Mass market new entrant retail costs and retail margin

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1 Introduction

Full retail contestability was introduced in the NSW electricity market on 1 January 2002. Since then, small retail customers, who consume electricity at less than 160MWh per year, have been able to choose their retail electricity supplier and negotiate a contract with that supplier. Small retail customers who do not enter a negotiated contract are supplied by standard retailers under standard form contracts. The Independent Pricing and Regulatory Tribunal of NSW (IPART) is responsible for setting the regulated price of standard form contracts.

The existing determination on regulated prices will expire on 30 June 2007. The Minister for Energy has asked IPART to investigate and determine the regulated price of standard form contracts that will apply from 1 July 2007 until 30 June 2010.

As part of its current investigation and determination, IPART has engaged Frontier Economics (Frontier) in conjunction with Strategic Finance Group Consulting (SFG Consulting) to develop cost allowances for mass market new entrant (MMNE) retail costs and retail margin. The analysis is to consider each year in the determination period, with a focus on the position in 2010. The analysis is also to highlight any significant differences between the costs of a standard retailer and the costs of a MMNE.

IPART has also engaged Frontier to provide advice on the cost range that should be allowed for energy costs in determining regulated prices. Frontier has provided IPART with a separate draft report on energy costs.[1]

This draft report sets out the results of Frontier's assessment of appropriate allowances for MMNE retail costs and retail margin. This draft report will be released for public comment. Frontier will then produce a final report.

This report is structured as follows:

- Section 2 discusses the Terms of Reference relevant to the estimation of retail costs and retail margin, and our interpretation of those Terms of Reference;
- Section 3 discusses the relationship between the energy costs, retail costs and retail margin that a MMNE would incur, and our framework for estimating these costs consistently;
- Section 4 sets out our estimate of an appropriate range for MMNE retail costs for each year from 2007/08 to 2009/10; and
- Section 5 sets out our estimate of an appropriate range for the MMNE retail margin.

[1] Frontier Economics, *Energy costs*, Draft Report, December 2006.

2 The Terms of Reference

The Terms of Reference (ToR) for the current investigation and determination require that "regulated retail tariffs and regulated retail charges are at cost reflective levels … for all small retail customers by 30 June 2010".

The ToR also require an allowance for both "mass market new entrant retail costs" and "mass market new entrant retail margin", with a MMNE defined as "a new market entrant that is of sufficient size to achieve economies of scale."

In practice, a MMNE could take many forms, and its assumed form could impact on the costs that it would face. In defining a MMNE there are two key questions: the scale of the MMNE's operations and the scope of the MMNE's operations. In each case, our interpretation of a MMNE is grounded in our understanding of how market entry is likely to occur in practice.

2.1 SCALE OF A MMNE

Entrants can be divided into two kinds: those that target the mass market and those that focus on specific customer classes. It is clear that the ToR require the Tribunal to consider the former.

In targeting the mass market, there are likely to be some economies of scale available to retailers due to the fixed costs associated with retailing. The ToR require us to consider a new entrant that is able to achieve these economies of scale. In practice, we consider it most likely that a new entrant that achieves economies of scale would be an existing retail business with a large customer base outside NSW, so that the new entrant is able to use its existing systems to enter the mass market in NSW. Examples include AGL, TRUenergy and Origin Energy. Generally, these are large-scale retailers serving retail customers across the NEM. These businesses are of a scale similar to, or larger than, the standard retailers in NSW.

The evidence suggests that, with regard to electricity retailers' operating costs, the average cost curve is quite flat over a wide range of customer numbers. In other words, while there are economies of scale associated with retailing, these are largely achieved with relatively low customer numbers, so that retailers operating at different scales can achieve similar average costs.

In the first instance this can be demonstrated by the survival of smaller retailers operating, apparently successfully, for some period. For example, Victoria Electricity reportedly serves a mix of some 100,000 mostly small to medium customers.[2] Also, Powerdirect, a business founded nearly 10 years ago and recently sold to a Queensland Government retailer (Ergon), served about 50,000 mostly larger industrial and commercial customers.

These examples suggest that relatively small retailers are competitive with the larger businesses, even when these retail minnows compete in the intensely

[2] See Victoria Electricity website: http://www.victoriaelectricity.com.au/?home/news

competitive market for larger electricity customers. We also note that other new entrant retailers are planning ambitious entry strategies, indicating that the economies of scale are not so great to deter entry.[3]

The existence of a relatively flat average cost curve also seems to be supported by the standard retailers' own data, at least over the output range represented by the standard retailers. Examining retailers' actual costs and customer numbers since 2002/03 suggests that the cost curve is relatively flat over the scale of these businesses, which have varied in size by around 100 per cent.

The literature also supports the presence of a long, flat average cost curve. There are several studies of economies of scale in electricity *distribution* that find that the cost curve flattens out at a relatively small scale. Giles and Wyatt find that distributors in New Zealand (who were also retailers when the study was conducted) achieve efficient scale at an output between 500 and 3,500 GWh (which Yatchew suggests implies a customer base of 30,000).[4] Salvanes and Tjotta find the efficient scale for distributors in Norway is achieved with about 20,000 customers.[5] Yatchew finds similar results for Canada, with electricity distributors achieving efficient scale with about 20,000 customers.[6]

Given that electricity distributors have larger fixed costs than electricity retailers, these results suggests that the efficient scale of electricity retailers can also be achieved at a relatively modest scale. This is supported by Kwoka, who examines the scale economies available to electricity retailers/distributors as a result of both their distribution function and their retail (supply) function.[7] Kwoka concludes:

> … while there are measurable scale effects with respect to both output and customer numbers, for the most part the relationship is relatively flat. There is evidence of a significant fall in costs at quite small outputs, and evidence of a rise at the largest volumes, but unit costs do not otherwise change much across a rather wide range of outputs. This implies that utilities that vary considerably in size may nonetheless remain fairly cost-competitive and viable in this industry.
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> Disaggregation of costs into the wires and supply functions has further implications for industry restructuring. The evidence suggests that wires remains characterized by high scale, consistent with most proposals that it continue as a

[3] See Australian Power&Gas http://www.australianpowerandgas.com.au/

[4] Giles, D and Wyatt, N (1993) "Economies of scale in the New Zealand electricity distribution industry", in Phillips, P. (ed.) *Models, Methods and Applications of Econometrics, Blackwell*, Oxford, 370-382. Cited in Yatchew, A. (2000) "Scale Economics in Electricity Distribution: A Semiparametric Analysis", 15 *Journal of Applied Econometrics* 187.

[5] Salvanes, K and Tjotta, S (1998) "A test for natural monopoly with application to Norwegian electricity distribution", 13 *Review of Industrial Organization* 669. Cited in Yatchew, A. (2000) "Scale Economics in Electricity Distribution: A Semiparametric Analysis", 15 *Journal of Applied Econometrics* 187.

[6] Yatchew, A. (2000) "Scale Economics in Electricity Distribution: A Semiparametric Analysis", 15 *Journal of Applied Econometrics* 187.

[7] Kwoka, J (2005) "Electric power distribution: economies of scale, mergers, and restructuring", 37 *Applied Economics* 2373.

regulated monopoly. By contrast, supply would appear potentially competitive in that scale effects, while not absent, are much smaller except at very small sizes.[8]

That the average cost curve is flat over a wide scale has important implications for the estimation of MMNE retail costs. First, the particular scale at which a MMNE operates is unlikely to materially affect the estimated costs of a MMNE. In Frontier's view, whether a MMNE has 250,000 customers, as suggested by EnergyAustralia in their submission to IPART, or is the size of the standard retailers in NSW, the MMNE is likely to have similar average costs.

More importantly, that the average cost curve is flat over a wide scale suggests that the standard retailers have each achieved economies of scale. Each of the standard retailers has a large customer base. Indeed they are among some of the largest electricity retailers in Australia. As a result, the retail costs of the standard retailers ought to provide a reasonable estimate of the retail costs of a MMNE. This has important methodological implications: rather than determining the scale at which a MMNE would have to operate and then estimating the costs that the MMNE would incur at that scale, we consider it to be more in keeping with the ToR to estimate the costs that a retailer operating at efficient scale would achieve and assume that a MMNE would reach whatever scale is necessary to operate at that level of average cost.

2.2 SCOPE OF A MMNE

The second question that is relevant to the definition of the MMNE is the scope of the MMNE's operations. While the ToR require that a MMNE is of sufficient size to achieve economies of scale, the ToR are silent on whether a MMNE is integrated into distribution, generation or other retailing activities.

If a MMNE is a gas and electricity retailer, there are likely to be some economies available. However, these economies are likely principally to be economies of *scale* resulting from an increased customer base. As required by the ToR, we consider a MMNE to have achieved economies of scale – whether the MMNE achieves these economies of scale as a result of retailing electricity only, or retailing electricity and gas, is of no practical importance.

In principal, there may also be some economies of *scope* available if a MMNE is an electricity and gas retailer, particularly if the MMNE offers dual fuels contracts to its customers. Any such savings will be savings in the variable costs of retailing, as a retailer is able to serve two customers for the price of one. However, as discussed in detail in this report, the majority of retailing costs are fixed, meaning that any savings in the customer-driven costs of retailing are likely to account for only a small proportion of total costs. Also, it is unclear in practice that dual fuel contracts will enable retailers to reduce their customer-driven costs of retailing.[9] For these reasons, we do not consider that the MMNE being a dual fuel retailer would have a material effect on estimated costs.

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[8] Kwoka, J (2005) "Electric power distribution: economies of scale, mergers, and restructuring", 37 *Applied Economics* 2373 at 2385.

[9] In its review of retail competition, the ESC considers the economies available from dual fuel offers:

The conclusion that most of the economies available from dual-fuel retailing are economies of scale is supported by the literature. Sing examined joint supply of gas and electricity, and found that there were diseconomies. He concluded that "factors other than cost savings are responsible for the existence of combination utilities."[10] Similarly, Fraquelli, Piacenza and Vannoni find evidence that small utilities enjoy economies from diversifying into the supply of multiple utilities (gas, water and electricity), but do not find evidence that larger utilities enjoy economies from doing so.[11] This supports the view that the principal benefit of diversification may be the economies of scale available from spreading fixed costs over a larger customer base, economies that a large utility achieves without diversification.

There may also be some benefits available to a MMNE if it is vertically integrated into electricity distribution or generation.

Considering generation, there are likely to be some risk management benefits available to a retailer that is vertically integrated into generation. In effect, owning generation assets acts as a hedge for a retailer: because the returns to retailing and generation are negatively correlated (for example, when electricity prices increase the returns to retailing decrease but the returns to generation increase) a retailer/generator faces lower risk than a stand-alone retailer. In short, there are benefits associated with diversification. These benefits would be reflected in the retail margin: since a retailer/generator faces less risk, the retail margin appropriate to a retailer/generator is lower than the retail margin appropriate to a stand-alone retailer. Interpreting the MMNE as a stand-alone retailer therefore leads to a higher estimate of the retail margin than would interpreting the MMNE as a retailer/generator.

Considering distribution, there are likely to be some economies of scope available to a retailer that is vertically integrated into distribution. These economies of scope would arise as a result of spreading fixed costs over a wider range of activities. In particular, the customer information systems that a retailer requires

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> "It is interesting to note that new non-local retailers largely do not have dual fuel capabilities and did not see this as a disadvantage. It is not clear that expected economies have emerged thus far for local retailers. While dual fuel offers have the potential to provide economies by allowing a retailer to serve two customers for the price of one, the potential benefit may be reduced for a number of reasons:
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> • retailers offering dual fuel products may not have fully integrated back office systems, thus effectively incurring the same costs as with two separate supplies; and
>
> • different metering and billing processes between the electricity and gas markets may limit the integration opportunities."
>
> ESC, *Special Investigation: Review of Effectiveness of Retail Competition and Consumer Safety Net in Gas and Electricity: Background Report*, June 2004, page 27.

10 Sing, M (1987) "Are combination gas and electric utilities multi-product natural monopolies?", 69 *Review of Economics and Statistics* 392. Cited in Fraquelli, G, Piacenza, M and Vannoni, D (2004) "Scope and scale economics in multi-utilities: evidence from gas, water and electric combinations", 36 *Applied Economics* 2045.

11 Fraquelli, G, Piacenza, M and Vannoni, D (2004) "Scope and scale economics in multi-utilities: evidence from gas, water and electric combinations", 36 *Applied Economics* 2045.

can also be used by a distributor. A retailer/distributor can therefore recover these costs over a wider range of activities, leading to lower average costs.

It is difficult to assess the extent of any cost savings available through vertical integration. We are not aware of any literature specifically examining the economies of scope available through vertical integration of the retailing and generation functions or the retailing and distribution functions. However, there is a wide literature on the economies of scope available through the vertical integration of the electricity supply chain in general. Much of this literature is concerned with vertical integration of generation with transmission and distribution, and reports significant economies of scope. Recently, Kwoka estimated economies of vertical integration of generation with distribution of between 3 per cent and 57 per cent, depending on scale.[12] Nemoto and Goto report cost savings of up to 3 per cent for integration of generation with transmission and distribution.[13] Studies of vertical integration across the whole supply chain (generation, transmission, distribution and retailing) are less common. Recently, Piacenza and Vannoni report economies of vertical integration across the entire supply chain in the order of 8 per cent of costs.[14]

This suggests that interpreting the MMNE as a vertically integrated retailer/generator could lead to lower estimates of the MMNE's costs, in particular its retail margin. This also suggests that interpreting the MMNE as a vertically integrated retailer/distributor could lead to lower estimates of the MMNE's costs. Importantly, however, since each of the standard retailers are stapled retailer/distributors, their reported retail costs may be lower than those available to a stand-alone MMNE. Using the standard retailers' reported costs as a proxy for the retail costs of a MMNE therefore risks understating the retail costs that a stand-alone MMNE would face. In any case, it is difficult to determine the extent of the available economies of scope.

2.3 CONCLUSION ON MMNE

While recognising that the concept of a MMNE is very much a hypothetical construct, Frontier uses the costs that large-scale retailers operating elsewhere in the NEM would face on entering the mass market in NSW as the basis for estimating the costs of a MMNE. This approach is consistent with the overall thrust of the ToR, which seek to ensure that energy costs reflect *actual* costs facing retailers. If the allowed retail costs reflected artificially high costs of a business that would never exist or survive in the context of a competitive retail market this would provide the standard retailers with an unfair revenue advantage over potential new entrant retailers, making it difficult to compete and possibly eroding the competition that currently exists.

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12 Kwoka, J (2002) "Vertical Economies in Electric Power: Evidence on Integration and Its Alternative", 20 *International Journal of Industrial Organization* 653.

13 Nemoto, J and Goto, M (2004) "Technological Externalities and Economies of Vertical Integration in the Electric Utility Industry", 22 *International Journal of Industrial Organization* 67.

14 Piacenza, M and Vannoni, D (2005) "Vertical and Horizontal Economies in the Electric Utility Industry: An Integrated Approach", *Hermes Working Paper*.

We interpret the MMNE to be an entrant that has achieved economies of scale. The evidence suggests that this occurs at a modest scale. However, our interpretation of the MMNE as a stand-alone new entrant implies that the MMNE may not achieve all economies of scope, particularly those available through vertical integration. Because we have used the costs of integrated retailers/distributors as a proxy for the costs of a MMNE, potentially the cost estimate may understate the costs of a stand-alone MMNE.

3 Relationship between retail costs, retail margin and energy costs

Some of the costs that a MMNE would face can reasonably be allowed for in more than one of energy costs, retail costs or retail margin. This creates a degree of discretion in the estimation of appropriate cost allowances, and highlights the importance of adopting a consistent approach. If a consistent approach is not adopted, costs may be overlooked or may be double counted. Of particular relevance to the cost allowances estimated by Frontier in this report and in Frontier's energy cost report, there is the potential that costs may be double counted in the allowance for energy costs and the allowance for retail margin, or in the allowance for retail costs and the allowance for retail margin.

3.1 ENERGY COSTS AND RETAIL MARGIN

A principal difference between IPART's current review of regulated retail electricity prices and IPART's previous reviews is that IPART's previous reviews have all taken place in the presence of either vesting contracts or the Electricity Tariff Equalisation Fund (ETEF). During the regulatory period for the current review, the ETEF will cease. As a result, retailers will be exposed to increasing energy purchase risk in NSW, which must be reflected in regulated prices.

As discussed in detail in Frontier's report on energy costs, there is a relationship between energy costs and energy purchase risks: the more willing a retailer is to be exposed to energy purchase risk, the lower the retailer's energy costs. Given the high price of completely hedging against energy purchase risk, all retailers are likely to be exposed to some residual energy purchase risk. As a result, there is an important link between the appropriate allowance for energy costs and the appropriate allowance for retail margin. As discussed in detail in Section 5 of this report, Frontier's analysis ensures a consistent approach to energy purchase risk.

3.2 RETAIL COSTS AND RETAIL MARGIN

Frontier has also used a consistent approach to estimating an allowance for retail costs and retail margin. Some costs and risks could reasonably be included in either the allowance for retail costs or the allowance for retail margin. The choice between allocating a particular cost or risk to the retail costs or the retail margin should not materially affect the results of the price review, as long as a consistent approach is adopted. Frontier ensures that allowance is made for each relevant cost and risk, and no cost or risk is counted twice:

- The principal cost component included in the allowance for retail costs is operating expenditure associated with retailing to small customers. Also included are customer acquisition costs that would be faced by a MMNE. Specific elements of the allowance for retail costs are discussion in Section 4.
- Costs components included in the allowance for retail margin include return on capital (given the risks faced by the retailer that are not allowed for

elsewhere) and depreciation. Specific elements of the allowance for retail margin are discussed in Section 5.

4 MMNE retail costs

There are two broad categories of retail costs that are incurred by a MMNE:

- The costs that a MMNE would incur in acquiring customers. These costs are primarily marketing costs, but also include the costs of transferring customers. We estimate an allowance for customer acquisition costs per customer per annum (CAC).
- The operating expenditures that a MMNE would incur in retailing to small customers. These costs include, among other things, the costs of billing and revenue collection, call centres and corporate costs. We estimate an allowance for retail operating costs per customer per annum (ROC).

This section estimates a range for the CAC and the ROC that a MMNE would incur for each year from 2007/08 to 2009/10. These two estimates are then combined to provide an estimate of the total retail costs for a MMNE to acquire and supply customers in the NSW electricity retail market.

4.1 METHODOLOGY

Each of CAC and ROC is estimated using two approaches: the bottom-up cost approach and benchmarking.

The **bottom-up cost approach** builds up an estimate for each of CAC and ROC from the separate component of these costs. The data for the bottom-up approach are primarily sourced from responses to the information request provided by standard retailers in NSW. As discussed in Section 1, information on retail costs from the standard retailers is a relevant proxy for the costs that would be incurred by a MMNE because the standard retailers enjoy similar economies of scale to the type of business that we would expect to enter the mass market in NSW. As a result, the efficient costs of the standard retailers and of a MMNE will be similar. Where there is reason to expect that the CAC or ROC estimates of the standard retailers differ from those that would be incurred by a MMNE, this is discussed in the sections that follow.

The **benchmarking approach** examines allowances for electricity retail costs from regulatory decisions in other jurisdictions, and estimates an appropriate allowance based on these benchmarks. Information on cost allowances from other jurisdictions is a relevant proxy for the costs that a MMNE would incur because these allowances are based on the costs of the same large retailers that we would expect to enter the mass market in NSW. Where there is reason to expect that cost allowances for retailers in other jurisdictions should differ from cost allowances for a MMNE, this is discussed in the sections that follow.

4.2 BOTTOM-UP ESTIMATE OF CAC

The data provided by standard retailers in relation to the costs of acquiring customers can be used as a guide to the CAC that would be incurred by a MMNE. This section uses these data to estimate the CAC that a MMNE would incur for each year from 2007/08 to 2009/10.

4.2.1 Information request

The information request asked the standard retailers to report those of their costs that are directly related to acquiring new residential customers and new business customers, broken down into any relevant components. Actual costs per new customer were requested for financial years from 2002/03 to 2005/06, and forecast costs per new customer were requested for financial years from 2006/07 to 2009/10.

The information request also asked the standard retailers to estimate the average number of years that residential customers on negotiated contracts, and business customers on negotiated contracts, stay with a retailer. Estimates for financial years from 2002/03 to 2009/10 were requested.

4.2.2 Estimating CAC

Retailers were asked to estimate the *total* cost of acquiring a new customer. However, the costs of acquiring a new customer need not be recovered in a single year. Rather, these costs should be recovered over the expected life of the new customer. Therefore, to develop a cost allowance for CAC, the total cost of acquiring a new customer in any given year, as reported by the retailers, needs to be converted to a CAC.

In order to amortise the costs of acquiring a new customer, three variables must be specified: the total cost of acquiring a new customer, the number of years over which these costs should be amortised, and the discount rate. An allowance for CAC is estimated using, to the extent possible, the data provided by each of the standard retailers:

- Retailers reported the total cost of acquiring a new residential customer and the total cost of acquiring a new business customer. These estimated costs or, where appropriate, the low-point and high-point of the range of these costs, are amortised. This provides separate estimates for CAC for residential customers and business customers.
- For each of the retailers, the costs of acquiring a new customer are amortised over that retailer's estimate of the expected number of years that the customer will remain with the retailer. Where a retailer provided a range for the number of years it expects to retain a customer, both the low point and the high point of the range are used. Where a retailer did not provide an estimate for the number of years it expects to retain a customer, that retailer's reported costs of acquiring a new customer are amortised over a period ranging from the fewest years estimated by any retailer to the most years estimated by any retailer.

The retailers were not asked to estimate a discount rate. For each of the retailers we use a discount rate of 8 per cent. This point estimate is consistent with the discount rate used to determine the appropriate retail margin in Section 5. Furthermore, it is consistent with the point estimate for real pre-tax WACC proposed by Integral Energy, and their consultants NERA Economic Consulting

(NERA), for the purposes of amortising customer acquisition costs.[15] It is also consistent with the lower end of the range for the real pre-tax WACC adopted by ESCOSA in its estimate of the appropriate retail margin for an electricity retailer in its 2005 inquiry into retail prices.[16]

4.2.3 Reasonableness of estimated CAC

The estimates of CAC in the previous section were based on the retailers' estimates of the costs of acquiring a new customer and the average number of years a customer is retained. While these data have not been audited, they can nevertheless be tested for reasonableness.

Reasonableness test 1: Total costs of acquiring a new customer

Retailers reported different views on the costs of acquiring a new customer. Importantly, Integral Energy provides estimates of the costs of acquiring new business customers using two different methods. In determining a reasonable allowance for customer acquisition costs, we used Integral Energy's estimate of the cost for that method that was consistent with the responses of other retailers.

Given this, there is a clear consensus among the retailers that the cost of acquiring a new customer – whether residential or business – is around $200. Taking the average of customer acquisition costs – excluding, as discussed, one of Integral Energy's cost estimates – provides an estimate of the reasonable cost of acquiring a new customer, whether residential or business.

Reasonableness test 2: Years a customer is retained

Retailers also reported different views on the number of years they expect to retain a new customer.

Given that the number of years that a customer is retained is unlikely to vary significantly across retail areas, this variation in the estimates provided by the retailers suggests that there is significant uncertainty about how long a customer can be expected to stay with a retailer. However, given the market has been open to competition since the beginning of 2002, retailers' estimates must, to some extent, be based on experience.

In considering customer life, we can take some guidance from the average rate at which customers change retailers. Very broadly, the more customers that change retailers each year, the fewer years a customer will be expected to remain with a retailer. Estimates of rates of churning can therefore provide an indication of the number of years that a customer will remain with a retailer.

However, estimating the churning rates that will occur in NSW in the future is very difficult. The levels of churning will depend on the extent of retail

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15 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 (Integral Energy Submission). NERA Economic Consulting, *Approach to Estimating the Retail Margin and Retail Costs for a Mass Market New Entrant*, 5 September 2006 (NERA Retail Cost and Margin Report).

16 ESCOSA, *Inquiry into Retail Electricity Price Path: Discussion Paper*, September 2004.

competition. This, in turn, will be affected by the level of regulated tariffs in the future. Therefore, rather than relying on levels of churning between retailers observed in NSW in the past, a broad view of competitive markets is appropriate. The European Commission's benchmarking reports on the electricity and gas markets in the European Union take such a view. The Third Benchmarking Report discusses the rates at which customers will change retailers in competitive markets:

> "Based on experience in those Member States which have already had a competitive market for some time, one might expect a well functioning market to have around 15-20% of businesses changing suppliers every year with most, if not all, seeking to renegotiate tariffs with their current supplier every year. For households, an annual level of switching of perhaps 10% would seem a reasonable benchmark."[17]

If all customers have similar patterns of churning, then these rates of changing suppliers suggests that a well-functioning market would see residential customers remaining with a retailer for 10 years, and business customers remaining with a retailer for about 6 years.

This is consistent with the approach and the assumptions used by NERA in their report for Integral Energy.[18] NERA noted that the ESC's *Victorian Energy Retail Comparison* states that 22% of Victorian customers changed electricity retailer in 2004/05, which means that the average life of a customer in Victoria could be five years. NERA suggested that the average life for a new customer in NSW would be ten years, presumably on the basis that changing electricity retailers occurs less frequently in NSW than in Victoria.[19] This is consistent with our view

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[17] European Commission, *Third Benchmarking Report on the Implementation of the Internal Electricity and Gas Market,* 2004.

[18] NERA Retail Cost and Margin Report. NERA considers aggregate churning levels to provide an estimate of the average life of a customer acquired by *any* means. NERA suggest that "the average life of an organically acquired customer [as opposed to a customer acquired through the purchase of a retail business] will be less than 5 years as they will, by definition, be customers who are relatively more 'footloose' (ie, customers who are attracted to switch, by definition, will have a greater propensity to switch)." While this is likely true, there is also good reason to think that customers who are acquired organically may be less likely to change retailer in future. In particular, consumer surveys in both Australian and the United Kingdom indicate that the dominant factor affecting a decision to change retailers is price. See, for example: Ofgem, *Domestic Retail Market Report – June 2005*, 7 February 2006; McGregor Tan Research, *Monitoring the Development of Energy Retail Competition – Residents: A Report Prepared for ESCOSA*, February 2006. Customers that are acquired organically have, presumably, already been offered a discount to change retailers the first time. As a result, there is less headroom available for other retailers to offer these customers sufficient discount to encourage them to change retailer a second time. In short, customers that have been organically acquired may have a greater willingness to change retailers, but it is increasingly difficult for retailers to offer these customers a price to encourage them to change retailer. As a result of these countervailing factors, we consider that aggregate churning levels provide a reasonable proxy for churning levels of organically acquired customers.

This conclusion is supported by the results of a customer survey in the United Kingdom, reported by Ofgem. The survey found that 47 per cent of customers had changed retailers once, but of those customers who had changed retailers once, only 35 per cent had then gone on to change retailers again. Ofgem, *Domestic Retail Market Report – June 2005*, 7 February 2006.

[19] The rates at which customers change energy suppliers in various jurisdictions are analysed in Peace Vaasaemg, *World Retail Energy Market Rankings*, June 2005. Ranked according to the extent to which

on the expected number of years a residential customer would be retained, and longer than our view on the expected number of years a business customer would be retained.

Given this evidence on the rate at which customers change retailers, we consider it reasonable to assume that residential customers are retained for 10 years and business customers are retained for 6 years.

4.2.4 Re-estimating CAC in light of these reasonableness tests

In order to address the divergences in retailers' estimates of the costs of acquiring customers and of customer life, we re-estimate CAC using the following assumptions:

- the total cost of acquiring a new customer is the average of the estimates provided by the retailers, using Integral Energy's estimate of the cost of acquiring a business customer in a manner that is consistent with the other retailers;
- a residential customer is retained for 10 years and a business customer is retained for 6 years; and
- the discount rate is 8 per cent.

Using these assumptions, CAC for residential customers is set out in Figure 1, and CAC for business customers is set out in Figure 2.

4.2.5 Integral Energy's proposed method for estimating CAC

Integral Energy, and its consultants NERA, have proposed an alternative method for estimating CAC.[20] The proposal is to use the price at which retail businesses have been acquired as a proxy for the cost of acquiring a new customer. The intuition is that "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."[21] Examining the price at which various retail businesses have been sold in Australia and overseas, and the number of customers that have been acquired as a result of these transactions, Integral/NERA proposes that the costs of acquiring a retail electricity customer in Australia is $524 per customer.[22]

customers change energy suppliers, Victoria came second and NSW came tenth. This supports the view that customer life in NSW is longer, on average, than in Victoria.

20 Integral Energy Submission, Section 7.4.3 and 7.7.1 and NERA Retail Cost and Margin Report, Section 3. Note, however, that Integral/NERA propose including customer acquisition costs in the allowance for retail margin, while recognising that these costs could equally be included in the allowance for retail costs.

21 NERA Retail Cost and Margin Report, page 6.

22 Intergal/NERA's analysis of the costs of acquiring retail electricity businesses did not include the recently announced purchase by Origin Energy of Sun Retail. According to Origin Energy's press release, the sale price implied a value of $1,100 per retail customer. However, in terms of EBITDA multiple, the price for Sun Retail is not out of line with valuations for other electricity retailers.

Using the price at which retail businesses have been sold as a proxy for the costs of acquiring new customers is not consistent with our interpretation of a MMNE. We consider a MMNE to be a retailer operating in a jurisdiction other than NSW that expands its existing operations into NSW. The best proxy for the costs a MMNE would face in acquiring customers in this organic way is the cost that standard retailers face in acquiring customers organically. As discussed, there is broad consensus among the retailers that the cost of acquiring customers in this way is around $200.

What Integral/NERA have estimated is the value of a retail business per customer. As discussed in Section 5.3, a MMNE that incurs the costs recommended in this report has a value per customer that is consistent with the business valuations that Integral/NERA observe.

4.2.6 Recommended range for MMNE CAC

We recommend the following ranges for MMNE CAC:

- For residential customers, we recommend that CAC be set between $25 and $30 per customer per annum, in 2006/07 dollars, for each year from 2007/08 to 2009/10. The relationship between this recommended range and the re-estimated CAC using benchmarked data, is set out in Figure 1.
- For business customers, we recommend that CAC be set between $40 and $45 per customer per annum, in 2006/07 dollars, for each year from 2007/08 to 2009/10. The relationship between this recommended range and the re-estimated CAC using benchmarked data, is set out in Figure 2.

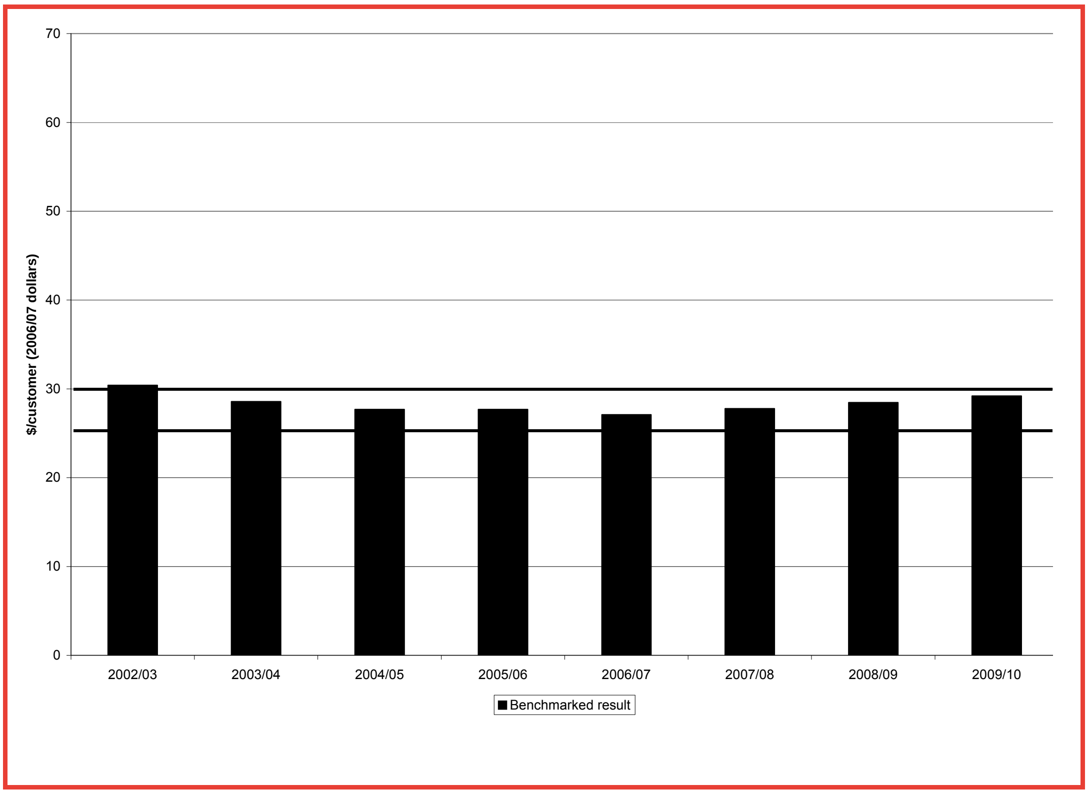

Figure 1: Recommended range for MMNE residential CAC

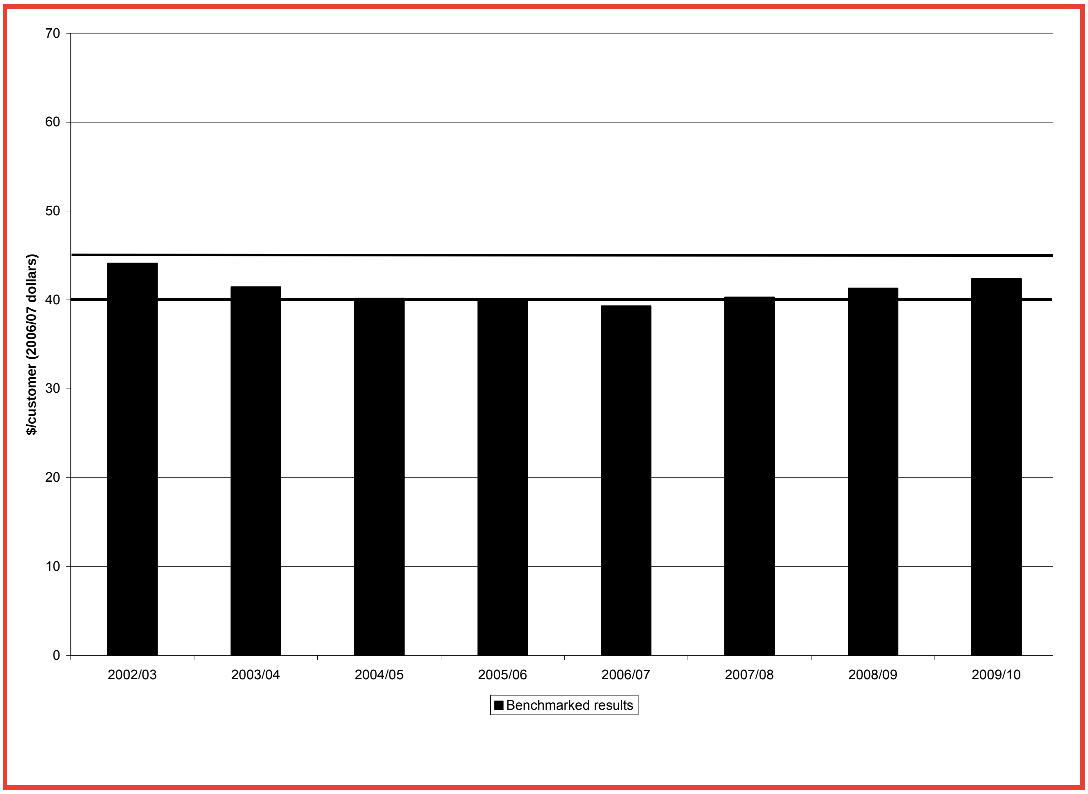

Figure 2: Recommended range for MMNE business CAC

These recommended ranges are derived substantially from data provided by the standard retailers, although this data is also benchmarked where possible. The CAC incurred by standard retailers are likely a good proxy for the CAC that would be incurred by a MMNE. As discussed in Section 1, we interpret a MMNE to be an existing retailer with a large customer base outside NSW. The MMNE is a similar business to the standard retailers. In particular, the task of acquiring a new customer is substantially the same, whether undertaken by a standard retailer looking to acquire customers in NSW or undertaken by a MMNE looking to expand from another state into NSW. In either case the retailer will face similar costs in contacting new customers (either through door-to-door sales or telemarketing) and similar costs in transferring customers.

4.3 BOTTOM-UP ESTIMATE OF ROC

The retail operating costs reported by standard retailers in NSW can be used as a guide to ROC that would be incurred by a MMNE. This section uses the data reported by retailers to estimate the ROC that a MMNE would incur for each year from 2007/08 to 2009/10.

4.3.1 Information request

The information request asked retailers to report their retail operating costs of supplying small retail customers in NSW. The information request asked for the fixed and variable components of the following categories of costs:

- call centre costs;
- customer information costs;
- corporate overhead costs;
- regulatory compliance costs;
- marketing costs; and
- billing and revenue collection costs.

The information request also asked for amounts of bad and doubtful debt for both regulated and contestable small retail customers. In addition, some retailers included other cost items in their reported operating costs. While the retailers provided some comments on their interpretation of each of the cost items included in operating expenditures, the comments do not permit a detailed analysis or comparison between retailers.

For each category, actual costs were requested for financial years from 2002/03 to 2005/06, and forecast costs were requested for financial years from 2006/07 to 2009/10. Costs are adjusted to 2006/07 dollars (where necessary) so that all estimates of ROC are also reported in 2006/07 dollars.

The information request also asked the standard retailers for actual small retail customer numbers for financial years from 2002/03 to 2005/06, and small retail customer numbers assumed for the purposes of forecasting costs for financial years from 2006/07 to 2009/10.

4.3.2 Estimating ROC

Retailers were asked to report their total retail costs of supplying small retail customers; both regulated retail customers and retail customers on negotiated contracts. These total costs can be used to estimate ROC by adding the fixed and variable components of each of the cost items reported by a retailer, and dividing by the retailers' small retail customers numbers. ROC is calculated in this way for each retailer and for each year between 2002/03 and 2009/10.

4.3.3 Reasonableness tests

These estimates of ROC are based entirely on the cost data provided by the retailers. While these cost data have not been audited, the data can nevertheless be tested for reasonableness.

Reasonableness test 1: Level of reported costs

The most obvious way of testing the reasonableness of the cost data provided by the retailers is to assess whether the ROC estimated using this data is consistent with estimates of ROC for other electricity retailers. The most useful source of this information is decisions by regulators. A number of relevant reports of ROC are discussed in Section 4.4.1. These external sources support the reasonableness of the retailers' reported operating costs.

Reasonableness test 2: Structure of reported costs

The cost data provided by retailers can be used to examine the structure of operating costs. Since the activities of different electricity retailers are similar, the structure of operating costs for different electricity retailers should also be broadly similar. Substantial differences in reported cost structures would raise questions about the reasonableness of the cost data provided. In particular, the contribution of the major cost items to total operating costs can be compared across retailers.

The comparison of cost structures across retailers is hampered by the fact that retailers are likely to allocate actual costs to the cost items identified in the information request in different ways. Nevertheless, a broad comparison across retailers is possible.

The four major cost items reported by retailers are corporate overheads, call centre costs, billing and revenue collection costs, and customer information costs. For each retailer and for each year from 2002/03 to 2009/10, the contribution of each of these cost items to total operating costs is calculated.

This indicates that the reported cost structures of the retailers are quite similar: the contribution of each of the major cost items is reasonably consistent across retailers. The clear exception is billing and revenue collection costs, for which there is a wide range across retailers. This wide range may be explained by different understandings of what is included in billing and revenue collection costs. In particular, the retailer at the low end of the range separately reported another cost item, which other retailers may have rolled into billing and revenue collection costs. If this is the case, the range for billing and revenue collection costs would be significantly narrower.

These results are also broadly consistent with CRA's estimate of the major electricity retail operating costs. CRA noted that the primary driver of retail operating costs are billing and revenue collection costs, which account for 40 per cent of total operating costs, followed by call centre costs, which account for 15 to 20 per cent of total operating costs, followed by corporate costs.[23]

Given this broad consistency in the structure of retailers' reported cost structures, these comparisons do not provide reason to conclude that the data provided by any of the retailers is inappropriate.

Reasonableness test 3: Forecast changes in operating costs

The retailers provided forecasts of operating costs over the period 2006/07 to 2009/10. These forecasts can be examined to determine whether the forecast increases in ROC are reasonable.

For each of the retailers, forecast changes in ROC over the period 2006/07 to 2009/10, including changes in the fixed and variable components of ROC, are calculated.

In order to better understand whether forecast increases in ROC are reasonable, it is useful to investigate what drives these increases.

First, consider the forecast increases in the fixed component of ROC. Each of the retailers is forecasting increases in the fixed component over the period 2006/07 to 2009/10. Changes in the fixed component of ROC can be attributed in part to changes in the fixed component of total operating costs, and in part to changes in customer numbers. Any increase in the fixed component of total operating costs, or any fall in customer numbers, will drive an increase in the fixed component of ROC. The separate impacts of these elements are assessed below.

For each of the retailers, forecast changes in the fixed component of total operating costs and forecast changes in customer numbers, over the period 2006/07 to 2009/10, are calculated. It is clear that forecast increases in the fixed component of total operating costs over the period 2006/07 to 2009/10 play an important role in driving increases in ROC over that period. However, it is unclear why the fixed component of total operating costs should increase in real terms over this period. In fact, there are at least two reasons to expect that the fixed component should fall:

- Over the four years to 2009/10, some fixed retail costs will become, at least to some extent, variable costs. The reason is that many of the investments made by retailers – in particular, investments in call centres and in customer

[23] CRA, *Inputs to the Development of Electricity Operating Costs and Net Margins for Domestic and Small Business Customers*, Report prepared for ORG, November 2001. Note that CRA excluded marketing costs from consideration. If marketing costs were included in CRA's examination of retail operating costs, as they are in this report, the percentage contributions of each cost item would be lower.

information systems – are relatively short-lived investments. As these investments are renewed, retailers have some ability to scale the size of these investments to expected customer numbers. With retailers forecasting falling customer numbers over the four years to 2009/10, this might lead to some reduction in fixed costs.[24]

- Improvements in productivity would be expected. These would particularly apply to cost items like billing and revenue collection and customer information costs, where improvements in IT systems would be expected to bring cost savings. Similarly, reductions in call centre costs might be expected.

Second, consider the forecast increases in the variable component of ROC reported by two retailers over the period from 2006/07 to 2009/10. As with the fixed component, changes in the variable component of ROC can be attributed in part to changes in the variable component of total operating costs and in part to changes in customer numbers. For each of the retailers, forecast changes in the variable component of total operating costs and forecast changes in customer numbers, over the period 2006/07 to 2009/10, are calculated.

It is clear that forecast increases in the variable component play an important role in driving increases in ROC. That the variable component of total operating costs should increase in real terms over the four years to 2009/10, while the retailers are expecting a decrease in customer numbers, is very unexpected. Since variable costs are those costs that are avoided by reducing output, it would be expected that the variable component would increase or decrease in line with changes in customer numbers, keeping variable ROC at a similar level. In contrast, retailers report that variable ROC will increase over the forecast period. We find it difficult to accept that this is reasonable.

In summary, the basis for several of the factors that drive forecast increases in ROC per customer up to 2009/10 is unclear:

- The fixed component of total operating costs increases in real terms over the period from 2006/07 to 2009/10, even though productivity improvements and the scaleability of investments in fixed retail costs suggest that the fixed component should fall.
- Even more surprisingly, the variable component of total operating costs increases in real terms over the period from 2006/07 to 2009/10, even though customer numbers fall.

A further concern that we have with the forecast costs is that the forecasts are based to a significant extent on actual operating costs in 2005/06. As a result, the actual ROC in 2005/06 may have an undue influence on the retailers' forecasts. While each retailers' forecasts of ROC over the period 2007/08 to 2009/10

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[24] Countering this are standard retailers' obligations as retailers of last resort. These obligations may reduce the ability of standard retailers to downsize systems to reflect any reduction in customer numbers. At the extreme, a standard retailer could have no customers, but would still be required to have systems in place to service all the customers in its geographic area. However, even in this circumstance we would not expect the fixed component of *total* ROC to increase over time. And, even if this is relevant to standard retailers, it is certainly not relevant to a MMNE.

follows a steadily increasing pattern from 2005/06, with little variability to 2009/10, there is significantly more variability observed in actual ROC for each retailer (over the period from 2002/03 to 2005/06). While this pattern is not unexpected, given the difficulties involved in forecasting costs, it does mean that if costs in 2005/06 were unusually high or low the forecasts will be adversely affected.

For these reasons, limited weight should be given to retailers' forecasts of operating costs, and any ROC derived from these forecasts.

4.3.4 Re-estimating ROC in light of these reasonableness tests

In order to address concerns regarding the reasonableness of retailers' forecasts of ROC over the period 2006/07 to 2009/10 – in particular, concerns about the rate of increase in costs over this period – we adopt the following approach:

- For each retailer, the fixed component of ROC over the period 2002/03 to 2005/06 is averaged. This provides an estimate of the efficient level of the fixed component of ROC.
- For each retailer, the variable component of ROC over the period 2002/03 to 2005/06 is averaged. This provides an estimate of the efficient level of the variable component of ROC.

Adding these estimates of the efficient fixed and variable components of ROC provides an estimate of the efficient level of ROC for each retailer over the forecast period. The range across retailers of ROC estimated in this way, including the range for the fixed and variable components of ROC per customer, is set out in Table 1.

	Range of fixed component	Range of variable component	Range of ROC
Average 2002/03 to 2005/06	46 to 66	17 to 22	63 to 82

Table 1: Re-estimated ROC ($/customer in 06/07 dollars)

4.3.5 Recommended range for MMNE ROC

We recommend that ROC be set between $60 and $80 per customer per annum, in 2006/07 dollars, for each year from 2007/08 to 2009/10.

This recommended range is derived substantially from data provided by the standard retailers. As discussed in Section 1, we interpret a MMNE to be an existing retailer with a large customer base outside NSW, such that the MMNE is able to use its existing systems to enter the mass market in NSW. Since the MMNE is a similar business to the standard retailers they are likely to have similar ROC. For this reason, the operating costs reported by the standard retailers and, in particular, the benchmarked ROC, is likely to provide an appropriate range for MMNE ROC. Notably, the standard retailers forecast falling customer numbers over the forecast period. This suggests that they will not achieve the fixed ROC estimated using the benchmarked approach because they will face falling customer numbers but constant fixed operating costs. A MMNE will not be likely to face this same stranding of fixed costs; as a new entrant, a MMNE can match its level of investment to its customer numbers.

4.4 BENCHMARKING RETAIL COSTS

Information on retail costs from other jurisdictions can provide useful information on the retail costs that a MMNE would face. The most useful source of this information is other regulatory decisions.

4.4.1 Benchmarking against regulatory audits

In some cases, regulators have reported the results of an assessment, or audit, of retail operating costs. Where such information is reported, it is broadly consistent with the recommended range for ROC.

In South Australia, ESCOSA undertook an audit of AGL SA's retail operating costs as part of its 2005 inquiry into electricity retail prices. While ESCOSA did not make public the results of this audit, ESCOSA did note that the results were consistent with its previous allowances for retail operating costs:

> "What the review of AGL SA's actual operating costs has shown is that the benchmark adopted in 2003 of $80 per consumer is similar to the cost estimated through the audit review. The accuracy of the cost allocation is not such as to justify a replacement of the benchmark number with the audit value."[25]

In the United Kingdom, Ofgem undertook a review of electricity retail operating costs in setting regulatory controls for Public Electricity Suppliers' prices to customers with a maximum demand of less than 100kW. As part of its review, Ofgem was provided with details of the operating costs that Public Electricity Suppliers incurred in supplying these customers. Table 2 sets out the reported operating costs per customer of these retailers.[26]

In Ireland, the Commission for Energy Regulation (CER) reviewed the tariffs that the Public Electricity Supplier (PES) in Ireland charges to customers that do not purchase from other suppliers in the market. In reviewing the operating costs of the PES, CER benchmarked these operating costs against a range of US and European energy companies. Data on the operating costs of these companies was collected using a consistent questionnaire developed by CER. The results of this benchmarking exercise are reported as operating costs per customer for each of the companies, as set out in CER's consultation paper.[27] The range of operating costs per customer across these benchmarked companies is

[25] ESCOSA, *Inquiry into Retail Electricity Price Path: Final Report*, March 2005, page 53.

[26] Ofgem, *Reviews of Public Electricity Suppliers 1998 to 2000, Supply Price Control Review: Initial Proposals*, October 1999.

[27] CER, *2006-2010 ESB Price Control Review – Public Electricity Supply: A Consultation Paper*, 26 July 2005. For further discussion of the benchmarking approach see: CER, *Direction to ESB PES (Public Electricity Supplier) on Allowable Costs 2006-2010 by the Commission of Energy Regulation*, 9 September 2005.

approximately €16 to €57 per customer, with a mean of approximately €41 per customer (in 2004 Euros). Converting these costs per customer into 2006/07 dollars, the range across the benchmark companies is approximately $29 to $105, with an average of approximately $76.

On balance, these estimates of operating costs per customer are not sufficiently different from the recommended range for ROC to suggest that the recommended range is inappropriate.

	1997/98		*1998/99*	
	£/customer	$/customer (2006/07 dollars)	£/customer	$/customer (2006/07 dollars)
Eastern	16.94	54	20.18	68
East Midland	15.87	50	19.85	67
London	25.34	80	26.50	89
Manweb	13.46	43	20.12	68
Midlands	21.65	68	23.55	79
Northern	26.39	83	30.03	101
NORWEB	14.37	45	26.77	90
SEEBOARD	18.82	59	24.23	82
Southern	18.01	57	19.56	66
SWALEC	18.06	57	25.90	87
South Western	14.37	45	18.71	63
Yorkshire	21.73	69	29.35	99
Scottish Power	20.68	65	26.18	88
Hydro Electric	45.32	143	51.99	175
Average	**20.79**	**66**	**25.92**	**87**

Table 2: Operating costs per customer in the UK

4.4.2 Benchmarking against regulatory allowances

The recommended ranges for operating costs can also be benchmarked against cost allowances by other regulators. Table 3 provides a summary of allowances for retail costs in recent regulatory decisions in Australia.

The allowances for retail costs in other regulatory decisions can be compared with the retail costs estimated using the bottom-up approach. In making this comparison, one of the difficulties is comparing costs on a consistent basis. In particular, other regulators have not *explicitly* included an allowance for CAC in retail costs. In fact, in most cases, it is generally unclear what costs are considered in the cost allowance.

Due to this uncertainty about the treatment of CAC, the benchmarked retail costs are compared with retail costs estimated using the bottom-up approach, both excluding CAC and including CAC. Figure 3 compares the benchmarked retail costs with the recommended range for ROC alone. Figure 4 compares the benchmarked retail costs with the combined recommended ranges for ROC and CAC. Figure 4 uses an average of the recommended ranges for residential CAC and business CAC, weighted by the total number of residential and business customers reported by the standard retailers. This weighted average gives an indication of the total allowed costs. In comparison, the recommended range for residential CAC slightly understates the allowed costs and the recommended range for business CAC significantly overstates the allowed costs.

Since other regulators have not explicitly included an allowance for CAC, the better comparison is likely to be that in Figure 3.

Decision	*Regulatory period*	*Retail cost per customer (nominal)*	*Retail cost per customer (2006/07 dollars)*	*Comments*
IPART (2000)	Jan 2001 *to* Jun 2004	$40 – $60	$48 – $72	IPART's cost allowance included an allowance for the costs of contestability. IPART recognised there are economies of scale in retailing, but noted that retailers reported similar costs per customer, irrespective of scale.
ORG (2001)	2002	$50 – $80	$58 – $93	ORG noted that the most significant cost components are likely to be billing and revenue collection costs and call centre costs. ORG's cost allowance included an allowance of $5 – $10 for the costs of FRC. ORG noted that the potential for larger NSW retailers to access economies of scale may justify a greater allowance for retail costs in Victoria than in NSW.
IPART (2001)	Aug 2002 *to* Jun 2004	$45 – $75	$54 – $90	IPART's cost allowance included an allowance for the costs of contestability.
SAIIR (2002)	2003	$80	$90	SAIIR's cost allowance included an allowance for the costs of FRC. SAIIR noted that AGL SA is larger than any of the Victorian retailers and larger in aggregate than any other electricity retailer. SAIIR suggested that AGL SA's costs should therefore be lower. AGL SA argued that since it was not a stapled retail/distribution business its costs would be higher.
ICRC (2003)	Jul 2003 *to* Jun 2006	$85	$95	ICRC's cost allowance included an allowance for the costs of FRC. ICRC considered that diseconomies of scale justified an increased allowance for retail costs relative to Victoria and South Australia.
OTTER (2003)	Jan 2004 *to* Dec 2006	$76.67	$86	OTTER's cost allowance did not include an allowance for the costs of FRC (as FRC had not been introduced in Tasmania). OTTER recognised the importance of economies of scale, but considered that a retailer in Tasmania should be able to achieve comparable costs to one in South Australia or the ACT.
CRA (2002)	2003	$90	$101	CRA's cost allowance was based on Victorian retailers' reports of their retail costs for standing offer customers, as reported to ORG during its 2001 investigation of retail pricing.

CRA (2003)	Jan 2004 *to* Dec 2007	$91	$101	CRA considered that its analysis from 2002 remained relevant, but adjusted this by CPI-1 (to allow for some productivity gain).
ESCOSA (2003)	2004	$82	$91	ESCOSA considered that its analysis from 2002 remained relevant, but increased the $80 allowance to reflect inflation.
IPART (2004)	Jul 2004 *to* Jun 2007	$70	$77	IPART based its allowance on estimates of retail operating costs provided by retailers. IPART noted that these estimates were lower than retail operating costs allowed for in other jurisdictions, but considered that the use of higher benchmark costs is inconsistent with determining efficient costs.
ESCOSA (2005)	Jan 2005 *to* Dec 2007	$84	$91	ESCOSA undertook a review of AGL SA's retail costs and concluded that the results of the cost audit were sufficiently similar to its previous benchmarking exercises that there was no justification for replacing the benchmarked results. ESCOSA increased the $82 allowance to reflect inflation.

Table 3: Electricity retail costs in other regulatory decisions

IPART, *Regulated Retail Prices for Electricity to 2004: Final Report*, December 2000.

ORG, *Special Investigation – Electricity Retailers' Proposed Price Increases: Final Report*, December 2001.

IPART, *Mid-term Review of Regulated Retail Prices for Electricity to 2004*, June 2002.

SAIIR, *Electricity Retail Price Justification: Final Report*, September 2002 and ESCOSA, *Inquiry into Electricity Standing Contract Prices: Final Report and Determination*, October 2002.

ICRC, *Investigation into Retail Prices for Non-Contestable Electricity Customers in the ACT: Final Determination*, May 2003.

OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania: Final Report and Proposed Maximum Prices*, September 2003.

CRA, *Electricity and Gas Standing Offers and Deemed Contracts (2003),* Submitted to the Department of Natural Resources and Environment, December 2002.

CRA, *Electricity and Gas Standing Offers and Deemed Contracts (2004-2007)*, Submitted to the Department of Infrastructure, December 2003.

ESCOSA, *2004 Electricity Standing Contract Price: Final Report*, December 2003.

IPART, *NSW Electricity Regulated Retail Tariffs 2004/05 to 2006/07: Final Report and Determination*, June 2004.

ESCOSA, *Inquiry into Retail Electricity Price Path: Final Report*, March 2005.

Mass market new entrant retail costs and retail margin

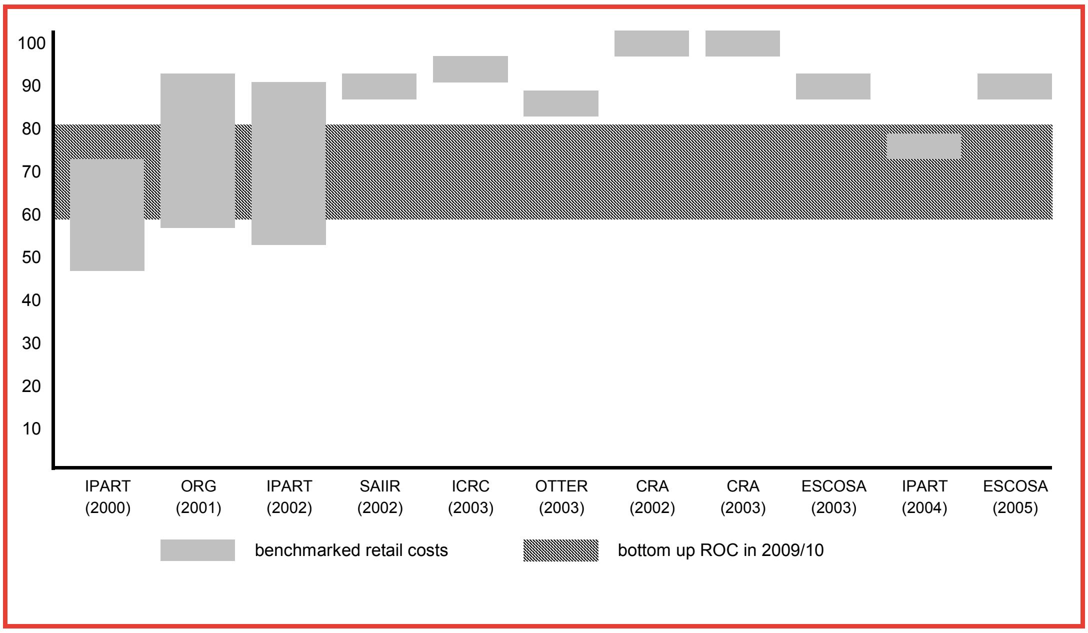

Figure 3: Benchmarked retail costs and recommended MMNE ROC (06/07 dollars)

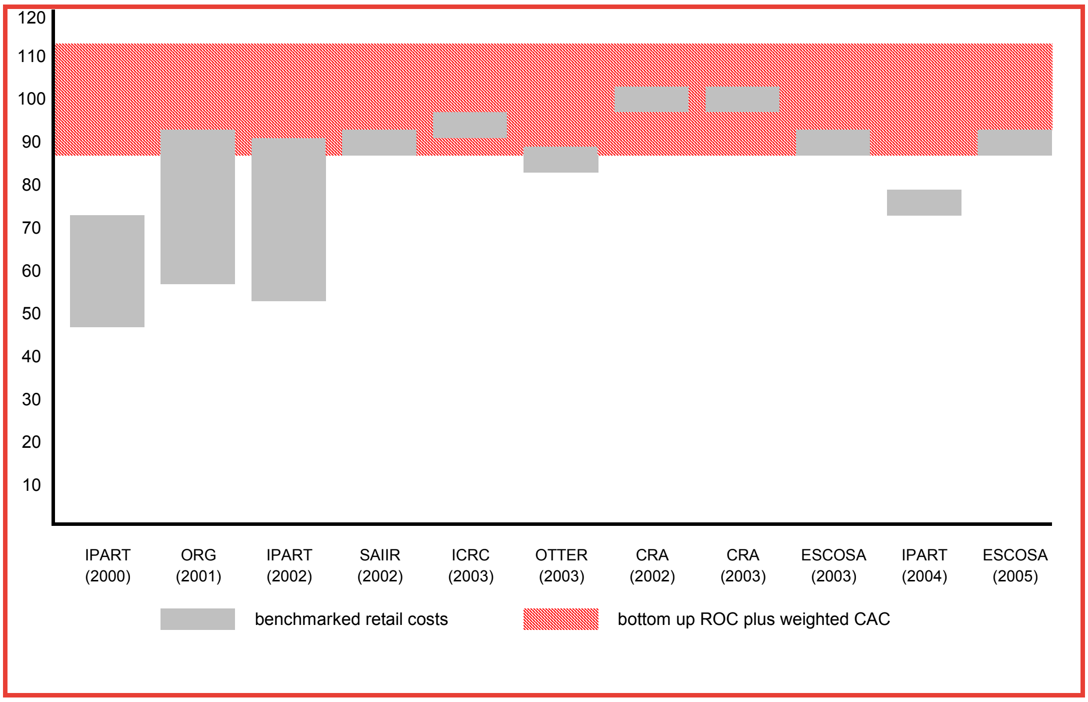

Figure 4: Benchmarked retail costs and recommended MMNE ROC plus weighted CAC (06/07 dollars)

4.5 CONCLUSION ON RETAIL COSTS

The results of the two approaches to estimating the retail costs of a MMNE – the bottom-up approach and benchmarking – are broadly consistent. Certainly, the results of the benchmarking approach are not so different from the results of the bottom-up approach to suggest that the results of the bottom-up approach should be amended. Consequently, the recommended ranges for retail costs for a MMNE are as follows:

- Between $85 and $110 per residential customer per annum, in 2006/07 dollars, for each year from 2007/08 to 2009/10.
- Between $100 and $125 per business customer per annum, in 2006/07 dollars, for each year from 2007/08 to 2009/10.

4.6 FIXED AND VARIABLE COMPONENTS OF RETAIL COSTS

The allowance for retail costs can be disaggregated into the fixed and variable components of costs.

The variable components of retail costs are to be reported as dollars per MWh. In order to convert the variable component of retail costs per customer into retail costs per MWh, it is necessary to determine average energy per customer. The standard retailers' forecasts of energy sales and customer numbers are used to do this.

The standard retailers' forecasts are used to determine average energy per customer for residential and business customers. Summing forecast energy sales and forecast customer numbers across the three standard retailers, for both residential and business customers, and dividing energy sales by customer numbers, provides the estimates of energy per customer over the period of the determination seen in Table 4.

	2007/08	*2008/09*	*2009/10*
Energy/customer (MWh)	9.59	9.86	10.03

Table 4: Energy per customer (residential and business customers)

4.6.1 Fixed and variable components of CAC

The costs of acquiring new customers are driven by customer numbers. The principal elements of CAC are the costs of contacting customers – either staff costs or commissions for door-to-door or telemarketing campaigns – and the costs of transferring customers. Each of these is driven by customer numbers. Therefore, CAC is reported as $/customer.

4.6.2 Fixed and variable components of ROC

The operating costs of supplying retail customers are a mix of fixed and variable costs. In their responses to the information request, retailers were asked to report the fixed and variable components of operating costs. For each retailer, and for each year from 2007/08 to 2009/10, the ratio of the fixed component of reported operating costs to total reported operating costs, and the ratio of the variable component of reported operating costs to total reported operating costs, is calculated. Considering only the retailers' responses to the information request, a clear consensus emerges: approximately 75 per cent of operating costs are fixed, and approximately 25 per cent of operating costs are variable.

It makes sense that retail operating costs are predominantly fixed. A large component of these costs are related to the systems that an efficient mass market retailer requires, including IT systems – such as billing and revenue collection systems and customer information systems – as well as customer service systems, including those required for the effective operation of call centres. The costs of establishing these systems are fixed costs. Once these systems are in place, the variable costs – which are primarily a function of processing customers bills, responding to customer queries, etc – are comparatively small.

Another way of looking at this is to consider the major elements of operating costs, as reported by the retailers. As discussed in Section 4.3.3 the four major elements of operating costs reported by the retailers are corporate overheads, billing and revenue collection costs, customer information systems and call centre costs. There is reason to think that each of these four costs elements is predominantly fixed. Corporate overheads, for instance, will not vary significantly with customer numbers. Billing and revenue collection costs and customer information system costs are both likely to consist predominantly of the IT systems required for the retailer to operate effectively. These are predominantly fixed. Finally, while call centre costs are likely to have a significant variable component, because the number of staff required in a call centre is largely dependent on the number of calls the centre receives, there is also likely to be a significant fixed component associated with the development of the systems necessary for the effective operation of a call centre.

While the standard retailers' reported data are relatively consistent, considered more broadly it is clear that views diverge. For instance, Integral Energy, in its public submission to IPART, reports that its retail costs are split relatively evenly between fixed costs and variable costs, with 47 per cent fixed and 53 per cent variable.[28] Some regulators are of the view that retail costs are predominantly fixed.[29] Other regulators are of the view that retail costs are predominantly

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[28] Integral Energy Submission, page 56.

[29] ESC, *Special Investigation: Review of the Effectiveness of Full Retail Competition for Electricity – Final Report*, September 2002, pages 42-43:

> "In relation to economies of scale, the presence of relatively high fixed costs, and declining per unit supply costs can result in the size of the market being only sufficient to accommodate a small number of suppliers operating at efficient scale.
>
> … economies of scale are likely to be achieved where wholesale purchasing, fixed costs associated with call centre operation, regulatory compliance costs, billing and marketing, can be spread across a larger number of customers."

variable.[30] The uncertainty is due, in part, to the nature of retail costs: in particular, as noted by the Tasmanian Energy Regulator, many of the costs associated with electricity retailing are not true variable costs: for instance, the costs of IT systems "tend to be incurred in relatively long flat steps" rather than varying directly with customer numbers.[31] Where this is the case, there is room for different understandings of whether these costs should be treated as fixed or variable.

Given the difficulties in interpreting the meaning of fixed and variable costs in the context of the operating costs of electricity retailers, the consensus that is apparent in the retailers' reported data should be given significant weight. For these reasons, we recommend that ROC are treated as 75 per cent fixed and 25 variable. The variable component of ROC should be converted to dollars per MWh using the estimate of energy per customer set out in Table 4.

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30 In setting regulatory controls for Public Electricity Suppliers' prices, Ofgem developed a cost allowance for retailers that was dominated by the variable component of costs. Ofgem, *Reviews of Public Electricity Suppliers 1998 to 2000 – Supply Price Control Review: Final Proposals*, December 1999.

31 OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania: Final Report and Proposed Maximum Prices*, September 2003, page 154.

5 MMNE retail margin

The retail margin represents the return that a MMNE requires in order to attract the capital needed to provide a retailing service. The retail margin that is required to attract capital will depend on the level of risk that a MMNE faces: the greater the risk, the greater the retail margin that is required in order that capital invested in the MMNE earns an appropriate return.

Of particular importance in estimating the retail margin is adopting a consistent approach to estimating retail margin, retail costs and energy costs. The expected returns approach to estimating the retail margin ensures that the recommended retail margin is linked to the recommended ranges for energy costs and retail costs.

5.1 METHODOLOGY

Three approaches are used to estimate the retail margin for a MMNE: the bottom-up approach, the expected returns approach and benchmarking.

The **bottom-up approach** estimates the return that a MMNE requires for each of the individual risks that it faces, and combines these individual components of the margin to determine a total retail margin. The **expected returns approach** estimates the expected cashflows that a MMNE will earn, and determines a retail margin that will ensure these expected cashflows compensate investors for the systematic risk of the cashflows.

Where necessary, these two approaches make use of data provided by the retailers in response to the information request (and the energy costs recommended for the standard retailers). This information is relevant to estimating the appropriate retail margin for a MMNE because the risks that existing retailers face in undertaking their retailing activities are likely to be very similar to the risks that a MMNE would face.

The **benchmarking approach** examines allowances for the electricity retail margin from regulatory decisions in other jurisdictions, and estimates an appropriate retail margin based on these comparisons. Allowances for retail margins in other jurisdictions are a useful proxy for the retail margin that is appropriate to a MMNE because retailers in other jurisdictions are likely to face similar risks to a MMNE.

5.2 BOTTOM-UP APPROACH

Integral Energy and their consultants, NERA, propose a bottom-up approach to the estimation of an appropriate retail margin.[32] The Integral/NERA approach involves identifying the general classes of costs and risks to be included in the retail margin, and estimating an allowance for each of these general costs or risks.

[32] *Integral Energy Submission*, Section 7. *NERA Retail Cost and Margin Report*, Section 6.

In this section, we first review the Integral/NERA approach, and adjust this approach so that it is consistent with the retail costs recommended in this report. We then use the asset base and the revenues attributable to small retail customers, as reported by each of the standard retailers, to estimate an appropriate margin.

5.2.1 The Integral/NERA approach

While we consider that the Integral/NERA approach has merit, some of the risks and costs that Integral/NERA propose to include in the margin are excluded from the margin under our approach. Integral/NERA propose to recover the following costs and risks through the margin:

- a return on customer acquisition costs;
- a return on working capital;
- a return on and of tangible assets excluding working capital; and
- compensation for asymmetric risks.

Integral/NERA develop allowances for each of these.

Integral/NERA estimate that it costs $524 per customer to acquire new customers. Amortising this amount over 10 years at a discount rate of 8 per cent results in a required return of $78 per customer per annum. Integral/NERA report that this represents 5.9 per cent of the average annual electricity bill for Integral Energy's customer base. Consequently, Integral/NERA propose that a return on customer acquisition costs should contribute 5.9 per cent to the retail margin.

Integral/NERA estimate an appropriate return on capital by considering the average lag between expenditures and revenues. Integral/NERA estimate that the average lag is one month, suggesting that working capital is about one month of retail revenue. At a WACC of 8 per cent, Integral/NERA propose that a return on working capital should contribute 0.7 per cent to the retail margin.

Integral/NERA assess the historic book value of Integral Energy's tangible retail assets, and apply a WACC of 8 per cent to this book value to calculate a required return on and of assets. Integral/NERA propose that a return on and of tangible assets should contribute 0.68 per cent and 0.79 per cent to the retail margin.

Integral/NERA note that it is difficult to estimate the costs of asymmetric risk. However, based partly on IPART's previous allowance for retail margin, Integral/NERA consider that compensation for asymmetric risk contributes 2 per cent to the retail margin. Integral/NERA consider this a conservative estimate.

Based on these conclusions, Integral/NERA propose a range for the retail margin, based on low, medium and high assumptions. The proposed range is summarised in Table 5. Integral/NERA propose that the best estimate of the appropriate retail margin for a MMNE is the medium case, implying a retail margin of 10 per cent.

Assumption / Contribution to margin	*Low*	*Medium*	*High*
Customer acquisition costs	300	524	700
WACC	6 %	8 %	10 %
Average customer life in years	7	10	13
Working capital	1 Month	1 Month	1 Month
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 %**

Table 5: Integral/NERA proposed retail margin

We have included an allowance for customer acquisition costs in the recommended allowance for retail costs, as set out in Section 4. These costs should not be recovered twice. Therefore, in order for the Integral/NERA approach to be consistent with the retail costs recommended in this report, the allowance for customer acquisition costs in the retail margin must be removed.[33]

Adopting the sensitivity analysis undertaken by Integral/NERA, but excluding customer acquisition costs, leads to a range for retail margin of between 2.8 per cent and 5.4 per cent, as set out in Table 6. The best estimate, as identified by Integral/NERA, is the medium estimate: 4.2 per cent.

[33] Integral/NERA recognise that this is a reasonable approach:

> "Whether to incorporate these additional costs [including customer acquisition 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…
>
> 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."

NERA *Retail Costs and Margin Report*, page 14.

Assumption / Contribution to margin	*Low*	*Medium*	*High*
WACC	6 %	8 %	10 %
Working capital	1 Month	1 Month	1 Month
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	**2.8 %**	**4.2 %**	**5.4 %**

Table 6: Integral/NERA proposed retail margin (excluding customer acquisition costs)

5.2.2 An alternative bottom-up estimate

An alternative bottom-up approach to estimating the appropriate retail margin is to assess a retailer's real EBITDA, as implied by the asset base and revenue attributable to small retail customers.

The information request asked each of the standard retailers to report the book value of assets attributable to small customers in NSW on regulated and negotiated customers. The information request asked for the actual book value of assets for each year from 2002/03 to 2005/06 and the forecast book value of assets for each year from 2006/07 to 2009/10.

The information request also asked each of the standard retailers to report their depreciation costs associated with supplying small retail customers in NSW. The information request asked for actual depreciation costs for each year from 2002/03 to 2005/06 and for forecast depreciation costs for each year from 2006/07 to 2009/10.

These data can be used to determine an amount for real EBITDA for each retailer. The process is as follows:

- The forecast total book value of assets attributable to small customers in NSW is calculated for each year by summing the value attributable to each of the classes of assets reported.
- This total book value of assets is converted into a nominal value, using an inflation rate of 3.2 per cent.
- The nominal return on capital (EBIT) is calculated by applying a nominal pre-tax discount rate of 11.5 per cent (which implies a real pre-tax discount rate of 8 per cent – consistent with the discount rate used elsewhere in this report) to the nominal book value of assets.
- The forecast total amount of depreciation associated with supplying small retail customers in NSW is calculated by summing the cost attributable to depreciation of each class of assets reported.

- This total amount of depreciation is converted into a nominal value, using an inflation rate of 3.2 per cent.
- The nominal EBITDA is calculated by summing the nominal EBIT and the nominal amount of depreciation.
- The nominal EBITDA is converted to a real EBITDA using an inflation rate of 3.2 per cent.

Repeating this process for each year of the period of the determination provides an estimate for EBITDA for each of 2007/08, 2008/09 and 2009/10. Averaging these values provides an estimate of the amount of real EBITDA that each retailer requires.

An estimate of the appropriate margin for each retailer can be determined by dividing the estimate of the amount of real EBITDA that each retailer requires by that retailer's revenue. Each of the retailers reported forecast revenue from small retail customers on regulated and negotiated tariffs for 2006/07. Dividing each retailer's estimated amount of real EBITDA by their forecast revenue for 2006/07 provides an estimate of the appropriate margin of between 4.1 per cent and 4.8 per cent.

5.3 EXPECTED RETURNS APPROACH

In this section we present an estimate of the retail margin derived from the systematic risk of returns to equity holders. Underlying this estimate is the linear relationship between expected returns on investment and the systematic risk of those returns, also referred to as market risk or non-diversifiable risk. The relationship between required returns and systematic risk is generally accepted amongst Australian regulators and is standard corporate finance practice. We first present the framework that underlies our estimated retail margin, followed by an application to the hypothetical MMNE. We rely on data from listed electricity utilities in Australia, the United Kingdom and the United States, as well as data supplied by Integral Energy, EnergyAustralia and Country Energy.

5.3.1 Introduction

In most instances of price-setting for regulated entities, the regulator estimates the earnings that it considers equivalent to the return on investment that would prevail in a competitive market. This level of normal earnings is the product of the regulated asset base and an estimate of the regulated entity's cost of capital. However, for retail electricity firms, regulators typically estimate an appropriate retail margin, because a significant portion of firm value is derived from intangible assets – the customer base – from which it is difficult to determine the regulated asset base.

One possibility is to estimate this intangible part of the asset base as total customer acquisition costs, an approach recommended by Integral Energy. This is not entirely dissimilar to the standard estimation technique of Depreciated Optimised Replacement Cost (DORC), typically used in relation to energy network businesses and transport infrastructure. Integral Energy has performed an estimate of the cost of acquiring a customer base, a cost that theoretically could be incurred via acquisition from a competitor, and an estimate of the rate at which this asset depreciates.

In this section, we perform an estimate of the appropriate margin that is implemented even without any knowledge of the cost of acquiring or developing the asset base. Our task is to estimate the retail margin that is sufficient to earn a normal return on an asset base of customers, even though we have no prior market value of that asset base. We discuss our method for estimating this margin with the aid of a simple example, as set out in Appendix A, to which we add additional layers of complexity as we approach the actual situation faced by a MMNE.

5.3.2 Risk Decomposition

A MMNE will face a number of risks and one of the roles of the retail margin is to provide appropriate compensation to the firm (and ultimately its investors) for bearing this risk. However, not all of the risks facing a MMNE will be relevant to the retail margin – some will be accommodated elsewhere. The remainder of this section catalogues some of the risks facing a MMNE and develops the links between risk and retail margin.

Energy Purchase Risk

One risk facing a MMNE is the uncertainty surrounding the cost of purchasing energy. This risk has two components.

First, there is uncertainty about the level of future energy prices. This is reflected in Frontier's report on energy costs, which uses a range of energy price scenarios for the purpose of estimating the market price of energy. These different scenarios provide different estimates of energy costs. This is an estimation risk, which has no systematic component and consequently has no relevance to retail margin. That is, this risk is not about whether future prices will be above or below expectations, but about the ability to properly process the presently available data.

Second, for any energy price scenario, there still remains some price variability – a standard deviation around the expected price (as measured on the horizontal axis of the efficient frontiers). This variability has a non-systematic component (in the short-term price variability is driven by weather and unplanned outages) and a systematic component (in the longer term there is a weak relationship between prices and general economic conditions). It is only the latter, systematic, component that requires compensation via a return in the form of a retail margin. However, the high degree of hedging that electricity retailers are likely to engage in, and the relatively weak relationship between prices and aggregate economic conditions, means that this risk has a small impact on retail margins, relative to the uncertainty about volume discussed below.

Volume Risk

Another risk facing a MMNE is the uncertainty surrounding volumes. This risk also has two components.

First, volumes might be higher or lower than expected. As for prices, this variability has a non-systematic component (in the short-term volume variability is driven by weather and unplanned outages) and a systematic component (in the longer term there is a relationship between volumes and general economic conditions). It is only the latter, systematic, component that requires compensation via a return in the form of a retail margin. We quantify the relationship between volume growth and economic conditions via a regression analysis in Section 5.3.4.

Second, there is a form of volume risk in sizing the hedge that reflects a retailer's contracting strategy. Most hedge contracts are for fixed volumes, but the retailer does not know exactly what future energy volume will be and, therefore, what volume will need to be hedged. This is not an issue under the ETEF, where all volume, whether it turns out to be higher or lower than expected, is essentially hedged. That the size of the required hedge is not known with certainty contributes to what may also be referred to as a volume risk. This in turn impacts the variability of prices around the expected price. That is, one reason the overall energy purchase price is not known with certainty is that the size of the hedging activity cannot perfectly match realized volumes. Consequently, the impact of this risk is captured in price variability discussed above.

5.3.3 Retail margin as compensation for bearing systematic risk

The basic premise underlying the estimate of an appropriate retail margin is that the expected returns to equity holders should reflect the systematic risk of those returns. This premise is the basis for the setting of almost every regulated price in Australia. Systematic risk is the result of exposure to overall economic or market conditions. Non-systematic risk is the variability in the returns to equity holders resulting from factors uncorrelated with overall economic conditions. Non-systematic risk is also referred to as diversifiable or firm-specific risk. The relationship between systematic risk and expected returns to equity holders is formalised in the Capital Asset Pricing Model (CAPM) presented below:

$$r_e = r_f + \beta_e \times (r_m - r_f)$$

where:

r_e = the expected returns to equity holders;
r_f = the risk-free rate of interest;
r_m = the expected return on the market portfolio of all risky assets; and
β_e = the equity beta, a measure of the systematic risk of returns to equity holders.

The equity beta is a measure of the association between returns to equity holders and returns on the market portfolio. Expressed as an equation, the equity beta is:

$$\beta_e = \frac{COV(r_e, r_m)}{\sigma_m^2}$$

where:

$COV\ (r_e, r_m)$ = the covariance of returns to equity holders and returns on the market portfolio of all risky assets; and
σ_m^2 = the variance of returns on the market portfolio.

The systematic risk of returns to equity holders increases with financial and operating leverage. Financial leverage is the proportion of capital contributed by debt holders, who receive fixed cash flows rather than the variable cash flows (dividends) received by equity holders. The more cash flows directed to debt holders in the form of fixed interest payments, the more volatile are the residual cash flows available to pay dividends to equity holders. The same reasoning applies in relation to the impact of operating leverage on the risk faced by equity holders. The higher the proportion of fixed costs in the entity's cost structure, the more volatile will be the residual cash flows (operating profits) available to make distributions to debt and equity holders.

Financial and operating leverage impact directly on the appropriate retail margin for a MMNE. The retail margin must be sufficient to provide reasonable compensation for the potential variation of earnings in response to various economic conditions. It is positively related to: (a) the variability of revenue in association with economic circumstances; (b) operating leverage – the proportion of fixed costs in the entity's cost structure; and (c) financial leverage – the proportion of the capital base financed by debt holders.[34]

A detailed example is presented in Appendix A for the purposes of illustrating the approach.

5.3.4 Assumptions relative to a MMNE

As illustrated in the example estimation set out in Appendix A, the appropriate margin for a MMNE is a function of five assumptions:

- the systematic risk of returns as measured by asset beta;
- operation leverage as measured by the proportion of costs which increase at a constant rate with changes in volume;
- percentage change in volume in response to economic conditions;
- variance in market returns; and
- asset life.

In this section, we estimate a range for the margin for a MMNE, as a function of these five value drivers.

Systematic risk, financial leverage and expected returns

The systematic risk of returns to equity holders is directly related to the assumed financial leverage. We have jointly estimated an equity beta based upon

[34] Further explanation of these components of systematic risk can be found in standard corporate finance textbooks. See, for example, Brealey, R.A., S. C. Myers and F. Allen, (2006), *Principles of Corporate Finance*, 8th ed, McGraw-Hill, Chapter 9, and Damodaran, A., (2001), *Corporate Finance Theory and Practice*, 2nd ed., Wiley.

comparable firm analysis of listed energy utilities in Australia, the United States and the United Kingdom.

Operating leverage

As the proportion of fixed costs in the entity's cost structure increases, so does the volatility of its returns. For the purposes of estimating the margin for a MMNE, we require an estimate of operating leverage, computed as the proportion of expenses which are fixed versus variable. In estimating this operating leverage, we consider how expenses would increase or decrease in response to electricity demand which is above or below expectations. Therefore, we use the term *volume-related costs* in this section, in contrast to the term *variable costs* which was used in prior sections to refer to expenses relating to customer numbers.

We estimate volume-related costs within the range of 70 – 80 per cent, implying that costs unrelated to volume lie within the range of 20 – 30 per cent. Table 7 details how we arrived at this range. We estimate the volume-related costs for an electricity retailer with 900,000 customers and expected annual sales volume of 5 million MWh over the next three forecast years.

According to this base case estimation, the proportion of volume-related costs is 79 per cent. This occurs because the largest components of the firm's costs are energy purchase costs and network fees, which are predominantly volume-related. The remaining costs – operating costs, customer acquisition costs, depreciation and amortisation, and NEM fees – are largely independent of annual volume. The treatment of customer acquisition costs illustrates the difference between volume-related costs and customer related costs. The cost of acquiring customers is expected to increase directly with the number of customers, but is largely independent of the volume purchased by those customers in any given year. Hence, customer-acquisition costs are considered non-volume related. On the other hand, energy purchase costs increase directly with total volume while network charges are partly volume-related and partly independent of volume.

Our estimated range for the proportion of volume-related costs is 70 – 80 per cent compared to the base case estimate of 79 per cent. This occurs because the base case estimate is more likely to overstate the proportion of volume-related costs, rather than under-estimate this proportion. Our base case estimate assumes that 25 per cent of operating costs are volume-related, the same proportion assumed to be customer-related. However, it is likely that a reasonable proportion of these operating costs could be independent of volume. If all operating costs are considered non volume-related, the proportion of volume-related costs falls to 77 per cent. Furthermore, all energy purchase costs and 81 per cent of network fees are assumed to be volume-related, which leaves no scope for estimation error on the upside, but some scope for estimation error on the downside.

	Non volume-related	Volume-related	Total	Volume-related (%)	Proportion (%)
$m:					
Energy purchase	0	262	262	100	32
Network fees	84	371	455	81	56
Operating	47	16	63	25	8
Customer acquisition	28	0	28	0	3
Depreciation	8	0	8	0	1
Total	168	649	816	79	100
$/MWh:					
Energy purchase	0	52	52		
Network fees	17	74	91		
Operating	9	3	13		
Customer acquisition	6	0	6		
Depreciation	2	0	2		
Total	34	130	163		
$/customer:					
Energy purchase	0	291	291		
Network fees	94	412	506		
Operating	53	18	70		
Customer acquisition	31	0	31		
Depreciation	9	0	9		
Total	186	721	907		

Table 7: Estimation of the proportion of volume-related costs for an electricity retailer with expected annual volume of 5 million MWh and 900,000 customers

Percentage change in volume in response to market conditions

We use a range of 1.5 – 2.5 per cent as the assumption for a one standard deviation change in volume growth from the expected level. From 1960/61 – 2004/05, the annual standard deviation of changes in electricity volume growth was 3.3 per cent. For the same period, 24 per cent of the volatility of electricity consumption growth can be explained by changes in Australian GDP. The coefficient from this regression is 0.86 and the standard deviation of GDP growth is 1.9 per cent. The coefficient from the regression of volume growth on GDP growth is insignificantly different from one, so we assume a one-for-one relationship between GDP growth and volume growth. Hence, a one standard deviation shift in GDP growth – assumed to be 2 per cent – implies a one standard deviation shift in volume growth of the same magnitude.

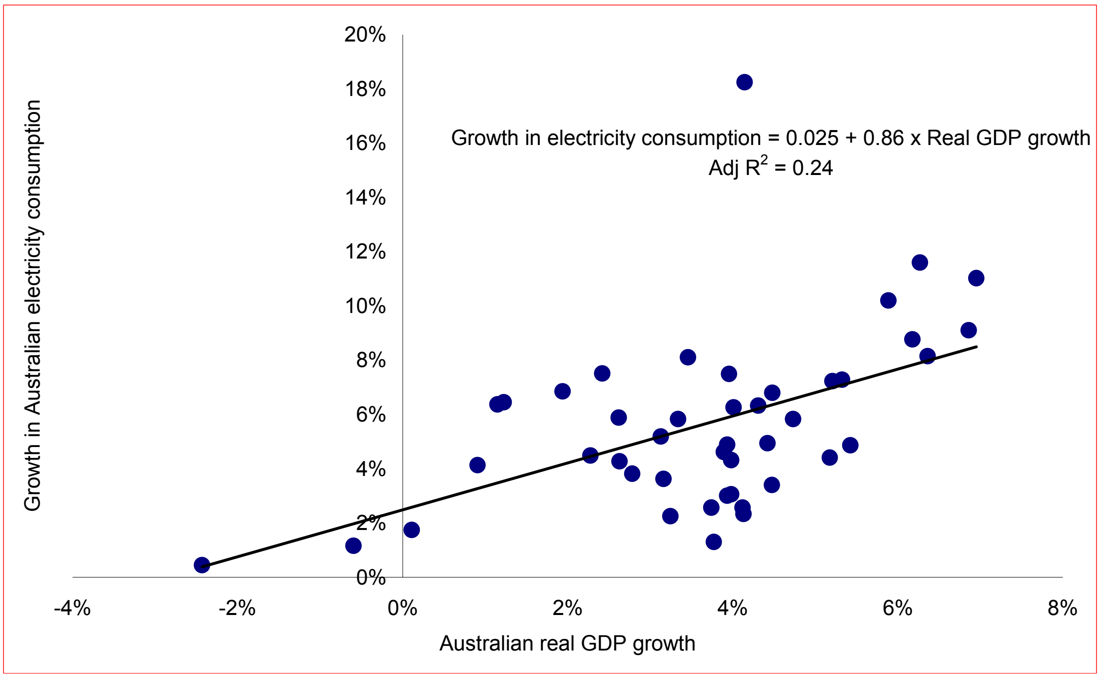

Figure 5: Relationship between growth in electricity consumption and real GDP growth

Volatility of market returns

We estimate the standard deviation of equity market returns within a range of 10 – 20 per cent. The volatility of Australian equity returns from 1885 to 2006 was 17 per cent and the mean annual return was 7.3 per cent. The mid-point of our range is 15 per cent.

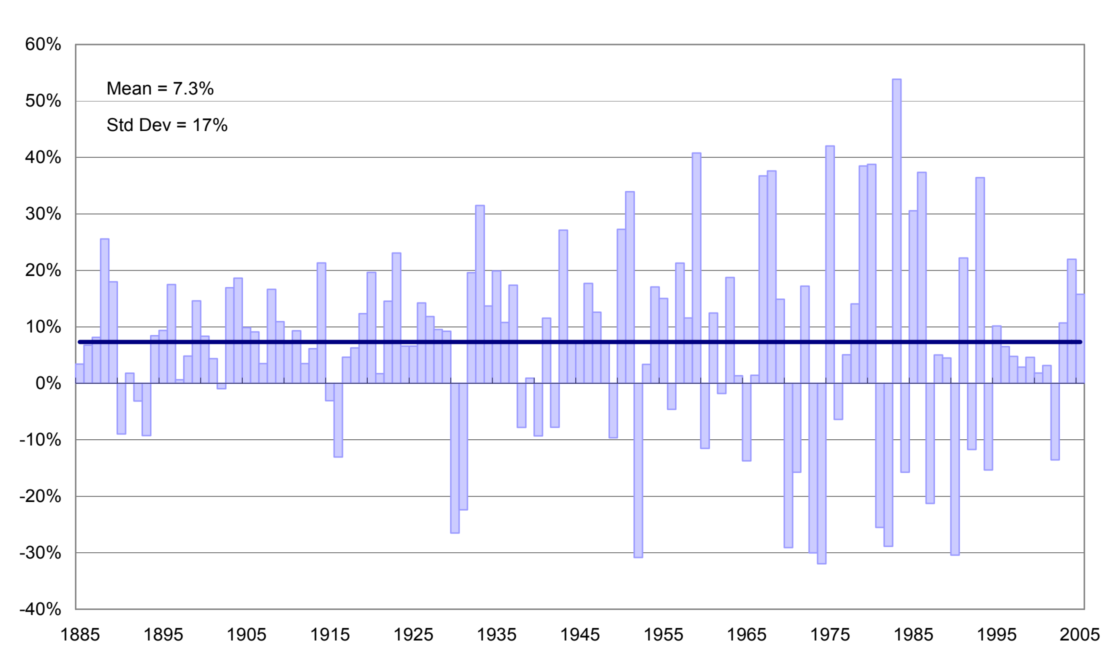

Figure 6: Australian equity returns less 10-year Government bond yield, 1885 – 2005

Modelling details

Our modelling assumes an explicit forecast period of 10 years followed by the assumption that expected cash flows remain at the same level in perpetuity. We assume a real pre-tax discount rate of 8 per cent, as is the case with our analysis throughout.

Expected annual growth in electricity consumption is 2 per cent, consistent with the projections of NEMMCO as shown in Table 8. These projections also show high and low case outcomes that have cumulative average growth rates of 1.0 and 3.3 per cent, but these do not include the probabilities of occurrence. We assume a one-for-one relationship between volume growth related to economic events and GDP growth, and that economic growth could be 1.5 – 2.5 per cent better or worse than expected. The volatility of volume growth will exceed this level, but we need to isolate the variation in volume growth attributable to economic conditions. Our assumptions are broadly consistent with the range presented by NEMMCO.

Year-ending	Medium	High	Low
30/06/2004 actual	171,694		
30/06/2005 actual	175,374		
30/06/2006 estimate	188,818		
30/06/2007	193,013	195,990	190,242
30/06/2008	197,253	202,330	192,791
30/06/2009	200,786	208,436	194,587
30/06/2010	203,739	214,005	195,443
30/06/2011	207,033	223,481	196,915
30/06/2012	210,945	230,256	198,920
30/06/2013	215,491	237,799	201,510
30/06/2014	219,646	245,089	203,486
30/06/2015	224,183	253,305	205,678
30/06/2016	228,895	261,292	207,967

Table 8: NEM-wide scheduled energy projections (GWh)

In contrast to the assumption that volume growth varies to some degree with GDP growth, expected volume growth for the MMNE is zero from its base level. NEMMCO anticipates annual volume growth for the entire market of 2 per cent, but this does not necessarily equate to anticipated volume growth for a MMNE. Volume growth for that specific firm will be a function of both volume growth in the entire market and changes in market share. If the MMNE comes into existence by acquiring an incumbent firm and the market shares of remaining retailers remain constant, anticipated annual volume growth would be around 2.0 per cent. Alternatively, if the MMNE gradually acquires market share from competitors, customer numbers would start below the 900,000 assumed for the representative firm, but would grow at an above-average rate. Given this uncertainty over industry structure, we consider the most appropriate assumption to be that the representative firm is approximately the size of incumbent retailers both in terms of customer numbers and volumes, but we assume zero trend growth in volume. However, we are assuming that the MMNE incurs sufficient customer acquisition costs each year to retain its customer base and that real prices are steady. These joint assumptions – zero trend volume growth and constant real prices – imply nominal revenue growth equal to inflation.

5.3.5 Results

In this section we present estimated retail margins under several alternative definitions of the retail margin. For comparison purposes, it is imperative that the term *margin* is used on a like-for-like basis by explicitly defining which cost elements are included or excluded from the computation. The definitions we use are presented with our results in Table 9.

We have estimated the required margins relative to revenue that provides sufficient compensation for the systematic risk of an investment in a MMNE retailer. The results rely on cost estimates for energy costs, retail costs and network costs. For energy costs and retail costs, we use the results from our analysis of energy costs and retail costs as inputs into our analysis of the retail margin. The results also rely upon the assumptions that:

- volume-related operating costs lie within a range of 20 – 30 per cent;
- the standard deviation of annual equity market returns lies within a range of 10 – 20 per cent;
- the real pre-tax cost of capital lies within a range of 6.8 – 9.4 per cent; and
- the standard deviation of annual GDP growth is 1.5 – 2.5 per cent.

Margin analysis

A base-case estimate for the required margin is computed using the mid-point of the various assumptions discussed above. Similarly, a range for the required margin *could* be estimated with reference to the extreme (maximum and minimum) assumptions. However, this approach would result in a wide and relatively meaningless margin range. That is, the probability that all assumptions are at the extreme end of their reasonable range is small. For this reason, our margin analysis considered 81 potential scenarios – each assumption outlined at the end of the previous section was assumed to take one of three values: high-point, mid-point and low-point.[35] This resulted in a potential distribution for the required margin that incorporates uncertainty in the key assumptions. Our approach is to assume a reasonable range that incorporates the middle third of the 81 potential outcomes. In other words, the low and high results reported in Table 9 reflect the 33.3 and 66.7 percentiles respectively.

Table 9 reports the required margin for a variety of earnings definitions. Focusing on the EBITDA margin, the required margin as a proportion of sales is within a reasonable range of 4.4 – 6.4 per cent.

These EBITDA margins correspond to a value of the assumed MMNE of:

- $536 million (within a reasonable range of $430 to $723 million); and
- $595 per customer (within a reasonable range of $477 to $803) per customer.

[35] With three different states and four variables, the number of scenarios is $3^4 = 81$.

	Low	Base	High
Price ($/MWh)	170	171	173
EBIT margin = Revenue minus all costs (energy, network, operating, customer acquisition, NEM fees and depreciation):			
% sales	3.5%	4.3%	5.5%
$m	29	36	47
$/MWh	5.87	7.30	9.50
$/Customer	33	40	53
EBITDA margin = Revenue minus all costs except depreciation (energy, network, operating, customer acquisition, NEM fees):			
% sales	4.4%	5.2%	6.4%
$m	37	44	55
$/MWh	7.48	8.91	11.11
$/Customer	42	49	62
Net margin = Revenue minus energy costs, network costs, and operating costs:			
% sales	7.7%	8.5%	9.7%
$m	65	72	83
$/MWh	13.07	14.51	16.71
$/Customer	73	80	93
Gross margin = Revenue minus energy costs and network costs:			
% sales	15.2%	15.9%	17.0%
$m	128	135	146
$/MWh	25.67	27.11	29.31
$/Customer	143	150	163
Valuation metrics assuming zero expected volume growth:			
Value ($m)	430	536	723
Value ($/Customer)	477	595	803
Book-to-market assets ratio	0.55	0.74	0.92
Book-to-market equity ratio	0.33	0.60	0.88

Table 9: Margins and valuation metrics

Comparison to Integral/NERA submission

Importantly, when benchmarking the results against prior regulatory decisions and market data, margins must be compared using the same definition. In Table 9 we report margins under four alternative definitions. Integral/NERA submit that a margin of 7 – 13 per cent is appropriate, where this margin was compensation for customer acquisition costs (4.1 – 7.5 per cent), return on tangible assets and working capital (1.8 – 2.4 per cent) and asymmetric risks (1 – 3 per cent). This margin concept is analogous to our estimated net margin of 7.7

– 9.7 per cent. Hence, the upper bound of our estimated reasonable range is consistent with the mid-point of Integral/NERA's submission.

To directly compare the submission made by Integral/NERA with our estimates, we prepare a common size income statement, presented below. We estimate revenue and each line of the income statement on the basis of $/MWh and as a percentage of revenue. We assume the energy cost, network fees and operating costs for the MMNE. We have not used Integral/NERA's submission in relation to these costs because we want to focus the analysis only on its submission in relation to margin. In other words, we ask the question, "For a representative firm with our assumed cost structure and size, what are the margins which would prevail under our estimation and Integral/NERA's submission?"

	Frontier analysis	*Frontier analysis using Integral/NERA submission*
% of sales		
Revenue	100.0	100.0
Energy and network costs	84.1	82.7
Gross margin	15.9	17.3
Operating costs	7.4	7.3
Net margin	8.5	10.1
Customer acquisition costs	3.3	5.9
EBITDA margin	5.2	4.2
Depreciation	0.9	0.8
EBIT margin	4.3	3.4
$/MWh		
Revenue	***171***	***174***
Energy and network costs	143	143
Gross margin	27	30
Operating costs	13	13
Net margin	14	17
Customer acquisition costs	6	10
EBITDA margin	9	7
Depreciation	2	1
EBIT margin	7	6

Table 10: Common size income statement for the representative firm

The first thing to note is that the required price is slightly higher under the Integral/NERA submission, although the difference is small. A price of $174/MWh is required under Integral/NERA's proposed margins, given

Integral/NERA's proposed customer acquisition allowance and return on assets computations and our assumed operating, energy and network costs. This is 2 per cent higher than our implied price of $171/MWh.

Integral/NERA's proposed allowance for customer acquisition costs is considerably higher than our proposed allowance. This stems from Integral/NERA's estimated customer acquisition costs of $524 per customer, compared to our estimated acquisition costs of around $200 per customer. The respective allowances of $10/MWh versus $6/MWh are both derived from amortisation of these acquisition costs over the average life of the customer. In percentage terms, Integral/NERA proposed that the allowance for customer acquisition costs should be around 6 per cent of revenue, compared to our estimate of 3 per cent. In contrast, our estimates provide for greater depreciation and return on capital allowances than proposed by Integral/NERA, but these are not sufficient to offset our lower allowance for customer acquisition costs.

In sum, our estimated net margin of 8.5 per cent can be directly contrasted with Integral/NERA's proposed net margin of 10 per cent. However, it falls within Integral/NERA's submitted range of 7 – 13 per cent. Importantly, because we include customer acquisition costs as a line item in retail costs, either of these net margins would involve double-counting of customer acquisition costs.

Reasonableness checks: Comparison with market prices

We performed a number of reasonableness checks by comparing our estimated valuation metrics with what we observe in the market-place. This analysis suggests that the valuation implied by our estimated margins is reasonable:

- The value per customer range of $477 – $803 (with a base-case estimate of $595) is broadly consistent with Integral/NERA's submission of $524 per customer.
- The book-to-market equity value base-case estimate of 0.60 is consistent with listed comparables. The mean book-to-market equity value for 89 US-listed utilities at 31 December 2005 was 0.57 with a standard deviation of 0.19. This implies a 90 per cent confidence interval for the mean book-to-market equity ratio of 0.54 – 0.61.
- The book-to-market equity value estimate is higher than listed retailers (all retailers, not energy focussed retailers). The mean book-to-market equity for 206 US-listed retailers at 31 December 2005 was 0.43, with a 90 per cent confidence interval of 0.40 – 0.46. The fact that our base-case estimate has a higher book-to-market value compared to general retailers is intuitively correct. The book-to-market equity ratio is inversely related to growth expectations and the broader class of retailers is expected to grow at a faster rate than an electricity retailer.

- The after-tax return on capital is 6.4 per cent, which is consistent with the mean after-tax return on capital for 89 US-listed utilities of 6.7 per cent in 2005 (within a 90 per cent confidence interval of 6.2 – 7.3 per cent).[36]

5.3.6 Conclusion on expected returns approach

The expected returns approach to estimating retail margins is a process of setting the electricity price at a level where the systematic risk of returns is equal to the systematic risk which would be expected to prevail in a competitive market. This is the basic premise underlying the setting of almost every regulated price in Australia. Using this approach, we estimate that an EBITDA margin of 4.4 – 6.4 per cent is appropriate. This is consistent with an assumption that a retail electricity firm has systematic risk equivalent to that of a typical listed firm.

5.4 BENCHMARKING RETAIL MARGIN

The most common regulatory approach to determining an appropriate retail margin for inclusion in regulated retail electricity tariffs is to benchmark the retail margin against other regulatory decisions. Typically, regulators will consider the risks to which retailers are exposed in other jurisdictions, either giving greater weight to decisions from jurisdictions in which retailers face similar risks, or adjusting the retail margin adopted in other jurisdictions to reflect differences in risks.

While there is undoubted circularity with this approach, benchmarking can nevertheless provide useful information about the reasonableness of the retail margin estimated using the bottom-up approach and the expected returns approach.

Table 11 provides an overview of retail margins included in recent regulatory decisions, as well as a summary of the risks for which the margin is intended to compensate retailers. This overview suggests that the allowance for the retail margin should be in the range 1.5 per cent to 8 per cent (or 1.5 per cent to 5 per cent if CRA's reports to Victoria's Department of Infrastructure are excluded from the benchmark group).

A key issue in benchmarking is to use benchmarks that are as closely comparable as possible. Most important in this regard is that the margin is understood in the same terms. While the margin is often not clearly defined, the consensus in these regulatory decisions seems to be that the relevant definition is net margin; that is, margin on sales before interest and tax but after all other costs.[37]

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36 After-tax return on capital is approximately EBIT x (1 – tax rate)/(Debt + Book value of equity). Our representative firm has assets of $396 million (900,000 customers with book value of assets per customer of $440). The estimated EBIT reported above is $36 million, which is $25 million after 30 per cent tax.

37 See for example: CRA, *Electricity and Gas Standing Offers and Deemed Contracts (2003)*, Submitted to the Department of Natural Resources and Environment, December 2002, page 27; IPART, *Review of Gas and Electricity Regulated Retail Tariffs: Issues Paper*, October 2003, page 10.

There are two other key issues to consider. First is the treatment of depreciation. Depreciation could be included as a line item in retail costs, or as a component of the retail margin. We have chosen the former approach. While it is often unclear, it appears that most regulators, with the exception of ESCOSA, have chosen the former approach. This suggests that the EBIT margin from Table 9 is the better comparator with the regulatory benchmarks. Second is the degree of risk to which retailers are exposed. In particular, many of the regulators have noted the importance of protection from energy purchase risk (through schemes such as ETEF) and the importance of using appropriate benchmarks. With ETEF rolling off, this suggests that the determinations from Victoria and South Australia should be given greater weight.

Decision	*Regulatory period*	*Margin*	*Comments*
IPART (2000)	Jan 2001 *to* Jun 2004	1.5 – 2.5 %	IPART noted that retailers are protected from energy purchase risk by the ETEF.
ORG (2001)	2002	2.5 – 5 %	ORG considered that the activities of electricity retailers are generally considered low risk. ORG recommended a higher margin than adopted by IPART because: NSW retailers are protected from energy purchase risk by ETEF; and NSW retailers are government-owned enterprises with a lower cost of capital.
IPART (2002)	Aug 2002 *to* Jun 2004	1.5 – 2.5 %	IPART considered that the retail margin should reflect the risk associated with energy purchasing costs, customer default and bad debt, and competition from electricity substitutes. IPART considered that higher retail margins in Victoria are not an appropriate benchmark, because standard retailers in NSW are protected from energy purchase risk by the ETEF.
SAIIR (2002)	2003	5 %	SAIIR considered that Victoria is a better benchmark than NSW, because standard retailers in NSW are protected from energy purchase risk by the ETEF. SAIIR considered that a retail margin from the upper end of Victoria's benchmark range was not unreasonable, given the risks of operating in the peaky South Australian market.
ICRC (2003)	Jul 2003 *to* Jun 2006	3 %	ICRC considered that the standard retailer in the ACT did not face the same risks as the standard retailer in South Australia. ICRC therefore allowed a lower retail margin than SAIIR.
OTTER (2003)	Jan 2004 *to* Dec 2006	3 %	OTTER considered that the standard retailer in Tasmania faced minimal energy purchase risk (due to the operation of a vesting contract) and minimal contestability risk. The retail margin included an allowance for bad debt, working capital and profit.
CRA (2002)	2003	5 – 8%	CRA considered that a retail margin in excess of that provided by the ORG for 2002 would promote more effective competition and enable more customers to benefit from competition.
CRA (2003)	Jan 2004 *to* Dec 2007	5 – 8 %	CRA considered that the retail margin should reflect any energy purchase risk that was not accounted for in estimates of energy costs, and that the retail margin should also facilitate the emergence of competition. CRA considered that it was reasonable to increase the retail margin during the regulatory period, to account for increasing uncertainty over forward estimates.

ESCOSA (2003)	2004	5 %	ESCOSA considered that the 5 per cent retail margin allowed for in SAIIR's previous report continued to reflect the unique characteristics of the South Australian market, including a single dominant retailer, peaky load, and emerging competition.
IPART (2004)	Jul 2004 *to* Jun 2007	2 %	IPART considered that the retail margin should reflect the risk associated with energy purchasing costs, customer default and bad debt, and competition from electricity substitutes. IPART considered that higher retail margins in Victoria are not an appropriate benchmark, because standard retailers in NSW are protected from energy purchase risk by the ETEF.
ESCOSA (2005)	Jan 2005 *to* Dec 2007	5 %	ESCOSA considered that Victoria was a better benchmark than NSW because standard retailers in NSW were protected from energy purchase risk by the ETEF. ESCOSA used a return on investment methodology to confirm that a 5 per cent margin was reasonable. The methodology included a return on capital, depreciation, amortisation, taxes and profit.

Table 11: Electricity retail margins in other regulatory decisions

See Table 3 for list of sources.

5.5 CONCLUSION ON RETAIL MARGIN

The results of the three approaches to estimating the retail margin are broadly consistent.

Our estimation of the retail margin using the bottom-up approach implies a margin of between 4.1 per cent and 4.8 per cent. This range is consistent with the base case of Integral/NERA's bottom-up approach, at 4.2 per cent.

The expected returns approach implies a margin of between 4.4 per cent and 6.4 per cent.

Benchmarking against jurisdictions in which retailers are not protected from energy purchase risk by some regulatory mechanism reveals that there is some consensus among regulators that the appropriate retail margin is between 3 per cent and 5 per cent. Our analysis suggests that EBITDA margins for a MMNE are about 1 per cent higher than EBIT margins. To the extent that the regulatory determinations report EBIT margins, this implies a margin closer to the range of 4 per cent to 6 per cent is considered appropriate by these regulators.

On the basis of these results, we recommend a MMNE retail margin of between 4 per cent and 6 per cent. This recommended range, and its relationship to the results from the three approaches to estimating retail margin, is set out in Figure 7.

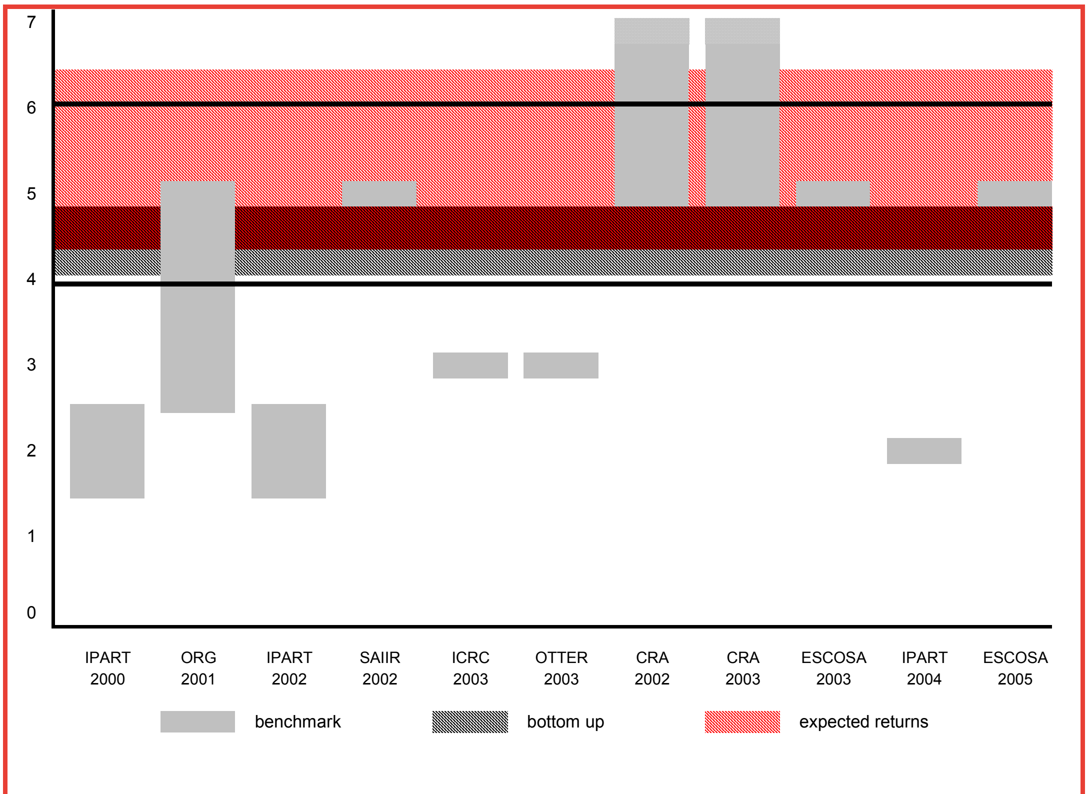

Figure 7: Results for retail margin (all benchmarked jurisdictions)

Appendix A – Example of expected returns approach

Consider the following example, which is formulated under the one-period assumption commonly used in finance practice. In reality, a MMNE is expected to earn profits over an extended period of time. But for expositional purposes, we illustrate the basic concept in this one-period framework.

The representative firm expects to sell 100 units of a product and to incur costs of $90,000. These costs comprise $20,000 of fixed costs and $70,000 of variable costs ($700 per unit). The after-tax cost of capital is estimated at 10 per cent, implying that the firm must set a price for its product, such that its expected earnings will be sufficient to generate a return on investment of 10 per cent. At this stage, the investment base is unknown, but is theoretically the present value of the expected future earnings. The firm is all-equity financed and we ignore dividend imputation for the time being (of course leverage and dividend imputation are accounted for in our estimated range for the retail margin for a MMNE below). The corporate tax rate is 30 per cent.

Suppose that management decides to sell its 100 units for $1,000 each, which would generate expected sales of $100,000 and expected earnings before interest and tax (EBIT) of $10,000, as shown in Table 12. This corresponds to an EBIT margin (EBIT/Sales) ratio of 10 per cent.

Income statement item	*Computation*	*$*
Revenue	100 x $1000	$100,000
Variable costs	100 x $700	$70,000
Fixed costs		$20,000
Earnings before interest and tax (EBIT)		**$10,000**
After-tax cash flow		**$7,000**

Table 12: Example income statement

Given this one-period example, we are able to compute the value of the investment as the present value of expected future cash flows. Applying the discount rate of 10 per cent to the expected after-tax cash flow of $7,000, the value of the firm is $6,364, computed as follows:

$$V = \sum_{i=1}^{n} \frac{E(CF_i)}{(1+r)^i} = \frac{7{,}000}{1.10} = 6{,}364$$

where:

V = value of the firm at time 0;
$E(CF_i)$ = expected cash flow to the firm in year i;

n = number of years of expected cash flows; and
r = the risk-adjusted cost of capital.

Is this price sufficient to compensate the firm for the potential variation in its cash flows as a result of systematic risk? The simplest formulation to account for this variation is to consider the case in which cash flows could be higher or lower than expected. The *expected* cash flows used for valuation are a probability-weighted average of these two possible cash flows.

Suppose that in a high-growth economic state, volume is likely to be 5 per cent higher than expected, and that in a low-growth economic state, volume is likely to be 5 per cent lower than expected. There is an equal probability of each of these high- and low-growth economic states. In these circumstances, the high-growth economic state would result in revenue of $105,000 and EBIT of $11,500, compared to revenue of $95,000 and EBIT of $8,500 in the low-growth state. The impact of fixed costs translates a 5 per cent change into revenue to a 15 per cent change in operating earnings. We refer to this ratio of 3 times (15 per cent relative to 5 per cent) as the degree of operating leverage (DOL).

Figure 8 illustrates the revenue, EBIT and return on investment associated with each of these economic states. In the high-growth economic state, realised returns are 27 per cent, compared to –6 per cent in the low-growth economic state. That is, under the assumed discount rate of 10 per cent the present value of the expected cash flow is $6,364 as computed above. If the high-growth economic state occurs, a year-end cash flow of $8,050 will be realised. This amounts to a return of 27 per cent on the initial $6,364 value (6,364 × 1.27 = 8,050). Conversely, if the low-growth economic state occurs, a year end cash flow of $5,950 will be realised, which amounts to a –6 per cent return on the initial value of $6,364.

If there is a 50 per cent chance of revenue being above or below initial expectations, the standard deviation of potential returns is 17 per cent, computed as follows:

$$\sigma = \sqrt{\sum_{j=1}^{m} p_j \left[r_j - E(r)\right]^2} = \sqrt{0.5 \times [0.27 - 0.10]^2 + 0.5 \times [-0.06 - 0.10]^2} = 0.17$$

where:

σ = standard deviation of returns;
p_j = probability of event j for $j = 1$ to m events;
r_j = realised returns given event j; and
$E(r)$ = expected return on investment.

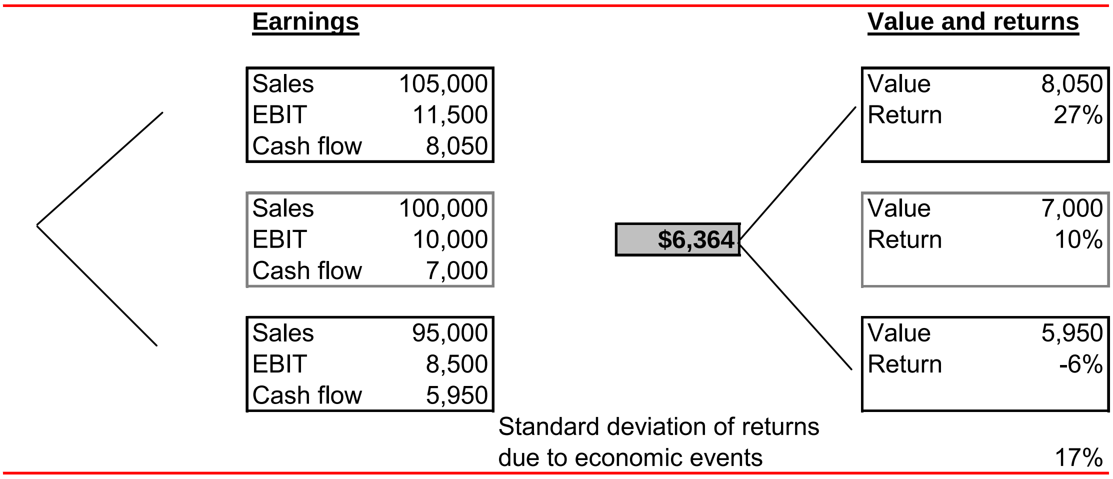

Figure 8: Example earnings and returns in high- and low-growth economic states

Note: expected values represented between the upper and lower nodes

This discussion implies that an EBIT margin of 10 per cent is consistent with an expected return of 10 per cent and a standard deviation of expected returns (due to variation in economic events) of 17 per cent. The question is whether this reward-for-risk trade-off is consistent with evidence we observe in the broader market. More specifically, we need to measure whether the expected return of 10 per cent is consistent with the systematic risk of those returns. Our approach is to examine a range of metrics including EBIT margin, expected returns and risk, and to ensure that they are all consistent with one another and consistent with market data from comparable firms. The present example is designed to illustrate how one might assess whether an assumed set of inputs are internally consistent.

To measure the systematic risk of the expected returns we need to consider the likely movements of the equity market in high- and low-growth economic states. Suppose that the expected return on the equity market is 12 per cent with a standard deviation of 20 per cent. The expected return of 12 per cent is the sum of a risk-free rate of 6 per cent and a market risk premium of 6 per cent. These same assumptions also imply that the expected return of 10 per cent for the representative firm in our example is consistent with a beta estimate of 0.67 according to the following computation:

$$\beta_e = \frac{r_e - r_f}{mrp} = \frac{0.10 - 0.06}{0.06} = 0.67.$$

Given the same 50/50 chance of the economy growing at above- or below-expectations, to arrive at an expected return on the equity market of 12 per cent with a standard deviation of 20 per cent requires potential returns of 32 per cent in the high-growth state, and returns of -8 per cent in the low-growth state. Returns with this level of dispersion are typical of what we have observed in the equity market over the last 100 years. Of course, it is rare that the equity market rises or falls by these amounts in a given year, but these numbers are simply the result of using a simple one-period, binomial model for the present example. In reality, we observe several observations closer to the expected value of 12 per cent, but we also observe occasional values well outside of these two extremes. (Our full analysis below uses the entire distribution of returns.)

The association between returns to the representative firm in our example and returns on the market is illustrated in Figure 9.

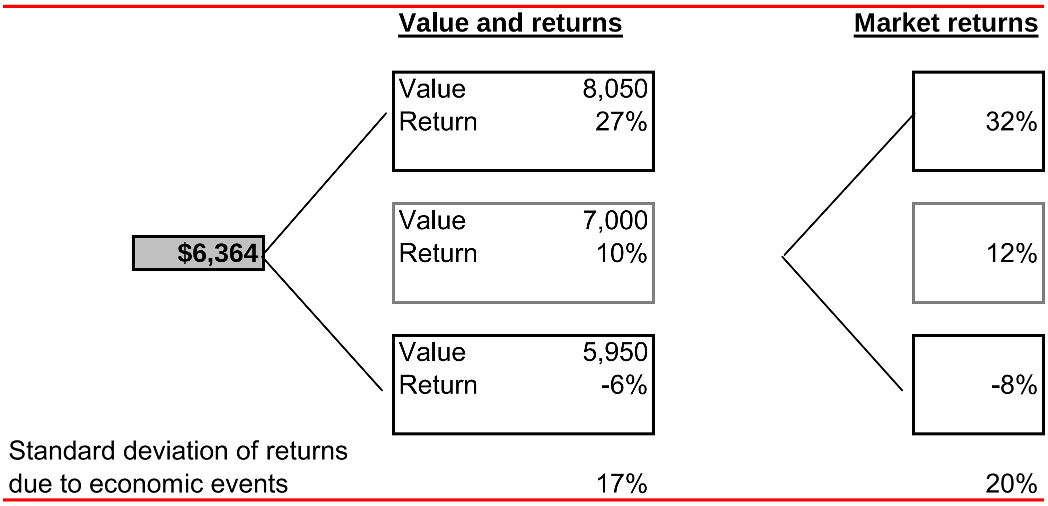

Figure 9: Association between asset returns and market returns

Note: expected values represented between the upper and lower nodes

From these returns we can measure the systematic risk of returns to the representative firm. The asset beta turns out to be 0.83 (calculated below), which exceeds the asset beta of 0.67 that was consistent with the expected return of 10 per cent. In other words, the assumed return (based on an EBIT margin of 10 per cent) is insufficient to compensate investors for the actual systematic risk they face. Beta is computed as follows:

$$
\begin{aligned}
\beta_e &= \frac{COV(r_e, r_m)}{\sigma_m^2} \\
&= \frac{\sum_{j=1}^{m} p_j \left[r_{e,j} - E(r_e)\right]\left[r_{m,j} - E(r_m)\right]}{\sigma_m^2} \\
&= \frac{0.5 \times [0.27 - 0.10] \times [0.32 - 0.12] + 0.5 \times [-0.06 - 0.10] \times [-0.08 - 0.12]}{0.04} \\
&= 0.83.
\end{aligned}
$$

To this point, we can say that the expected earnings from the investment are insufficient to compensate investors for the systematic risk they face – the expected returns have a beta estimate of 0.83 but the level of expected returns is only 10 per cent, which is sufficient compensation only for a beta estimate of 0.67. Thus, the EBIT margin of 10 per cent produces a return that is insufficient compensation for risk – the EBIT margin must be increased to produce an appropriate balance of risk and return. The relevant question then becomes, "What price will increase expected cash flows to the level where the expected cash flows provide appropriate compensation for systematic risk?"

In this case, that price is $104 per unit, equivalent to an EBIT margin of 13.5 per cent. This is documented in Figure 10 below. At a price of $104 per unit, expected cash flows are $9,830, which have a present value of $8,936. In the high-growth economic state, expected cash flows are $11,021, which provides a return of 23 per cent. In the low-growth economic state, expected cash flows are $8,638, which provides a return of –3 per cent.

Importantly, the systematic risk of these potential returns as measured by beta is 0.67, so we have consistency between the systematic risk of returns and the level of expected returns. That is, increasing the level of cash flows across all economic states has: (1) increased the present value of those cash flows; and (2) reduced the systematic risk of returns. The resulting returns are less risky such that an expected return of 10 per cent is appropriate compensation for them. Thus, we have found a set of cash flows (i.e., an EBIT margin) that is all perfectly consistent with the risk and return to equity holders. Our approach is to benchmark the risk (beta), return, EBIT margin, and other metrics against comparable firms to ensure that we have consistency among all parameters within our framework and also consistency with market data.

The dispersion of potential cash flows and expected returns is illustrated in Figure 10 and the beta can be computed as:

$$
\begin{aligned}
\beta_e &= \frac{COV(r_e, r_m)}{\sigma_m^2} \\
&= \frac{\sum_{j=1}^{m} p_j \left[r_{e,j} - E(r_e)\right]\left[r_{m,j} - E(r_m)\right]}{\sigma_m^2} \\
&= \frac{0.5 \times [0.23 - 0.10] \times [0.32 - 0.12] + 0.5 \times [-0.03 - 0.10] \times [-0.08 - 0.12]}{0.04} \\
&= 0.67.
\end{aligned}
$$

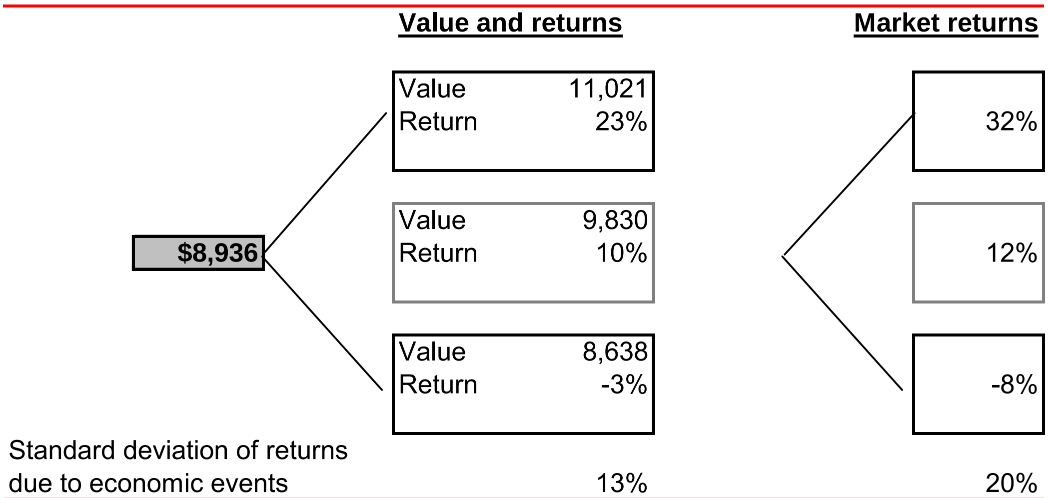

Figure 10: Association between asset returns and market returns where the expected EBIT margin is 13.5%

Note: expected values represented between the upper and lower nodes

Multi-period application

This one-period illustration of the framework can be extended to account for returns earned over a time period greater than one year. As the time period over which returns are earned increases, the required EBIT margin decreases. This occurs because the returns in each period are a combination of two factors – the cash flows generated in each period plus the present value of expected future cash flows. As the time period is extended, a greater proportion of asset value is contributed by the cash flows that are expected to be earned over subsequent future periods. This means that returns in each period are less sensitive to the variability of near-term cash flows.

In this section, we extend the illustration to the case where the asset has a life of ten years. We maintain the assumptions that variable costs are $70 per unit, fixed costs are $20,000 and expected units in the first year are 100. In each year, there is a 50/50 chance that volume growth could be 5 per cent higher or lower than the expected value of zero. This means that in year 1, the firm could sell 105 units or 95 units. In year 2, conditional upon Year-1 sales of 105 units, volume could rise to 110 units or fall to 95 units. If first-year volume was 95 units, second-year volume could rise to 100 units or fall to 90 units, and so on. Figure 11 illustrates the potential volume outcomes in each year and the probability associated with each potential volume.

Year	1	2	3	4	5	6	7	8	9	10
Volume										
	1,050	1,103	1,158	1,216	1,276	1,340	1,407	1,477	1,551	1,629
	950	998	1,047	1,100	1,155	1,212	1,273	1,337	1,404	1,474
		903	948	995	1,045	1,097	1,152	1,209	1,270	1,333
			857	900	945	993	1,042	1,094	1,149	1,206
				815	855	898	943	990	1,040	1,092
					774	812	853	896	941	988
						735	772	810	851	894
							698	733	770	808
								663	697	731
									630	662
										599
Probabilities										
	50%	25%	13%	6%	3%	2%	1%	0%	0%	0%
	50%	50%	38%	25%	16%	9%	5%	3%	2%	1%
		25%	38%	38%	31%	23%	16%	11%	7%	4%
			13%	25%	31%	31%	27%	22%	16%	12%
				6%	16%	23%	27%	27%	25%	21%
					3%	9%	16%	22%	25%	25%
						2%	5%	11%	16%	21%
							1%	3%	7%	12%
								0%	2%	4%
									0%	1%
										0%

Figure 11: Potential volume under the assumption that volume growth could be 5% above or below expected growth of zero.

Figure 11 illustrates the variability in potential volumes over time in response to different economic conditions. This variation in potential volume necessarily leads to variation in asset returns. As with the one-period illustration, the issue is, "What is the appropriate price or EBIT margin which generates sufficient expected cash flows to compensate investors for the systematic risk of those cash flows?"

Our technique for answering this question is as follows:

1. For a given price, model the potential cash flows in each year associated with each potential volume outcome presented in Figure 11.
2. Model the potential asset values in each period as the present value of expected (probability-weighted) future cash flows.
3. Model the distribution of terminal year asset values under the assumption that intermediate-year cash flows are reinvested in assets that continue to generate comparable returns to the firm in question.
4. Compile the distribution of total returns associated with each of these terminal-year asset values, and the distribution of total returns on the market portfolio, under the assumption that the market has an expected return of 12 per cent and a standard deviation of 20 per cent.

5. Compute the systematic risk of the total returns on the asset, as the covariance of asset returns with market returns relative to the variance of market returns. Compare this beta computation with the beta estimate assumed in the original cost of capital (0.67 in this illustrative example). Then we check for consistency between the systematic risk assumed in determining the discount rate and the systematic risk of the returns generated from the particular EBIT margin assumption.

6. Adjust the initial price (which necessarily means adjust the initial EBIT margin) such that the systematic risk of returns computed in step 5 is the same as the systematic risk assumed in the discount rate (i.e., ensure internal consistency). This is the EBIT margin that is sufficient for investors to earn a return that provides compensation for systematic risk.

To complete the illustration, we present in Table 13 computations of asset and market returns over the ten-year period, under the assumption that the initial price is set to $102 per unit, which is consistent with an EBIT margin of 11.4 per cent. At this initial price/margin, the asset has a beta estimate of 0.67, which was the same level of systematic risk assumed in the initial discount rate estimate of 10 per cent. We have highlighted economic states 4 – 8 which have a cumulative probability of occurrence of 89 per cent.[38] Within this range, the annualised returns on the asset range from 4 – 17 per cent, compared to a range of 3 – 18 per cent for the market.

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[38] That is, states 1 and 11 are highly unlikely to occur – these states would require uniformly good or uniformly bad economic performance every year over the analysis period. States in the middle of the range represent outcomes in which general economic performance was good in some years and poor in others.

Economic state	Cumulative returns (%)		Annualised returns (%)		Probability (%)
	Asset	Market	Asset	Market	
1	718	1506	23	32	0.1
2	591	1019	21	27	1.0
3	475	680	19	23	4.4
4	371	444	17	18	11.7
5	277	279	14	14	20.5
6	191	164	11	10	24.6
7	114	84	8	6	20.5
8	44	28	4	3	11.7
9	-19	-11	-2	-1	4.4
10	-76	-38	-13	-5	1.0
11	-128	-57	na	-8	0.1
Expected	202	211	10	12	
Variance	171	356			
Covariance	237				
Beta	0.67	(i.e. 237/356)			

Table 13: Cumulative returns, probabilities and beta computation under the assumption that the initial EBIT margin is 9.3 per cent.

The cells labelled "na" represent the cases in which the cumulative asset return is less than -100 per cent, which represents the situation where cumulative losses are greater than the initial investment value.

According to this estimation technique, the appropriate EBIT margin for a MMNE is a function of the following five assumptions:

- the systematic risk of returns as measured by asset beta;
- operation leverage as measured by the proportion of costs which increase at a constant rate with changes in volume;
- percentage change in volume in response to economic conditions;
- variance in market returns; and
- asset life.

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