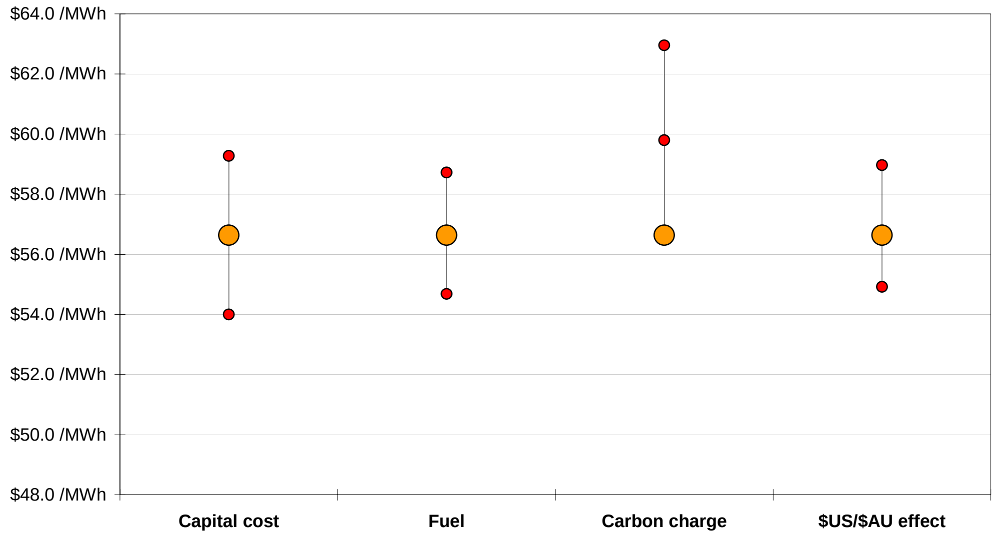
[60] Central estimate of $US0.76/$AU. Assumes 50% of the capital cost for each generation technology is imported (on a $US basis).

Cost parameter variations for black goal generation

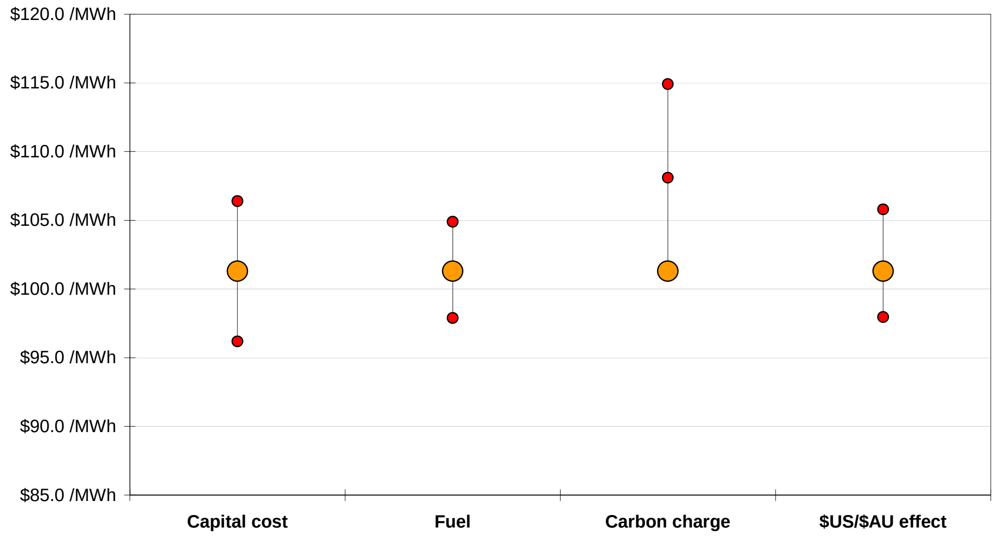


A hypothetical carbon charge will clearly have a relatively large impact on the potential LRMC for new entrant generation from black coal. It has a higher relative level of carbon emission than natural gas, and has a large absolute potential impact because of its relatively low price (compared to estimated new entrant CCGT or OCGT generation). Changes in capital costs also have a material impact.

Cost parameter variations for CCGT generation



Cost parameter variations for OCGT generation



A hypothetical carbon charge still has a large potential impact on CCGT and OCGT new entrant generation. The effect is more consistent with the potential impacts from changes to capital costs, fuel costs and the exchange rate though.

The figures show that potential changes to key input parameters used in estimating new entrant LRMC should be considered, to ensure that energy purchase cost estimates are cost reflective longitudinally as well as at a point in time. Generators (existing and new) will be considering the potential impact of variability in these factors in their pricing decisions, and hence there is the prospect that this risk may pass through to the energy purchase cost for retailers.

14 Appendix C – NERA Economic Consulting report on an approach to estimating the retail margin and retail costs for a mass market new entrant

5 September 2006

Approach to Estimating the Retail Margin and Retail Costs for a Mass Market New Entrant

Integral Energy – Final Report

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1. Introduction

The Minister's Terms of Reference require IPART in making its investigation and report on the setting of tariffs for small retail customers for the period 2007-2010[1] to consider the appropriate 'mass market new entrant retail margin' and 'mass market new entrant retail costs.'

The focus on this report is on estimating the mass market new entrant retail margin. However, we note at the outset that there are no 'hard and fast' rules as to which costs should be explicitly included in the estimate of new entrant retail costs and which should be compensated for via the allowance made for the retail margin. As a result, this report considers the costs that would be faced by a mass market new entrant, and then proposes an allocation of some of those costs to the estimate of the retail margin and others to retail costs.

In addition to setting out a proposed approach to calculating the mass market new entrant retail margin, the final section of the report considers the appropriate approach to estimating mass market new entrant retail costs.

The remainder of this report is structured as follows:

- Section 2 discusses the general costs (including the costs of risk) which could potentially be compensated for by the allowed retail margin;
- Section 3 considers the additional costs that would be faced by a mass market new entrant;
- Section 4 assesses what has changed in the NSW policy and market environment since 2004, which may justify a change in the retail margin from that allowed by IPART in its previous determination;
- Section 5 provides a comparison of the retail margin allowed previously by IPART and those allowed in other jurisdictions;
- Section 6 sets out NERA's approach to calculating the reasonable range for the retail margin, based on a bottom-up assessment of the costs that are intended to be compensated for via the retail margin; and
- Section 7 outlines the appropriate approach to calculating the reasonable range for operating costs for a mass market new entrant.

1 IPART's Determination will apply from 1 July 2007 to 30 June 2010.

2. What Costs is the Retail Margin Intended to Cover?

As a general principle, the non-energy and non-network costs faced by retailers can either be directly reflected as a line item in the retail costs estimated for the business, or an allowance can be made to cover these costs in the retail margin. The retail margin should compensate retailers for costs not compensated for elsewhere in the framework (including the cost of systemic and asymmetric risks).

The approach to estimating the retail margin adopted both by IPART in its previous reviews of retail tariffs and by other regulators in Australia is largely one of 'benchmarking' against the margin decisions of other regulators, adjusting for specific factors present in the particular circumstances of each review. In undertaking such a benchmarking exercise, it is important to be clear on exactly what is covered by the retail margin decision made in other jurisdictions, in order to be able to determine the relevant comparability between the margins that have been allowed.

In addition, being clear on what costs are intended to be compensated via the retail margin means that it is possible, at least in the case of the major cost items, to undertake some quantification of the appropriate size of the retail margin, independent from a consideration of what has been allowed by other regulators.

There are no 'hard and fast' rules as to whether a particular cost should be allocated to the retail margin, retail costs or to energy costs. Regulators in Australia have differed in the approach they have adopted. For example, IPART included depreciation costs in its estimate of the appropriate retail costs in its 2004 determination.[2] In contrast, ESCOSA in its 2005 determination included depreciation as one of the costs to be covered by the allowed retail margin. Similarly, in Victoria risk management costs associated with energy purchases have been allowed for within the retail margin.[3] In South Australia these costs appear to have been wholly incorporated within the calculation of energy costs.

An important first step in determining the appropriate retail margin for a new entrant is therefore to consider, within the overall framework adopted for the retail review, which costs are intended to be compensated for via the margin and which are allowed for in other aspects of the determination (ie retail operating costs or energy costs). It is important that all relevant costs (including the cost of risk) are reflected in the overall cost benchmark derived for retail tariffs. Exactly where the compensation for each cost occurs is arguably of lesser importance.

The remainder of this section considers the potential costs (including the cost associated with relevant risks) which may be compensated for via the retail margin.

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2 IPART, 2004 Determination, p9.

3 CRA provided advice to the Victorian government on the appropriate level of the retail tariffs for Victorian distributors. CRA allowed for energy purchase risks as part of the estimate of wholesale electricity costs. However, they also allowed a further amount in the margin to compensate for 'remaining uncertainties' associated with energy purchase risk.

2.1. Potential Costs to be Covered by the Retail Margin

IPART's 2004 determination stated that its estimate of the retail margin was intended to compensate retailers for capital investments and the risks they assume (where those risks are not compensated for in other aspects of the regulated tariff), such as those associated with power trading, competition from substitutes and customer default: [4]

> *"The net profit margin represents the reward to investors for committing capital to a business. The level of profit margin is influenced by the level of risk associated with energy purchasing costs, customer default and bad debt, and competition from electricity substitutes."*

The general classes of costs which may be covered by the retail margin include:

1. Return on capital, including:
   – physical assets;
   – working capital; and
   – intangible assets (primarily the value of each retail customer)
2. Return of capital (depreciation)
3. Amortisation of intangible assets
4. Interest and taxes[5]
5. Compensation for asymmetric risks:
   – residual risk associated with energy purchases;
   – other asymmetric risks, eg the risk of billing systems failure
6. 'Headroom.'

The first four items could be included explicitly as line items in estimating retail costs. To the extent that they are not, it would be appropriate to make an allowance for them in estimating the retail margin. IPART's 2004 determination included an allowance for depreciation in operating costs rather than in the margin. The margin was intended to compensate the retail businesses for the return on physical assets (including interest and taxes). A return on working capital appears to have been excluded from the margin calculation.[6]

The retail margin is also intended to compensate the retailers for the risks they face. The 'risk' faced by a retailer requires compensation if one of the following applies:

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[4] IPART 2004, p42

[5] In general, compensation for interest and taxes will occur via the allowed return on capital. However, the compensation allowed in the margin for risks will also be subject to tax, and this should be recognised in setting the level of the overall margin.

[6] See discussion in section 5.2.4. It is not clear from IPART's determination whether an explicit return on working capital was instead allowed for within the estimate of retail costs.

1. the risk creates variability in profits such that profits are high when the stock market return in high and low when the stock market return is low (systemic risk);[7] and
2. the risk creates variability in profits that is not symmetric (asymmetric risk with downside greater than upside).

For example, retailers may face asymmetric risk associated with energy purchases, arising from very low probability but high value market outcomes at times when the retailer is not fully hedged. Hedging and risk management costs may be included in the estimate of energy purchase costs. However, to the extent that energy purchase risk is not fully addressed in the allowance made under energy purchase costs, an allowance should be included in the margin.

In addition, there may be other asymmetric risks, such as those associated with failures in billing systems (such as that which led to the demise of OneTel). Even though such events are small probability, the high costs if they do occur mean that the expected costs to investors of these events can be material. Investors need expected revenues to cover expected costs (including those associated with low probability catastrophic events) and this is true irrespective of the WACC that is earned on invested capital.[8] The costs of these risks should be compensated for via the retail margin, so that the expected revenues of the business equal expected costs.

In some jurisdictions 'headroom' has also been included in estimating the retail margin. This is intended to be an additional element built into tariffs to ensure that regulated retail tariffs provide sufficient scope for both the incumbent retailers and for other retailers (including new entrants) to offer attractive competitive tariffs to end-users. Where regulated tariffs are set at (or even potentially below) actual cost levels, there will be limited opportunity for other retailers to offer competitive tariffs, which can affect the development of the competitive market.

The Victorian Government's determinations for both electricity and gas retailers in Victoria for the period 2004-2007 explicitly included headroom in determining the allowed margin. IPART has not previously incorporated any 'headroom' in its estimate of the appropriate retail margin.

It is important to note that 'headroom' can be incorporated in a number of elements of the framework, not only the retail margin estimate. For example, establishing retail operating costs on the basis of a mass market new entrant (as required by the Minister's Terms of Reference) is likely to result in regulated tariffs being higher than they would be if set purely on cost reflective levels for the incumbent. Similarly, where retail cost estimates are established conservatively (whether for a new entrant or for the incumbent), this may itself provide headroom to allow for the development of more competitive tariffs by others.

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7 Note, that this risk requires compensation even if the upside is equal to the downside in monetary terms *because* investors hate losing an extra $1 when the market is down more than they love winning an extra $1 when the market is up The rationale is that investors have diminishing marginal utility of money such that when they are rich (market is up) they don't value extra income as much as when they are poor (the market is down);

8 That is, this compensation is required even if the WACC is zero or the business runs purely on operating costs (ie, even if there is no capital in the business to apply a WACC to).

The estimate of energy purchase costs can also impact the level of headroom. For example, in South Australia, ESCOSA estimated energy purchase costs on the basis of the costs of the incumbent, but noted that current contract prices had fallen such that a new entrant would be able to purchase energy at a lower cost than that allowed for in regulated retail tariffs. ESCOSA noted that this had the impact of providing a degree of headroom within retail tariffs.[9]

[9] ESCOSA, March 2005, Final Report, p80.

3. Additional Costs Incurred by a Mass Market New Entrant

As noted in the introduction, the Minister's Terms of Reference require IPART in making its investigation and report on the setting of tariffs for small retail customers for the 2007-2010 period to consider the appropriate 'mass market new entrant retail costs' and the 'mass market new entrant retail margin.'

The Terms of Reference reflects a significant departure from the approach that IPART was previously required to adopt, which was to estimate the retail costs and retail margin appropriate for a standard retailer.

IPART notes in its Issues Paper that an implication of this is that new entrant costs are likely to include additional costs, such as customer acquisition and billing systems, and may lead to a higher overall cost than was included in the 2004-7 determination. [10]

The following three categories of additional costs would be incurred by a new entrant:

1. The costs associated with customer acquisition (which equates to the implied valuation of Integral Energy's current customer base, ie, a valuation of intangible assets);
2. The costs associated with establishing the physical infrastructure necessary to operate a retail business (eg, billing systems, call centres). These costs are likely to be higher for a new entrant than for the existing incumbent retailer; and
3. Cost differences in retail costs which a new entrant would face compared to the incumbent business, given that the incumbents in NSW are government-owned and also own a distribution network business.

These three cost categories are discussed in turn below. Whether these costs should be compensated for via the retail margin or included within operating costs is discussed in section 3.4.

3.1. Customer Acquisition Costs

In order to reach an efficient scale a new entrant must invest in acquiring customers. This investment can take a number of different forms including: advertising; doorknocking, sponsorship or direct purchase of customer bases from incumbents. Once customers are acquired (ie, once the new entrant is an incumbent) a return on those investments is required. Moreover, the business will also require a return of (amortisation of) those investments over the typical life of a customer so acquired. With the exception of network and energy costs, customer acquisition costs are likely to be the most significant cost faced by retailers.

In order to estimate customer acquisition costs we have used a variety of sources across a number of relevant industries. The sources used include market transactions, stock market analyst reports and reported accounting information. The industries examined include retail energy and retail telecommunications.

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[10] IPART Issues Paper, p. 2.

3.1.1. Retail Energy

One of the most readily available estimates of customer acquisition costs are the actual amounts paid for the direct purchase of retail energy customer bases. The amount a new entrant is willing to pay for customers in such transactions will reflect the cost to them of acquiring those customers by other means. That is, retail company A will only buy customers from retail company B if the price is lower than company A's own assessment of the costs of acquiring the same number of customers by other means (eg, doorknocking).

Around the time of the introduction of full retail competition in Victoria, NSW and South Australia, a number of customer purchases were made. ESCOSA has summarized the price paid per retail customer for a number of relevant Australian transactions. ESCOSA's estimates are provided in Table 3.1.

Table 3.1
ESCOSA's Reported Australian Energy Retail Customer Acquisitions

Date	Market	Company Acquiring	Company Selling	Customer Relationships	Acquisition cost ($ per customer)*
July 2002	Vic	Origin	Citipower	264,000	578
June 2001	Vic	Origin	Powercor	582,000	601
June 2000	Vic	Pulse	United Energy	560,000	764
Jan 2000	SA	AGL	ETSA	734,000	293
Mean					**559**

Source: ESCOSA, September 2004 Inquiry Into Retail Electricity Price Path, Discussion Paper p. 59.
*Note: *Adjustment for inflation up to June 2006 using ABS CPI (catalogue reference 6401.0).*

On the basis of the above market transactions, customer acquisition costs in Australia for a new entrant (at current prices) are somewhere between $293 and $764 per customer (with an average of $559 per customer).

The customer purchase prices presented in Table 3.1 were calculated by ESCOSA as an approximate total purchase price paid divided by the number of customers acquired in the transaction. This somewhat simplified approach is susceptible to distortion since there may be tangible assets, debt and/or receivables also included as part of the same transaction. As a result, this approach is likely to understate the price per customer where the retailer being transferred contained significant debt liabilities or overstate it where other significant tangible assets and receivables are transferred in the transaction.

Review of the financial accounts of Origin and AGL reveals that these transactions did also involve the simultaneous transfer of various receivables, debt liabilities and tangible assets. Importantly, these accounts also reveal the fair value of intangible assets attributed to the customers acquired. These asset values are likely to provide a more accurate assessment of the per customer purchase price inherent in each transaction than those presented in Table 3.1. Table 3.2 provides the cost of reported customer acquisitions based on the fair value of intangible assets.

Table 3.2
Fair value of Australian customer acquisitions

Date	Company Acquiring	Company Selling	Customers	Value Of Intangible Assets $m	Price Per Customer $ of the day	Price Per Customer $ 2006*
Jan 2000	AGL [a]	ETSA	734,000	267.6	365	449
June 2001	Origin [b]	Powercor	582,000	243.1	418	482
July 2002	Origin [c]	Citipower	264,000	149.0	564	629
July 2002	AGL [d]	Pulse	1,079,000	881.9	817	911
				Mean	**541**	**618**
				Weighted average^	**580**	**661**

Source: [a] *AGL 2000 Annual Report*
[b] *Origin 2002 Annual Report*
[c] *Origin 2003 Annual Report*
[d] *AGL 2003 Annual Report*
Notes: * *Inflation adjusted using ABS CPI (catalogue reference 6401.0)*
^ *Using customer numbers as weights*

In addition to the above transactions, other recent and proposed customer purchases include:

- International Power's July 2005 purchase of a 50% interest in Energy Australia's Victorian and South Australian retail interests. This included acquiring a 50% share of Energy Australia's 175,000 customers in these markets. At a purchase price of $60 million, this implies a customer acquisition cost of $685 per customer ($706 in June 2006 dollars). (We have not included this in the above table because no fair value of the intangible assets was reported in the company accounts.)

- The proposed sale of Sun Retail by the Queensland Government which involves the sale of 1,200,000 retail electricity customers, 80,000 gas retail customers and 53,000 bottled LPG customers.[11] With the sale conservatively estimated to earn at least $1 billion,[12] this gives an average customer acquisition cost of $750.

It is worth noting that it appears that the price paid per customer acquisition has tended to rise over time. Given that the price paid for customers reflects the expected cost of acquiring

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11 Queensland Treasury, http://www.treasury.qld.gov.au/energysales/retail/index.shtml

12 Blake Dawson Waldron, *Resource and Energy Law Update*, July 2006

them by other means (eg, door knocking), this upward trend may reflect an improved understanding of these costs in the market since 2001, when the lowest prices per customer were paid.

These historic Australian customer acquisition costs are consistent with direct customer acquisition costs in foreign jurisdictions (both in terms of the average cost per customer and the spread).

Table 3.3 provides a summary of UK, New Zealand, Canada, US and Belgium direct purchase prices for customers. These prices have been adjusted for purchasing power parity and inflation. The eight UK electricity purchases have been sourced from the Office of Gas and Electricity Markets (OFGEM) while the remaining observations have been sourced from analyst reports and company annual reports.

Table 3.3
Foreign energy retail customer acquisitions

Date	**Market**	**Retailer customer acquired sold by**	**Acquisition cost (AUD $ per customer)***
Nov 1998 [a]	UK	Midlands Electricity	213
Jun 1999 [a]	UK	SWEB	460
Aug 2000 [a]	UK	Norweb	426
Aug 2000 [a]	UK	Swalec	525
Feb 2001 [a]	UK	Yorkshire	720
Aug 2001 [a]	UK	Northern	671
Aug 2001 [b]	New Zealand	NGC	264
Dec 2001 [b]	UK	Enron Direct	467
Apr 2002 [b]	US	AEP	187
May 2002 [b]	Canada	Enbridge	567
Jul 2002 [b] ^	US	NewPower	314
Jul 2002 [a]	UK	Seeboard	695
Dec 2002 [a]	UK	TXU	673
Jul 2005 [c]	Belgium	Oxxio	326
		Mean	**465**

Source: [a] *OFGEM, Domestic Competitive Market Review, April 2004*
[b] *Peace Software, Retail Energy Customer Valuation White Paper, 2003*
[c] *Centrica Annual Report 2005/06*
Notes: ** Adjusted using World Bank purchasing power parity conversion rates and adjusted for Australian CPI up to June 2006.*
^ Price bid prior to the NewPower bankruptcy

The price per customer paid in foreign jurisdictions was between $187 and $720 with an average of $465 per customer. These figures have been adjusted into Australian dollars using the World Bank purchasing Power Parity conversion rates[13] and adjusted for Australian inflation using the ABS eight capital cities Consumer Price Index.[14]

The above customer purchase costs are also consistent with estimates of organic customer acquisition costs (ie, acquiring customers through means other than purchase directly from incumbent retailers such as door knocking). A 2000 CeTurn Limited[15] study of the competitive UK electricity retail market found that it cost UK electricity retailers GBP 150 (AUD 399[16]) to acquire a customer through direct sales or direct mail. This figure is close to, but slightly below, the average foreign purchase price per customer in Table 3.3 ($465). It is moderately below the Australian average in Table 3.2 ($618) but well within the range of Australian transactions.

Similarly, the above customer acquisition costs are consistent with market analysts' valuations of retail customers. For example, UBS[17] estimate that an average retail electricity customer is worth GBP 231 (AUD 502[18]).

Energy retailing in Australia would appear to be a substantially similar industry to energy retailing in North America, the UK and New Zealand. We therefore see little reason to give the figures in Table 3.3 less weight than those in Table 3.2.

The average of all energy retail customer acquisition cost observations reported in the above tables is $524 per customer. We believe that this is the most reliable estimate of the cost of acquiring retail energy customers through direct purchase. This is consistent the mean value of acquisition cost observations across all industries ($540), lower than the mean value of Australian customer acquisitions ($618) and higher than the mean international energy acquisition cost value of ($465) and estimates of the cost of organic customer acquisitions (such as the CE Turn estimate of $399).

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13 World Bank, World Development Indicators, 2004.

14 ABS catalogue reference 6401.0

15 As referenced in Peace Software, Retail Energy Customer Valuation White Paper, 2003.

16 Adjusted for purchasing power parity and inflation.

17 UBS European Investment Research - European Emission Trading Scheme, September 2003, Page 65

18 Adjusted for purchasing power parity and inflation.

Table 3.4
Summary of acquisition costs

Acquisition cost measure	Mean acquisition cost (AUD $ per customer)
Australian energy retail [a]	618
All industries (Aust & International) [b]	540
All energy retail (Aust & International) [c]	524
Foreign energy retail [d]	465

Notes: [a] *Mean fair value of customer purchases as presented in* Table 3.2

[b] *Mean of observations presented in* Table 3.2, Table 3.3,*and* Table 3.5 *along with the mid-point of observed ranges in* Table 3.7 *and with the inclusion of the International Power/Energy Australia and the Pulse/United Energy transactions on a purchase price basis.*

[c] *Mean of observation in* Table 3.2 *and* Table 3.3 *along with the International Power/Energy Australia, and the Pulse/United Energy transactions on a purchase price basis (but excluding the Sun Energy newspaper valuation).*

[d] *As per* Table 3.3.

Conclusion 3.1

The best estimate of customer acquisition costs from energy market data only is $524 per customer.

3.1.2. Telco and other industry values

The underlying economics of retailing telephony and electricity are very similar. In both industries the underlying service is a relatively homogenous product[19] with retail value added being provided through improved customer interface and billing arrangements.

It is therefore unsurprising that reported customer acquisition costs for telephony are very similar to the values for energy retailing estimated in Table 3.2 and Table 3.3 above. Table 3.5 provides sample phone customer acquisition costs for Australia and the USA.

[19] Note that many telephony retailers have no network assets and simply resell services provided by, for example, Telstra.

Table 3.5
Sample telco customer acquisition costs

Firm	Market	Year	Customer acquisition cost (AUD $ per customer)[#]
Hutchison [a]	Aust (mobile)	2004/05	433
Hutchison [a]	Aust (mobile)	2005/06	402
Sprint [b]	USA (fixed line)	2001	509
Nextel [b]	USA (mobile)	2001	767
Voicestream [b]	USA (mobile)	2001	541
Alltel [b]	USA (mobile)	2001	492
Mean			**524**

Source: [a] The Standard, 'Hutch Australia unit lifts 3G number, narrows loss', 8 March 2006
[b] Siebel, H., 'Overview of Customer Acquisition Costs', 5 July 2002Peace Software, Retail Energy Customer Valuation White Paper, 2003

*Notes * Adjusted using World Bank purchasing power parity conversion rates and adjusted for Australian CPI up to June 2006.*

It is worth noting that the average revenue earned per mobile phone customer is substantially lower than the average revenue earned from electricity retail customers (see table below and note that average annual electricity retail revenue per Integral Energy customer is around $1,322).

Table 3.6
Mobile phone revenue per customer

Provider	2001-02 ($)	2002-03 ($)	2003-04 ($)	2004-05 ($)
Telstra	536.94	492.15	450.89	441.16
Optus	442.52	514.65	543.15	561.46
Vodafone	574.87	501.33	445.06	506.58
Other	956.52	679.31	720.83	655.56
Industry	523.84	504.84	482.87	491.12

Source: ACCC Telecommunications Market Indicator Report 2004-05

Lower mobile telephony bills mean that, as a percentage of the annual revenue, customer acquisition costs in mobile telephony are higher than in electricity retailing. However, this in no way invalidates the use of the absolute customer acquisition costs in mobile telephony as a proxy for the absolute customer acquisition costs in electricity retailing. In both industries the same strategies and investments are used to acquire customers (eg, advertising; doorknocking, sponsorship etc). We are unaware of any reason to believe that the cost of these activities are higher for mobile telephony than for electricity retailing.

It follows that retail customer acquisition costs in other industries with a relatively homogenous product (eg, mortgage origination, fixed line telephony, and pay TV) should also yield relevant information on customer acquisition costs in electricity retailing. It is therefore unsurprising that customer acquisition costs in these industries (Table 3.7) are similar to the estimates for energy retailing listed in Table 3.2 and Table 3.3.

Table 3.7
Sector customer acquisition cost comparison

Industry sector	Date	Customer acquisition cost range $ per customer*
Mortgage lending	Pre 2002	484 – 1130
Telco	2001	402 – 767
Pay TV	2001	193 – 863
Simple Average of Mid Point of Ranges		**$640**

Source: Siebel, H., 'Overview of Customer Acquisition Costs', 5 July 2002.
*Notes * Adjusted using World Bank purchasing power parity conversion rates and adjusted for Australian CPI up to June 2006.*

The simple midpoint average of $640 per customer is consistent with the previously cited estimates of customer acquisition costs.

Conclusion 3.2

Cross referencing the energy market data with that for other industries suggests that a customer acquisition cost of $524 per retail Australian electricity customer is consistent with equivalent costs in the telephony sector, and within the reported range for other similar retail industries.

3.2. Tangible Assets

The second category of additional costs that would be faced by a new entrant are the costs associated with establishing the necessary physical infrastructure to operate a mass market retail business in NSW. Such costs include the costs of billing and IT systems, and call centres.[20]

The cost of physical systems can be expected to form a much lower proportion of total costs for a retail business than the costs of the investment the business makes in customer acquisitions. However, a return on and of these tangible assets still needs to be incorporated within the overall estimate of the appropriate level of regulated retail tariff.

A conservative approach would be to base the new entrant cost on the historic costs of the incumbent. It is likely that a new entrant's costs would be above the level of historic costs, as a result of the following factors:

[20] IPART recognises in its Issues Paper that a new entrant would face these costs: IPART Issues Paper, p.2.

- Integral's historic book values provide no compensation for inflation - in reality a new entrant would have to buy these assets at today's prices and not the prices in existence when Integral purchased these assets;
- Integral's historic book values include no amounts to reflect the establishment costs a new entrant would face - such as feasibility studies, capital raising costs, staff recruitment and other costs associated with project managing entry into the market;
- Integral's historic retail book values involve an allocation of common costs between its retail and network business. A stand alone new entrant retailer would have to recover all these costs from its retailing operations;
- a new entrant would not also own the associated distribution network, resulting it in being likely to face additional B2B costs not currently incurred by Integral; and
- the billing systems a new entrant would need to put in place would most likely need to have the ability to issue time of use bills, in the light of COAG's agreement to roll out time-of-use meters. Integral's current billing system does not have this capability for all mass market customers.

Conclusion 3.3

Calculating the return on and of tangible assets on the basis of the historic costs of the incumbent represents a conservative approach, since new entrant costs are likely to be above these costs.

3.3. Differences in Retail Operating Costs

The final category of cost differences relate to differences in operating costs between a new entrant and the incumbent businesses, which are government owned and also directly own the associated distribution networks for their area.

As a result of its ownership of the network business, Integral can be expected to attract a higher credit rating than would a new entrant. As a result, although a new entrant would have to provide a similar level of bank guarantee to NEMMCO as does Integral, the costs of obtaining this guarantee are likely to be above the costs incurred by Integral.

In addition a new entrant (if it had less than a BBB credit rating) would need to provide a bank guarantee in order to be able to purchase network services from the relevant distributor. This is an additional cost that Integral Energy currently does not have to face, as a result of its common ownership of both a network and a retail business.

3.3.1. Estimate of Additional Financing Costs for a New Entrant

The additional operating costs a year estimated by Integral in relation to the above cost categories are:

- Additional financing costs for bank guarantee required by NEMMCO: Integral has a Treasury guarantee that costs it $75k per annum. An independent retailer would need the same size guarantee, but sourcing from a bank would cost $200-$400k per annum. **Implied additional cost: $125-$325k per annum**
- Cost of bank guarantee to be provided to Integral's network business: **$200-$400k per annum additional cost**

Conclusion 3.4

New entrant costs will be above those for the incumbent as a result of the incumbent's ownership of the associated network business.

3.4. Where Should the Additional Costs be Reflected?

The additional costs that would be faced by a new entrant could potentially be captured either in the retail cost estimate or in the retail margin.

IPART in its Issues Paper has characterised the additional costs faced by a new entrant as increasing the *retail operating cost* estimate. However, at least some of the additional costs that would be likely to be incurred by a mass market new entrant could alternatively be reflected in an increased retail margin, rather than incorporating the costs directly as line items in retail costs. In particular, the return on and of the investment associated with customer acquisitions may be more appropriately captured in the margin analysis.[21]

Whether to incorporate these additional costs directly within the retail cost estimate or within the retail margin is an issue which will need to be addressed by IPART in deciding on the appropriate analytical framework for the review. In section 5.3 of this report we present a proposed allocation of these costs between the retail margin and retail costs.

We note that if IPART decides to incorporate the additional costs faced by a new entrant within retail costs, the implication is that the additional new entrant cost estimates presented in this section of the report would need to be explicitly incorporated as line items in the estimate of retail costs, whilst the estimated margin would fall.

[21] This would be in line with the approach adopted by ESCOSA: see discussion in section 5.

4. Changes in NSW since IPART's 2004 Determination

There have been a number of changes in the policy and market environment since 2004 that imply that the margin appropriate for 2007-2010 will be above the 2% margin determined by IPART in its last determination.

The first change is that the Terms of Reference require IPART to determine the appropriate margin for a 'mass market new entrant'. The margin can be expected to be higher for a new entrant than for the incumbent retailer as a result of two factors:

- The need to explicitly value the customers of the retail business, and to allow for a return on and amortisation of this value in the margin;[22] and
- The appropriate return on tangible assets (eg, billing systems, B2B costs) included in the margin should be based on the costs incurred by a new entrant, rather than on the historic cost of the incumbent's physical assets.

IPART's previous determination of a 2% retail margin included no return on customer acquisition costs. While this may have been justified when setting efficient costs for an incumbent retailer that has a legislatively inherited customer base, it is not appropriate when estimating costs for a new entrant (as is required by the Minister's Terms of Reference). Indeed, IPART recognizes in its Issues Paper the need to include customer acquisition costs in making its determination for the 2007-2010 period.

The second important change in the market and policy environment is the NSW government's decision to phase out the ETEF scheme, which will result in increased energy purchase risk for NSW retailers. In 2004, IPART considered energy purchase risk to form part of the margin, but concluded that its value was zero as a result of ETEF. A new entrant will not have hedging through ETEF available and, hence, will inevitably be exposed to a greater level of risk. If hedging costs are included as part of the estimated energy costs, there is still a residual energy risk which should be reflected in the margin.

It is also worth noting that the current allowed margin of 2% in NSW is significantly below the margins that have been allowed in other jurisdictions (notably 5% in SA and 7-9% in Victoria). The allowance for operating costs is also below that which has been allowed in other jurisdictions.[23] Differences in coverage and market circumstances at the time of the determinations may be able to at least partially explain these differences. However, OFGEM identifies that:

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22 The alternative would be to allow for the return on and amortisation of the value of customers as part of retail costs.

23 Retail operating costs were set at $70 per customer in NSW, compared to $85 in the ACT and Victoria. ICRC, 2006, Draft Decision, *Retail Prices for Non-contestable Electricity Customers*, p30. Retail operating costs in SA were set at approximately $84 per customer in December 2004, with a CPI plus two percent increase thereafter. ESCOSA, March 2005, *Inquiry into Retail Electricity Price Path, Final Report*, p53.

> *The prices paid in mergers provide a useful basis to assess profitability in the gas and electricity supply sector since they will take some account of the profit expectations of the acquiring business.*[24]

In this regard it is telling that there have been no customer purchases of NSW electricity retail customers. This would support the view that the current regulated retail prices are so low as to provide a disincentive to potential market entrants.

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[24] OFGEM, Domestic Competitive Market Review 2004, April 2004.

5. Comparison with Margin Decisions in Other Jurisdictions

This section considers the recent retail margin decisions in NSW, Victoria and South Australia, for both the electricity and gas retail sectors. These represent the three most recent regulatory decisions on the retail margin.[25]

We have focused in particular on the coverage of the retail margin in each of the decisions, paying particular regard to the costs and risks that are intended to be covered by those margins in each case and the comparability with the costs and risks faced by a mass market new entrant in Integral's area.

The main point emerging from our analysis is that there has been little commonality with regard to the assumed coverage of the margin in each jurisdiction. Margins in other jurisdictions include some costs which have instead been included in operating costs in NSW (eg, depreciation). They also include some factors not taken into account anywhere in regulated retail tariffs in NSW (eg, intangible assets in South Australia; 'headroom' in Victoria). In many cases, the question of whether certain factors have been incorporated in the assumed margin is at best opaque, and has become more so over time.

In all three jurisdictions, retail margins have been established by having regard to the margins allowed by other regulators. However in ESCOSA's recent decision this analysis was supplemented by a calculation of the required return on and of investment.

Given the differences in coverage of the retail margin between jurisdictions, and the lack of clarity as to which costs have been considered in setting the margin, this suggests that there would be considerable merit in adopting an alternative approach to determining the retail margin, other than 'by comparison.' In section 6 of this report we set out our proposed approach to calculating the retail margin for NSW, by way of a 'bottom-up' quantification of the costs which are intended to be compensated via the margin. We note that the proposed approach is similar to that adopted by ESCOSA in its 2005 determination.

5.1. Comparison of Coverage of Retail Margin Across Jurisdictions

The following table presents a comparison of the coverage of the allowed retail margins for electricity and gas in NSW, South Australia and Victoria. In particular it summarises the inclusion or exclusion of each of the classes of costs which may be covered by the retail margin (as listed in section 2.1 above). A tick indicates that the element is included in the margin; a cross indicates that it is not included. Where a cell has been left blank this is because it is not clear from the relevant determination whether or not the factor has been included in the retail margin.

[25] The ICRC considered the issue of the retail margin as part of its April 2006 report into retail prices for non-contestable electricity customers. The ICRC has recommended that the regulated tariff be discontinued from 1 July 2007. Its consideration of an appropriate retail margin to include within regulated tariffs before this date relied on a comparison of the allowed $/customer margins allowed in NSW and Victoria.

Table 5.1: Comparison of Coverage of Retail Margins Between Jurisdictions

	Electricity			Gas		
	IPART 2004/05 – 2006/07	**ESCOSA** 2005/06 – 2007/08	**Vic** 2004 – 2007	**IPART** 2004/05 – 2006/07	**ESCOSA** 2005/06 – 2007/08	**Vic** 2004 – 2007
Margin	**1.5-2.5%**	**4-6.5%**	**5-8%+ (CRA)** **7-9% (Govt)**	**2-3% (NERA)**	**3.4-4.3%**	**2-3%+ (CRA)**
Return on capital (physical assets)	✓	✓	✓	✓	✓	✓
Depreciation	✗ (included in operating costs)	✓			✓	
Return on capital (intangible assets)		✓			✓	
Amortisation		✓			✓	
Return on capital (working capital)	✗ (not clear if included in operating costs)	✓	✓		✓	✓
Interest and taxes		✓			✓	
Energy purchase risk	✗[1]	✗[2] (included in energy costs)	✓[3]	✗	✗	
Uncertainty of operating cost estimates			✓			✓
Riskiness of customer base	✓	?[4]				
Competition from energy substitutes	✓					
Headroom	✗	✗	✓	✗	✗	✓

1 IPART saw energy purchase risk as part of the margin, but gave no additional return for it, due to the ETEF.
2 ESCOSA 2005 determination contains no explicit discussion of energy risk in the margin analysis, although its earlier 2002 determination did reference the peakiness of the SA market as contributing to the choice of the margin estimate
3 CRA: energy purchase risk is included in energy costs, but allowance also made in the margin for remaining uncertainties.
4 ESCOSA 2005 determination contains no explicit discussion of cost of risk associated with customer default; 2002 determination did reference the risks faced by AGL as the retailer of last resort.

5.1.1. NSW: 2004/05 – 2006/07

The net profit margin for regulated retail electricity tariffs for the regulatory period July 2004 to June 2007 was set at 2% in IPART's 2004 determination.[26] This value was selected from a range of 1.5% to 2.5%.[27]

In the gas industry, instead of setting a regulated tariff, IPART has agreed Voluntary Transitional Pricing Arrangements with each of the standard gas suppliers to apply from 2004 to 30 June 2007.[28] The Voluntary Transitional Pricing Arrangements do not provide for an explicit retail profit margin. However, IPART's determination was informed by a NERA report, which had recommended a margin of 2-3% of total cost.[29]

5.1.2. Victoria: 2004 – 2007

In Victoria, the Government reached an agreement with privately owned energy retailers on a retail pricing structure to apply from 2004 to the end of 2007. This agreement reportedly incorporates margins of seven to nine percent of total sales.[30] Prior to reaching agreement, the Government engaged consultants CRA Asia Pacific to review the costs of supplying standard domestic and small business customers for Victorian gas and electricity retailers, in order to inform the Government's response to the retailers' pricing proposals for 2004.

For electricity retailers, CRA advised that the retail margin should be set at 5-8% of total revenue, plus an additional allowance for the uncertainty of cost estimates. For gas retailers, CRA's view was that the retail margin should be set at 2-3% of total revenue, plus an additional allowance for the uncertainty of cost estimates and also to provide headroom for competition to develop. The margin set in the subsequent government agreement with the retailers in unknown.

5.1.3. South Australia: 2005/06 – 2007/08

In 2005, ESCOSA set both the electricity and gas retail margins at ten percent of the sum of wholesale energy costs plus retail operating costs.[31]

The margins determined by ESCOSA are expressed on a different basis to those in NSW and Victoria, where margins are reported as a percentage of *revenue* and thus include network costs. ESCOSA notes that its electricity retail margin is broadly equivalent to five percent of total costs, given that network charges represent around fifty percent of AGL (SA)'s total

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26 IPART, 2004 Determination, p42.

27 IPART, 2004 Determination, p43.

28 The VTPAs allow retailer to increase default tariffs on average by up to the change in CPI each year (CPI+5% for the Murray Valley district).

29 NERA, 2004, *New South Wales Energy Retail Costs, A Report to IPART*, p 3.

30 These figures are sourced from an ESCOSA determination: ESCOSA, March 2005, *Inquiry into Retail Electricity Price Path, Final Report*, p57.

31 ESCOSA, March 2005, *Inquiry into Retail Electricity Price Path, Final Report*, p57.

costs.[32] The gas retail margin is equivalent to approximately four percent of total sales revenue.

In both cases, ESCOSA carried out a return on investment analysis, to provide comfort that its benchmark-derived margin was appropriate. This analysis produced range of 4% to 6.5% for electricity, and a range of 3.4-4.3%, expressed as a percentage of revenues.[33]

5.2. Elements of the Margin

The treatment in the previous regulatory decisions of the various cost elements that could potentially be covered by the retail margin is discussed in more detail below. In some cases, whether or not certain costs have been included in the margin is not clear.

5.2.1. Return on capital (tangible assets)

IPART's view as expressed in its 2004 determination is that the retail margin "represents the reward to investors for committing capital to a business."[34] The margin allowed by IPART therefore was intended to provide a return on the capital invested in the physical assets required to operate a standard retail electricity business.

Similarly, a return on capital is included in the margin in Victoria, and in South Australia. ESCOSA also carried out a return on investment analysis, applying a WACC of 8% - 10% to capital assets (including physical assets), to compare with its benchmark margin analysis.

5.2.2. Depreciation

In its 2004 determination, IPART allowed for depreciation of retail assets in the calculation of operating costs,[35] rather than in the retail margin.

Depreciation is intended to be compensated for via the margin in South Australia. ESCOSA also made an explicit allowance for depreciation as part of its quantitative return on investment calculation. The report by CRA prepared for the Victorian government does not make specific reference to depreciation. As a result, we are not able to determine whether depreciation is included in the calculation of the margin in Victoria, or within operating costs.

5.2.3. Return on capital and amortisation (intangible assets)

For a retail business, its intangible assets (ie, customers) are of much greater significant than its physical assets.

IPART does not appear to have made any explicit allowance in the margin for a return on intangible assets or amortisation of those assets in its 2004 determination. In its earlier 2000

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32 ESCOSA, March 2005, Final Report, p57.

33 The range for electricity was expressed by ESCOSA as 8.0-13% of the costs of wholesale energy costs plus retail operating costs; the range for gas was 8.4% to 10.7%.

34 IPART 2004, p42

35 IPART, 2004 Determination, p9.

determination, IPART considered marketing costs, and decided that it was inappropriate to include these in the tariff for a regulated service, as marketing was not relevant for such a service.[36]

The exclusion of a return on intangible assets may be justified when setting efficient costs for an incumbent retailer that has a legislatively inherited customer base. However, IPART is now required by the Minister's Terms of Reference to estimate the costs for a new entrant. As discussed in section 3.1 and in IPART's Issues Paper, IPART will be required to consider customer acquisition costs in setting regulated retail tariffs for the 2007-2010 period.

In Victoria, a return on intangible assets and amortisation does not appear to have been allowed for in the margin. However, intangibles may have been taken into account to some extent in retail operating costs. In 2001 the ORG decided to "to amortise FRC costs over a 5-year period with a 10 per cent capital return"[37] in operating costs. FRC costs included marketing and advertising costs.

In contrast, ESCOSA's 2005 determination made specific allowance for a return on intangible assets and amortisation. ESCOSA estimated the appropriate size of this return quantitatively (as a check against its benchmark-derived margin estimate) using a value range of $138 to $167 million, and a pre-tax real WACC of 8% to 10%. The customer acquisition costs adopted by ESCOSA related to those implied by the price paid by AGL for ETSA Utility's customers in January 2000 ($238 per customer (2000 prices)). ESCOSA appears to have amortised these costs over a 20 year period.[38]

5.2.4. Return on capital (working capital)

It is not entirely clear from the 2004 IPART determination whether or not working capital was included in the 2% retail margin.

Working capital was considered, briefly, by IPART's consultant (NERA) in 2004, in its preparation of an estimated range for retail operating costs and the retail margin for IPART. In 2004, NERA considered the past treatment of working capital (previous IPART reports had not specifically set out the treatment of working capital), and made the assumption that working capital was included in the margin.[39]

This assumption appears to have been incorrect, since, in its 2004 determination, IPART observes that "Integral Energy and EnergyAustralia argued for the inclusion of working capital in the retail margin, which the Tribunal has previously decided should not be included." Working capital is not mentioned again in the determination. We infer, however, from the previous quote and from the fact that IPART did not increase its margin from the pre-existing retail margin of 1.5 to 2.5 per cent, that working capital is *not* included in the current retail margin in NSW.

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36 IPART, Dec 2000, Regulated retail prices for electricity to 2004, p51.

37 ORG, 2001, *Special Investigation: Electricity Retailers' Proposed Price Increases – Final Report*, p26

38 NERA calculation, based on 'backing out' the assumed customer life from amortisation of $4.5m on an intangible asset base of $170m and a WACC of 8%.

39 NERA, 2004, p24

However, given that IPART's consultant had assumed, in preparation of an estimated range for retail operating costs, that working capital *was* included in the margin, we can infer that working capital was *not* included in NERA's 2004 estimate of retail operating costs either. That is, it would appear that no allowance has been made for working capital in regulated retail tariffs in NSW.

A return on working capital is included in the margin in both South Australia and Victoria.

5.2.5. Interest and taxes

Interest and taxes are explicitly allowed for as part of the margin in South Australia. They are not explicitly provided for in NSW or Victoria, however, we assume these components are also included in the margin in these jurisdictions as part of the return on capital.

5.2.6. Energy purchase risk

In its 2004 determination, IPART saw energy purchase risk as part of the margin.[40] However IPART took the view at the time that most energy purchase price risk which would otherwise have been faced by NSW retailers was eliminated by the ETEF. Consequently, there was no need to provide compensation for this risk in the retail margin,[41] since it was "not appropriate to provide an allowance to standard retailers for costs that they will not incur over the course of the determination."[42]

In Victoria, compensation for energy purchase price risk was provided for primarily in calculating the wholesale electricity price. CRA based its calculation of energy costs on the cost of cap and swap contracts under a range of forecast scenarios, and additional risk costs. Additional costs due to hedge mismatches (under and over contracting) and premiums for additional demand risks were estimated and added to the wholesale energy cost benchmark calculated under CRA's methodology.[43] However, CRA stated that, where appropriate, allowance should also be made in retail margin for remaining uncertainties.[44]

In ESCOSA's 2005 determination for South Australia, compensation for energy purchase price risk appears to have been provided for in calculating the wholesale electricity price, and not in the allowed margin. This was done through incorporation of AGL SA's actual contract costs for swap and cap contracts (ie, including hedging costs). Where AGL was not covered by forward contracts (in the later part of the period), a modelling approach was used. This approach "identifies the optimal contracting strategy to minimise the financial impact on the retailer of variations in load and market outcomes from its contracting assumptions."[45]

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40 IPART, 2004 Determination, p42

41 IPART, 2004 Determination, p43.

42 IPART, 2004 Determination, p43.

43 CRA, 2003, *Electricity and Gas Standing Offers and Deemed Contracts (2004-2007)*, p19.

44 CRA, 2003, *Electricity and Gas Standing Offers and Deemed Contracts (2004-2007)*, p9.

45 ESCOSA, March 2005, *Inquiry into Retail Electricity Price Path, Final Report*, p43.

However, in making its 2002 determination, ESCOSA observed that the 5% margin allowed at that time was at the upper end of ranges used interstate, but was not unreasonable given the particular risks of operating in the peaky South Australian market (including the risk that generators can exercise significant market power in the South Australian market). [46] It would therefore appear that energy purchase risk was previously considered to be covered by the margin allowance in South Australia. To the extent that the 2005 ESCOSA decision on the margin was in part based on an assessment of the continuing applicability of its earlier determination, it could be argued that the margin in South Australia does account for energy purchase risk. However, the uncertainty regarding what exactly is intended to be covered by the margin in this regard also highlights the dangers with the 'regulatory comparison' approach to determining the margin, in that it becomes easy for cost factors to be overlooked or assumed included by default.

5.2.7. Risk of customer default

In its 2004 determination, IPART took the view that an allowance for the risk of customer default should be compensated for via the retail margin. IPART noted that there had been only limited switching in 2004, and considered that the 1.5% to 2.5% range for the retail profit margin provided sufficient compensation to retail suppliers for this risk.[47] However, IPART observed that "[a]s full retail competition (FRC) progresses, it seems reasonable to expect that the regulated customer base would become more 'risky'."[48] IPART expected the riskiness of the default customer base to increase over the 2004-2007 period.

There does not appear to have been an explicit recognition in the margin assessment of the costs implied by the risk of customer default in Victoria or SA.

In Victoria, CRA commented that "[the] net margin is intended to provide an appropriate return for the capital that is invested in the retail business, including [..] provision for bad debts."

In South Australia, ESCOSA has included bad debts within operating costs. However, the costs of risk arising from customer default were not explicitly discussed in setting the margin in ESCOSA's 2005 determination. However, ESCOSA observed in its 2002 determination that in South Australia, AGL was exposed to the risk of being the only first tier retailer with a legal obligation to supply all consumers who seek supply, and this factor was taken into account in ESCOSA's 2002 determination of the appropriate margin of 5%.

5.2.8. Uncertainty of cost estimates

In Victoria, CRA made an additional allowance in the retail margin for the increased uncertainty of operating cost estimates over the 2005 to 2007 period (as opposed to estimates for a single year, 2004). Further, the benchmark range established for retail operating costs in

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[46] ESCOSA, 2002, *Inquiry into Electricity Standing Contract Prices: Final Report and Determination*, p34

[47] IPART, 2004 determination, p44.

[48] IPART, 2004 determination, p44.

Victoria appears conservative, especially compared to the approach adopted in NSW in 2004.[49]

Such an allowance was not explicitly provided for in NSW or South Australia.

5.2.9. Competition from energy substitutes

In 2004, IPART considered that the margin would include an allowance for "competition from energy substitutes".

Such an allowance was not explicitly provided for in Victoria or South Australia.

5.2.10. Headroom

In its 2004 determination, IPART considered the inclusion of an additional allowance in the margin for the purposes of promoting competition ('headroom'). It took the view, however, that it was not desirable from an economic efficiency or equity perspective to allow 'headroom' in the retail margin; rather, tariffs were to reflect efficient costs. [50]

This stance was also reflected in the approach taken to setting a range for recoverable operating cost; that is, there was no explicit allowance for 'headroom' in operating costs (or in the wholesale energy cost estimate). While there was no explicit efficiency adjustment made to actual costs in the 2004 determination, in calculating the range, 'outlying retailers', which had costs significantly above most other retailers, were excluded. This had the effect of reducing the allowance for retail operating costs (ie, the reverse impact to that which would arise from an allowance for headroom).

The approach in Victoria appears to have been the opposite. CRA recommended that an allowance for headroom be made in the retail margin. However, in addition, CRA also estimated the allowance for retail operating costs on a conservative basis. That is, the allowance was increased from \$65 to \$90 in 2003, on the basis that there was uncertainty over the correct level, and \$90 was closer to the retailers' own assessment of operating costs.

In South Australia, there was no specific allowance for headroom in ESCOSA's margin determination for the purpose of promoting competition. This was in line with the Terms of Reference for the Inquiry, as specified by the Minister for Energy, which instructed that no allowance should be made for headroom. [51] However, in the event there *is* some headroom built into standing contract prices. This has apparently occurred fortuitously, through unpredicted movement in wholesale electricity prices which have resulted in new entrants facing energy contract costs below the level reflected in the regulated tariffs. [52]

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[49] In particular, the operating cost allowance in Victoria was increased from \$65 per customer to \$90 per customer in 2003, on the basis that there was uncertainty over the correct level, and \$90 per customer was closer to the retailers' own assessment of operating costs. In contrast, the 2004 IPART determination resulted in an allowance of \$70, chosen from an operating cost range of \$50-80 per customer, which was derived by explicitly excluding higher cost 'outliers.'

[50] IPART, 2004 determination, p24.

[51] ESCOSA, March 2005, *Inquiry into Retail Electricity Price Path, Final Report*, p77.

[52] ESCOSA, March 2005*Inquiry into Retail Electricity Price Path, Final Report*, p80.

> *'Even without a specific allowance for headroom … there should be sufficient margin to encourage ongoing competition between retailers and an ability to offer prices below the standing contract price.'*

5.3. Implications for the Retail Margin for NSW for 2007-2010

Table 5.2 below highlights those factors that NERA considers should be covered within the retail margin estimated for the NSW incumbent retail businesses for the 2007-2010 period, and compares this with the factors that were covered by the 2004 determination.

The proposed allocation is largely based on providing a greater degree of comparability and uniformity with the approaches in other jurisdictions, and on the similar treatment of the return on and of capital between physical and intangible assets.

Consistent with the discussion in section 3.4 of this report, we stress that the allocation of costs to the retail margin set out below is one possible allocation only. To the extent that IPART determines not to include all of the proposed factors in the retail margin estimate, then these costs should be adequately recognised in other aspects of the framework (ie, operating cost estimate and energy cost estimate).

Items shaded are those which imply that the margin for 2007-2010 should be *above* that for 2004, based on an assessment of both the factors that have changed since IPART's previous determination and also those cost elements which were not previously covered by the estimated margin. Darker shading indicates factors which we consider *could* be included in the margin (or alternatively, could be allowed for in establishing retail operating costs).

Table 5.2: Costs to be Compensated for via the Retail Margin 2007-2010

	IPART 2004/05 – 2006/07	**Proposal** 2007-2010
Return on capital (tangible assets)	✓	✓ New entrant systems costs above Integral's historic costs
Depreciation	✗	✓ Include within margin rather than operating costs
Return on capital (intangible assets)		✓ Customer acquisition costs
Amortisation		✓ Customer acquisition costs
Return on capital (working capital)	✗	✓ Include within margin rather than operating costs May have been omitted last time
Interest, Taxes	✓	✓
Energy purchase risk	✗	✓ Phasing out of ETEF. Hedging costs captured in energy cost estimates – but residual risk compensated by margin
Uncertainty of cost estimates	✗	?
Riskiness of default customer base	✓	✓
Competition from energy substitutes	✓	✓
Headroom	✗	?

5.3.1. Proposed costs to be recovered via the margin

We propose the following allocation of costs to the retail margin:

- **A return on tangible assets**, in line with IPART's approach in the 2004 determination. However, in contrast to the 2004 determination, the Terms of Reference for the current review establishes the appropriate benchmark for these assets is the systems that would be required by a mass market new entrant rather than Integral's existing asset base. This estimate includes an allowance for **interest and taxes**.

- **Depreciation** of tangible assets, since this provides both greater comparability with the decisions in other jurisdictions, and greater consistency with the treatment of intangible assets. We note that this is a re-allocation of these costs compared with the IPART 2004 determination which included them in operating costs.

- A return on **customer acquisition costs**, and amortisation of those costs, since IPART is now required under the TOR to establish a 'mass market new entrant retail margin' and 'mass market new entrant retail operating costs'.

- A return on **working capital.** This is a departure from IPART's approach in 2004, where working capital was excluded from the margin, but may not have been adequately captured in operating costs.
- Asymmetric risks:
  - Risks associated with **energy purchases**, to the extent that these are not covered by the estimate of energy purchase costs. As a result of the phase-out of the ETEF over the course of the next regulatory period, energy purchase risk must be taken into account in the current determination (as indicated in the Terms of Reference for the current review). If the estimated wholesale energy cost includes an allowance for hedging costs, then the bulk of energy purchase risk will be accounted for; however, unless the estimated wholesale energy cost is based on a fully hedged position, a residual energy risk would remain.
  - Compensation for **other asymmetric risks** to which a new entrant would be exposed (eg, the risk of not reaching efficient scale in a sufficiently short time or the risk of billing systems problems (such as caused the demise of OneTel)).

In the case of the **uncertainty of operating costs** and **headroom**, we consider that arguments could be made for the margin to also allow for these factors. If these factors are not to be allowed for in establishing the margin, then they should be allowed for in the approach taken to establishing operating costs.

5.3.2. Comparison with ESCOSA 2005 determination

Some but not all of the factors highlighted in the table and discussed above are taken into account in the 2005 ESCOSA determination. This implies that the margin determined for NSW should be *above* that determined by ESCOSA, *even if no explicit allowance for headroom is made in the margin.* That is, the retail margin for a mass market new entrant should be above 4%-6.5%.

The following points are of particular relevance in relation to the proposed coverage of the retail margin for NSW, compared to that adopted in South Australia:

- The margin allowed by ESCOSA explicitly includes the return on and of the value of intangible assets (predominantly customers). IPART will need to incorporate customer acquisition costs as part of its determination, since these would be incurred by a mass market new entrant. If these costs are incorporated in the margin (rather than being considered as a line item in retail costs) then the margin needs to rise, and the coverage will be more similar to that determined by ESCOSA.
- The per customer value used by ESCOSA is at the bottom end of the likely range of customer acquisition costs, whilst the assumed customer life is at the higher end of the likely range. Adopting more mid-range assumptions for these variables as being appropriate for a mass market new entrant in NSW would imply a higher cost in relation to intangible assets, which would increase the estimated margin.
- There is no headroom allowed in the ESCOSA margin. If IPART continues to believe that there should be no explicit headroom allowed in NSW (over an above that implied by the use of a mass market new entrant as the relevant benchmark for establishing retail

costs and the retail margin) then the coverage of the margins are again similar between states.

- There appears to be no allowance for residual energy purchase risk in the ESCOSA margin (all energy risks are incorporated in the energy cost estimate).[53] If this risk is not completely covered by the energy cost estimate established for NSW then there needs to be an allowance made in the retail margin (as per the approach in Victoria).
- It is not clear whether the margin allowed by ESCOSA provides compensation for other asymmetric risks. Including compensation for these risks within the margin estimated for NSW would increase the estimated margin compared to that allowed by ESCOSA

Conclusion 5.1

The margin determined for NSW should be above that determined by ESCOSA, ie the retail margin for a mass market new entrant should be above 4%-6.5%.

The comparative analysis of different regulatory decisions presented in this chapter also highlights the difficulties of this approach to determining an appropriate margin. The decisions of previous regulators have differed in terms of the costs which are intended to be covered by the margin, and the regulatory determinations themselves are not always clear on the exact coverage and in places are open to various interpretations.

As a result, it would be appropriate for IPART to attempt some form of quantification of the retail margin, rather than relying predominantly, or solely, on a comparison of regulatory determinations. This would be consistent with the developing regulatory approach in this area, and in particular with the approach adopted by ESCOSA in its 2005 determination.

In the following section we outline a proposed approach to undertaking such quantification. Such quantification can be used to inform the decision as to how far above the ESCOSA margin it would be reasonable to set the margin range for NSW.

[53] ESCOSA's 2005 determination contains no explicit discussion of energy risk in the margin analysis, although its earlier 2002 determination did reference the peakiness of the SA market as contributing to the choice of the margin estimate.

6. Estimation of the Appropriate Retail Margin

For the purpose of this report it is assumed that the retail margin should recover costs in relation to:

- A return on and of customer acquisition costs;
- A return on and of tangible assets excluding working capital;
- A return on working capital; and
- Compensation for asymmetric risks.

As noted previously, these are all costs that a new entrant retailer would incur and would require compensation for. If they are not recovered in the retail margin they will need to be recovered as line items in operating costs.

6.1. Contribution of customer acquisition costs to retail margin

In order to estimate the contribution of customer acquisition costs to the retail margin it is necessary to specify the required return on these investments and the appropriate rate of amortisation of these investments (for a new entrant). For the purpose of this report we adopt a real pre tax WACC of 8% as the required return on acquisition costs, consistent with the lower end of the 8% to 10% range adopted by ESCOSA in September 2004. This is also well below the lower end of the 11% to 16% range used by Ofgem in April 2004.[54]

The appropriate rate of amortisation of customer acquisition costs depends on the average life of a customer so acquired. A ruling by the Australian Accounting Standards Board (AASB) has specified that customer acquisition costs should be capitalised and amortised over the life of the customer contract for which they were incurred.[55] However, from an economic perspective it is more appropriate to amortise these costs over the *expected life* of the customer (to the extent that there is a material probability that the customer will stay with the retailer after the end of their initial contract).

For the purpose of this report we adopt an assumed average life per customer of 10 years for a new entrant. This is consistent with switching data available from the Victorian retail market where the ESC's *Victorian Energy Retail Comparison* report states that 22% of customers switched electricity retailer in 2004/05 (ie, one in five customers changed retailers). We consider Victoria to be a relevant example of a market where retail competition is firmly established. If all customers have similar switching patterns then this suggests that the average life of a customer acquired by any means will be five years. However, it may be that some customers will switch suppliers more often than once every five years and some less often. It is likely that the average life of an organically acquired customer will be less than 5 years as they will, by definition, be customers who are relatively more 'footloose' (ie,

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[54] Ofgem, Domestic Competitive Market Review 2004, para 5.27.

[55] See AASB *Subscriber acquisition costs in the telecommunication industry*, Urgent issues group – Interpretation 1042, December 2004.

customers who are attracted to switch, by definition, will have a greater propensity to switch). On the other hand, if a new entrant purchased an existing customer base then the average life of customers obtained in this manner could be expected to be longer. For the sake of conservatism, we have assumed that the average customer life for a new entrant will be 10 years - which is double that suggested by the Victorian switching data.

In section 3.1 we concluded that the best estimate of customer acquisition costs from energy market data is $524 per customer. Amortising $524 over 10 years at a WACC of 8% results in an annual return of $78. That is, in order to recoup an investment of $524 dollars over 10 years (including the time value of money at 8%) a new entrant will require annual payments of $78 for each of the 10 years. This represents around 5.9% of the average annual electricity bill for Integral's customer base[56] of around $1,322.[57] (Even if we assume a 20 year life for retail customers the contribution to the retail margin will still be around 4.0%.)

Conclusion 6.1

Our best estimate is that customer acquisition costs alone account for a retail margin of around 5.9%.

6.2. Contribution of working capital to retail margin

Electricity retailers generally recover their revenues between at least 1 and 3 months in arrears reflecting the fact that customers are on either monthly or quarterly billing cycles. In general, retailers' costs are paid on much shorter terms than this (eg, energy and network costs).

This means retailers must finance substantial working capital. Consequently, it is appropriate to provide a working capital allowance to cover this (as per IPART's most recent network decision).

A new entrant that had the same billing cycle as Integral for mass market customers (90 days) and average time from bill issue to payment (26 days) would have an average outstanding loan to customers of 71 days worth of service. Its payment terms with NEMMCO and other suppliers are likely to be materially shorter than this. We understand that NEMMCO has a weekly billing cycle and 28 day payment terms - giving an average time to payment of around 32.5 days. The other major cost is NOUS which we understand, based on Integral Network's billing practice, has a 90 day billing cycle and a 14 day payment terms (giving an average 59 day lag between receipt of service and payment). Staff costs are likely to be paid close to contemporaneously with the provision of the service. Other costs incurred may have average payment terms of around 7-14 days.

56 Covering regulated and unregulated customers in 2005/06.

57 It is worth noting that this is probably a downward biased estimate as it includes large industrial customers for whom the margin on sales is likely to be considerably lower than for customers with less than 160 MWh (or, put another way, customer acquisition costs are likely to be a lower percentage of total value of sales). As a consequence, including these customers in the calculation of the average bill will result in a downward biased estimate of the contribution to retail margin for smaller retail customers.

If energy and NOUS costs account for around 45% each of the new entrant's expenditures then working capital will account for around one months revenues - as per the below table.

Table 6.1
Calculation of Working Capital

	Average Outstanding	Days	Percentage of Total Revenue/Expense	Contribution to total
Revenue	71		100%	71
NUOS	-59		45%	-26.5
NEMMCO	-32.5		45%	-14.6
Other	-7		10%	-0.7
Net average				**29.1**

For the purpose of this report, we have assumed that working capital is around 1 months of retail revenue. One month of working capital at a WACC of 8% contributes 0.7% to the required margin.[58] Based on an average bill for Integral's total customer base, one month of revenue was worth around $110 in 2004/05.

Conclusion 6.2

Assuming working capital represents around 1 month of retail revenue, working capital contributes around 0.7% to the retail margin.

6.3. Compensation for hedging and other risk

When there is no regulatory asset base to act as a 'buffer' capable of absorbing shocks and preventing insolvency, it becomes acutely important that compensation for asymmetric risks be explicitly included in the regulatory determination. The Victorian ESC has recognised this in its recent Pacific National rail access determination where an 8% margin on operating cost was allowed in compensation for such risks (Pacific National has no regulatory asset base as its rail assets were gifted to it by the Victorian Government).[59]

The absence of a regulatory asset base in electricity retailing poses the same problems. In fact, the need for explicit compensation for such risks is even more acute due to the greater exposure to volatility in NEM prices and the greater risks associated with events such as 'billing malfunctions' that was an important contributor to the collapse of OneTel.[60] In order to attract equity and debt finance an electricity retailer would have to provide compensation to investors for these risks.

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58 ie, 0.08/12 = 0.66666

59 Essential Services Commission, Pacific National - Proposed Access Arrangement Final Decision, May 2006, page 93.

60 See, for example, http://www.consensus.com.au/ITWritersAwards/ITWarchive/ITWentries02/I9AgnesKing.htm where it is suggested that "One.Tel's billing system is riddled with errors, sometimes failing to generate bills and compounding already hefty overheads". Also see, http://www.theage.com.au/articles/2002/08/08/1028157993074.html for similar suggestions.

While it is difficult to quantify the cost of such risks, we note that IPART allowed a 2% margin previously and this was intended to cover a return on tangible assets plus asymmetric risks not covered elsewhere (with the explicit exclusion of energy purchase risks which IPART excluded due to the existence of the ETEF). We estimate that the return on tangible assets contributes around 0.7% to the margin. This suggests that IPART implicitly allowed a 1.3% margin for asymmetric risks.

If we accept a 1.3% margin covers these risks and add a further 0.7% compensation for energy purchase risks faced by a new entrant (who does not have access to ETEF) then an allowance of 2% is derived. We consider that this is likely to be a conservative estimate.

Conclusion 6.3

An allowance of at least 2% in the retail margin for asymmetric risks is appropriate.

The necessary compensation for this risk can reasonably be argued to be higher to the extent that the form of price control regulation forces retailers to bear even higher risk because it further constrains increases in prices to reflect increases in costs.

As the point of interaction between end use customers and all upstream electricity supply chain participants, retailers are susceptible to any and all variations in electricity supply costs. While many of these costs can be reasonably foreseen, as this review attempts to do, there remain instances where retailers can be exposed to cost/price squeeze risks that are beyond their control. This is particularly the case where retailers are restricted in their price adjustments as occurs in the current approach to regulated retail tariffs.

There is no reason why such risks should be borne by retailers unless they are compensated, particularly if regulation prevents them from passing on cost increases via price adjustments. In recognition of this fact, some international regulators include pass through mechanisms in the retail price controls for the periodic pass through of unforeseen or uncertain costs.

For example, in its 2005 retail price direction decision the Irish Commission for Energy Regulation (CER) included a U_t factor in its price control for the pass through of uncertain costs. The CER identify that:

> *'Uncertain costs are defined as those that could not reasonably be foreseen by the business and comprise elements such as:*
> - *Single Electricity Market related costs and other costs related to market opening*
> - *Changes in legislation or regulation that impose a cost or provide a benefit to PES*
> - *Restructuring costs driven by changes in legislation'*[61]

In the current Australian legislative and regulatory setting there are a number of future changes which can be expected to impact NSW retailers during the next price control period. Many of these changes are too early in their conception to be able to reasonably foresee the

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[61] CER, 2006-2010 ESB Price Control Review – Public Electricity Supply - A Consultation Paper, 26 July 2005, page 21.

likely cost impost on retailers. Such costs may best be accounted for via a pass through mechanism of the form adopted by the CER.

For example, the COAG agreement to roll out time-of-use meters may impose unforseen costs on retailers. These may take the form of additional data processing costs through to the costs of paying time of use network tariffs whilst being required to sustain customers on regulated tariffs where the various peak, off-peak and shoulder period may not align.

In addition to unforeseen or uncertain cost pass throughs, many regulators also include a specific periodic pass through mechanism for changes in the price of wholesale energy. This is the case in Ireland where the CER allows retailers to recover annually changes in the price of wholesale energy. This approach is also adopted in several states of the US including Maine, Rhode Island, New York and Texas where prices for provider of last resort (POLR) service have been regularly adjusted to reflect changes in wholesale prices.

6.4. Contribution of tangible assets to the retail margin

A new entrant will require compensation for the capital financing costs and deprecation in the value of its tangible assets. As discussed in section 3.2, we have based our estimate of these costs for a new entrant on Integral's historic book value (ie, no inflation adjustment and before depreciation) of tangible retail assets. We regard this as conservative because:

- Integral's historic book values provide no compensation for inflation - in reality a new entrant would have to buy these assets at today's prices and not the prices in existence when Integral purchased these assets;
- Integral's historic book values include no amounts to reflect the establishment costs a new entrant would face - such as feasibility studies, capital raising costs, staff recruitment and other costs associated with project managing entry in to the market;
- Integral's historic retail book values involve an allocation of common costs between its retail and network business. A stand alone new entrant retailer would have to recover all these costs from its retailing operations;
- A new entrant would not also own the associated distribution network, resulting it in being likely to face additional B2B costs not currently incurred by Integral; and
- The billing systems a new entrant would need to put in place would most likely need to have the ability to issue time of use bills, in the light of COAG's agreement to roll out time-of-use meters. Integral's current billing system does not have this capability for all mass market customers.

NERA has applied an 8% WACC to the book value of Integral's assets in order to calculate the required return on and of assets. An allowance in the retail margin of around 0.68% and 0.79% is required to compensate for return on and of tangible assets.

Conclusion 6.4

An allowance in the retail margin of around 0.68% and 0.79% is required to compensate for return on and of tangible assets.

6.5. Appropriate Range for the Retail Margin

Based on each of the conclusions listed above, the total margin required adds to 10% (see middle column of table 6.3 below). This reflects what we believe to be a conservative estimate of the probable margin a new entrant will require. However, it is useful to examine the implications of changing some of the above assumptions on the total margin allowed.

Table 6.2
Sensitivity Analysis

Assumption / Contribution to margin	Low	Medium	High
Customer acquisition costs	300	524	700
WACC	6%	8%	10%
Average customer life in years (new entrant)	7	10	13
Working capital	1mth revenue	1mth revenue	1mth revenue
Contribution of customer acquisition costs	4.1%	5.9%	7.5%
Contribution of working capital	0.5%	0.7%	0.8%
Contribution for asymmetric risk	1%	2%	3%
Contribution for return on physical assets	0.5%	0.7%	0.8%
Contribution for return of physical assets	0.8%	0.8%	0.8%
Total	**6.9%**	**10.0%**	**12.9%**

The above assumptions illustrate the impact of changes in assumptions relating to: the value of customer acquisition costs; the WACC; the average life of a customer; and the contribution for asymmetric risk.

It is worth noting that in the above table the higher are customer acquisition costs the longer is the average life of the customer. This means that the impact of assuming higher customer acquisition costs is partly offset by assuming a longer life over which those costs must be recovered. This is a deliberate reflection of the fact that simultaneously assuming high customer acquisition costs and short customer lives involves an element of 'double counting' - ie, high amounts would not be paid to acquire customer groups with short lives.

We regard a margin of 6.9% at the extreme lower end of that which would allow a new entrant to recover its costs. Similarly, a margin of 12.9% is at the extreme upper end of the margin a new entrant would require.

It should also be noted that these margin estimates have been quantified as a $/customer amount and then expressed as a percentage of the total costs, based on 2005/6 figures. To the extent that total estimated annual costs for regulated retail tariffs are expected to increase over the 2007-10 period as a result of higher energy cost and operating cost estimates for a new entrant retailer, the margin expressed as a percentage of costs will fall.

Conclusion 6.5

The appropriate range for the retail margin for a mass market new entrant is 6.9%-12.9%, with a best estimate of 10.0%.

6.6. Comparison with other market evidence

By assessing the per customer profit earned by current retailers it is possible to identify the current implied retail margins being earned in the market. Table 6.3 provides details of the reported margins of the Australian retail operations of AGL and Origin over the past four years. These margins exclude the margin earned by the associated network businesses, and cover both electricity and gas retailing. The margins are across all customers - including large industrial customers. Given that large customers will tend to have smaller margins than small customers (reflecting smaller customer interaction costs as a percentage of total energy sales) the below numbers are likely to be material underestimates of the margins earned on small customers.

For AGL we have been able to gather EBIT[62] to Sales data for their energy retailing business over the last four years. For Origin we have been able to gather EBITDA[63] to sales data for their energy retailing business[64] over the same period. In effect, EBIT/sales represents AGL's margin to compensation for a post tax return on capital ('interest' and 'taxes')[65]. Origin's EBITDA reflects the compensation for a post tax return on capital ('interest' and 'taxes') plus compensation for reductions in the value of that capital ('depreciation' and 'amortisation').

EBITDA to sales is the relevant comparison for our proposed margin because our margin includes compensation for all of interest, tax, depreciation and amortisation (ie, our proposed margin compensates for interest, tax and depreciation/amortization of tangible/physical assets).

62 Earnings before interest and tax.

63 Earnings before interest tax depreciation and amortisation.

64 This includes energy retailing of electricity and gas to both residential and commercial customers.

65 Plus compensation for asymmetric risk (ie, for losses associated with a events that that had a positive probability of occurring but did not in the relevant year).

Table 6.3
Implied retailer margins from publicly listed Australian energy retailers

Retailer	Margin Measure	Average	2005/06*	2004/05	2003/04	2002/03
AGL	EBIT / Sales #	7.40%	8.80%	8.20%	6.30%	6.30%
Origin	EBITDA / Sales	8.70%	8.80%	9.90%	7.9%	8.2%

Source: AGL: AGL results for the six months to 31 December 2005 Highlights, 2005 Annual Report, 2004 Annual Report, 2003 Annual Report, 2002 Annual Report
Origin: Origin Half Yearly Report to Shareholders, 2005 Annual Report, 2004 Annual Report, 2003 Annual Report, 2002 Annual Report

*Notes: * Based on 6 month result.*
 # EBITDA (earnings before interest, taxes, depreciation and amortisation) is a more appropriate measure of retailer margin than EBIT. We would reasonably expect the EBIT / sales margin to underestimate the margin relative to the EBITDA / sales margin
** Margins relate to electricity and gas retailing and exclude networks..*

Origin's average EBITDA to sales margin has been 8.7% for the four most recent years. This is well within, and towards the middle of, the range we have calculated above.

We would expect AGL's EBIT to sales ratio to be below our range because it does not include compensation for depreciation or amortisation. Nonetheless, its average value has been 7.4% which is within the above range. Moreover, the combined contribution of amortisation and depreciation to our best estimates of the retail margin exceed 2%. If AGL's EBITDA to sales ratio is estimated by adding 2% to its EBIT to sales ratio then an average margin of 9.4% is calculated - which is again towards the middle of our range.

This market evidence of the margin earned by incumbent players supports our estimate of the margin required by new entrants in electricity retailing. It strongly supports an increase in the margin well above the current 2%.

6.7. Comparison with IPART's 2004 Determination

We believe that a move from the 2% margin allowed by IPART in 2004 to 10% can be justified on the following grounds:

- IPART's 2% included no return on customer acquisition costs. While this may be justified when setting efficient costs for an incumbent retailer that has a legislatively inherited customer base, it is not appropriate when estimating costs for a new entrant (as is required by the Minister's Terms of Reference). This difference accounts for a 5.9% increase in margin.
- IPART's 2% did not include compensation for depreciation of tangible assets. This accounts for an increase of around 0.8% in the margin. This would be offset by a reduction in the operating costs estimate, which would exclude depreciation.
- IPART's 2% appears to include no explicit compensation for return on working capital in the margin and it is not clear whether an allowance was made within operating costs to compensate for working capital in 2004. This accounts for an increase of around 0.7%.

- IPART's 2% was set in the context of 100% hedging through ETEF. A new entrant will not have such hedging available and, hence, will inevitably be exposed to a greater level of risk. A conservative estimate of the cost of this risk is around 0.7%.

It is worth noting that ESCOSA's 5% margin explicitly included customer acquisition costs. However, it based its estimate on the price paid for ETSA's customers in South Australia - which was the lowest of all observations in Australia and the third lowest internationally. While this may have been appropriate given it was the actual price paid by AGL, it is more appropriate to use all the available observations when inferring a customer acquisition cost for a new entrant in NSW.

7. Approach To Determining Operating Costs for a New Entrant

This final section sets out some proposed principles for determining the appropriate allowance for operating costs for a mass market new entrant.

7.1. Operating Costs to be Estimated for a Stand-alone Retail Business

We have used Integral's operating costs in this report as a proxy for the operating costs a mass market new entrant would incur. This is likely to be conservative in a number of respects, including:

- Integral is not an established incumbent and, therefore, its costs will not include the establishment costs associated with new entry (eg, the additional expenditures associated with establishing operations compared to maintaining operations);

- Integral is an established network distribution business and, as a result, its retail operating costs reflect a sharing of 'overheads' with its network business. A new entrant in NSW would not be able to share operating cost overheads with a network business;

- There are likely to be certain synergies that Integral enjoys as a result of its incumbent network distribution position that a new entrant would not enjoy. As a matter of history, Integral's operational systems will have evolved in a manner that takes into account the needs of both its retail and network operations. Any cost advantages associated with this will not be enjoyed by new entrants. Examples of such cost advantages include branding advantages that Integral enjoys as an incumbent distributor/retailer and IT systems advantages that Integral enjoys as an incumbent distributor/retailer.

To ensure that using Integral's costs does not underestimate the costs of a new entrant it would be necessary to ask Integral to perform a cost study that attempted to identify the above synergies and add them back into actual operating costs. Integral has not done this for this report. However, it would be appropriate for any information request from IPART to ask retailers to attempt to do so.

7.2. Consistency Between Costs Included in the Retail Margin and Those Included in Operating Costs

As stressed throughout this report, it is important that all relevant costs are reflected in the estimate of the appropriate level of regulated retail tariffs. Exactly where those costs are reflected is of secondary importance, ie, whether they are incorporated within the estimates of the retail margin, retail costs or energy costs.

Section 5.3 of this report set out a proposed allocation of costs to the retail margin. If this allocation is adopted by IPART, then the categories of costs identified would need to be excluded from the operating costs estimates.

Specifically this implies that the following cost categories would *not* form part of Integral Energy's estimate of retail costs:

- Depreciation of physical assets
- The return on physical assets
- Customer acquisition costs
- Working capital.

An allowance for the cost of bad debt would need to be included in the operating costs estimate.

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