Comment on issues arising from the Victorian Electricity Distribution Price Review 2006-2010

A submission to the Essential Service Commission on behalf of:

Australian Industry Group
Energy Action Group
Energy Users' Association of Australia
St Vincent De Paul
Victorian Council of Social Service
Victorian Employers' Chamber of Commerce and Industry

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This submission to the Essential Service Commission is made on behalf the Australian Industry Group, Energy Action Group, Energy Users' Association of Australia, St Vincent De Paul, Victorian Council of Social Service, Victorian Employers' Chamber of Commerce and Industry.

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The views and interpretations expressed in this paper are those of the sponsoring consumer groups.

Summary

This submission comments on key issues for consumers arising from an analysis of proposals submitted by the five Victorian electricity distribution businesses (DBs) and the Essential Services Commission's (ESC) *Issues Paper - Electricity Distribution Price Review 2006-2010* and its subsequent *Position Paper*.

The resources provided to consumer groups to assist participation in the ESC's review are modest in comparison to those available to the DBs and the ESC. Accordingly, the report focuses on a number of key issues that are judged to be of critical importance to, and will impact on costs borne by consumers. No attempt has been made to deal with all issues raised by the ESC.[1]

Issue 1: Can the ESC demonstrate that efficiency gains will be transferred to consumers?

The ESC's *Position Paper* acknowledges that the '*approach developed by the ORG for the 2001-05 determination appears to have been* remarkably *successful*' (original emphasis). There is no doubt that is correct. The DBs have earned substantially higher profits than anticipated by ORG in 2000, while service standards targeted by ORG for 'incentive' payments have generally improved.

We have no doubt that the key issue for the ESC in this review is to demonstrate to consumers how they will benefit from the efficiency gains that have obviously been achieved by all DBs in the current regulatory period.

Ensuring consumers benefit from efficiency (as required by the *Tariff Order* and other relevant Victorian legislation) is an essential tenet of the regulatory regime implemented by ORG/ESC. Delivering to end-uses their share of the benefits the DBs have achieved will require the ESC to demonstrate that it can deal with 'strategic' behaviour and 'financial engineering' by the DBs - both of which are perfectly legal.

Failure by the ESC to clearly explain what the efficiency benefits are, how much they are worth and to satisfy consumers that they will achieve these benefits would seriously undermine consumer acceptance for continuing incentive regulation of energy utilities in Victoria and possibly elsewhere.

It appears from the *Issues Paper* that the ESC understands this challenge. However, the *Position Paper* appears to focus on the ESC's concern about how best to ensure the profit incentives in the regulatory framework do not lead to long-term degradation of asset condition and service level. The *Position Paper* refers to concerns such as '*the criticality of infrastructure investment*' and the risk to infrastructure investment '*arising from regulatory processes that may be too short term in their focus*.'

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[1] It should also be noted that the dollar values quoted in this report are based on analysis of information contained in the ESC's *Annual Performance Reports* and the DBs' submissions. The impact of discrepancies in financial information contained in the DBs' regulatory accounts or adjustments arising from application of the ORG/ESC 'efficiency carry-over mechanism' have not been considered in this report and are not included in the dollar values quoted. In addition, the *Position Paper* notes that the DBs have submitted revisions to their original proposals, which are not taken into account in the values quoted in this paper. The dollar values may, therefore, differ from comparable amounts quoted by the ESC in its papers.

End users would be extremely concerned if the ESC were to adopt an approach to regulation based on the 'campaign' being run by regulated businesses and their lobbyists about a lack of investment. Indeed, the ESC refers to the '*strong incentive on the part of the distributors to "talk up" future expenditure, and "talk down" future revenue*'.

It is clear the DBs are attempting to exercise strategic behaviour by ramping up their forecast costs way above levels they achieved over the last decade. They did the same thing in the electricity distribution price review in 2000 and it paid them good dividends as the ORG was prepared to provide them with significant Capex and Opex for the regulatory period now ending (see comments below).

We believe it is absolutely essential for the ESC to demonstrate clearly that it can deliver a fair and reasonable outcome from this review. The ESC must find a way to address this without imposing further inefficient costs on consumers.

The preliminary analysis presented in this report, which is consistent with information presented in the ESC's *Position Paper*, shows that:

- ORG's 2000 Decision (and subsequent Appeal) delivered between \$75 and \$150 million/year in above benchmark revenue benefits to the DBs (that could total \$500-600 million by the end of the current regulatory period);

- an additional benefit of some \$330 million (Jun04) was achieved through the same mechanism in the 1996-2000 period; and

- the total efficiency benefits captured by the DBs, because actual costs were below the level adopted for (supposedly) efficient revenue building block cost benchmarks, are, <u>at least</u> –

    - \$215 million (Jun04) in the 1996-2000 period for Opex costs alone (noting that Capex efficiency gains were possibly modest because the DBs invested more than forecast in the last 2 years of this period); and

    - Opex efficiency gains of between \$45 million and \$60 million/year have been achieved in the first three years of the current regulatory period (ignoring any additional benefit accrued by AGL, Citipower/Powercor and United Energy through the Related Party arrangements identified by the ESC).

    - Capex efficiency gains in the current regulatory period are more difficult to estimate, but an indicative figure would appear to be in the range of \$10-20 million per year.

That is, cumulative benefits above efficient cost and efficient revenues that have been captured by the DBs since 1996 appear likely to exceed \$1.3 billion by the end of the current regulatory period. This is equivalent to about 10% of the total cost of distribution services paid by consumers.

The ORG/ESC 'efficiency carry-over mechanism' implemented in 2001 allows the efficiency benefits captured in the current regulatory period to accrue to the DBs through to 2010. This same mechanism is meant to deliver all of the efficiency benefits to consumers after 5 years. The ESC must ensure this happens – and is seen to happen. The ESC must clearly specify and set out the nature and amount of the efficiency gain in its determination and show how this will be returned to consumers.

Issue 2: Can the ESC demonstrate that it is capable of dealing with the DBs' strategic behaviour?

It is notable that even in the first year of the current regulatory period, the DBs benefited by achieving a revenue outcome nearly $70 million above the efficient benchmark revenue set only a month or so before the start of the year. In 1996, actual revenue was around $35 million above the (supposedly) efficient benchmark revenue set by Government. In fact, actual revenue has exceeded efficient benchmark revenue every year since the DBs were privatised.

The out-performance of revenue projections very early in a regulatory period suggests that the DB forecasts of sales volumes were excessively conservative. If the DBs forecast lower sales volumes, they are able to set higher unit prices and capture a benefit that is unrelated to efficient operation. It is true that sales volume forecasts are uncertain, but robust forecasts would be expected to be more accurate in the early years of the regulatory period. This has manifestly not been the case and the possibility that the DBs are exercising strategic behaviour in their forecasts must be addressed by the ESC.

There is no doubt, in Victoria at least, that the form of regulation implemented by ORG/ESC works. Overall, the DBs continually out-perform (supposedly) efficient cost and revenue benchmarks. However, as stated above, the incentive regulation articulated by ORG in its 2000 Decision, requires the efficiency benefits achieved by the DBs to be transferred to consumers after no more than 5 years.

If this occurs – and can be verified to customers to their satisfaction – it would be a welcome outcome and concrete benefit of incentive regulation. But it may not happen unless the ESC applies its theory with rigour, clarity and determination.

The diagrams and analysis in the ESC *Papers*, and those presented in Sections 2 and 3 of this submission,[2] show that efficiency benefits embedded in the DBs' revenue forecasts for the next regulatory period are overwhelmed by clear strategic behaviour in forecasting increases in both operation/maintenance and capital expenditure costs (or by excessive costs in meeting technical and safety standards in the interval metering roll-out). The level of forecast costs are totally unrecognisable compared to actual cost trends indicated over the last decade.

Of particular concern are the forecast costs associated with the interval meter roll-out that has been mandated by the ESC. The unit costs for this roll-out appear to be 5 to 6 times higher per metering point than the much more functionally useful (e.g. communications and load-control capable) metering roll-out that is underway in Italy. The DBs meter roll-out costs also appear to be 2 to 3 times higher than the Ontario electric utilities own estimates for a Victorian-scale interval meter roll-out (and the Ontario costs for interval meters appear to be much higher than equivalent meters in Australia).

[2] See pp 3, 4 and 8.

We acknowledge that the Italian roll-out, which covers more then 30 million metering points, will benefit from economies of scale that are unachievable in Australia. We also acknowledge that electricity safety standards and occupational health and safety standards are likely to increase the cost of meter replacements for some, possibly a significant number of meter installations.

But it is inconceivable that economy of scale benefits would reduce unit costs by the amount indicated by comparison between the DBs' proposals and costs publicly reported by the Italian company *ENEL Distribuzione Spa* and those attributed to the Ontario utilities. The only possible conclusions are that technical and safety standards are adding excessively to costs, which the ESC should examine closely, or that the DBs have excessively padded their cost forecasts.[3]

Issue 3: Why should Victorian DBs benefit from a higher cost of capital than allowed by all other jurisdictional regulators?

Another key issue for the ESC to explain to consumers is why it has been setting the weighted average cost of capital (WACC) at the high end of the range established by Australian regulators over the last decade. This outcome is imposing significant costs on Victorian electricity users and providing a 'regulatory windfall gains' to the DBs for no apparent reason. In the process, electricity prices in Victoria are higher then they should be and the competitiveness of Victorian businesses is adversely impacted.

The ESC expresses no views in its *Issues Paper* on what the WACC should, or might, be for the next regulatory period – despite the fact that all DBs have proposed that WACC should be increased to even higher levels. Similarly, the ESC takes no firm position in its *Position Paper* other than stating that there is '*potential value transfer*' (from DBs to consumers) from '*the reduction in the real WACC*', but only because '*real interest rates, as measured by the prevailing yield on index linked government bonds (around 2.8 per cent), are lower now than they were at the time of the 2001-05 price determination*'.

The material in this report demonstrates that the ORG/ESC has been notably more generous to regulated energy distributors than any other jurisdictional regulator – each of whom openly acknowledge that they are being 'cautious and/or conservative' (i.e. giving energy utilities the benefit of doubt on the value of WACC). The ESC has also set a much lower WACC for Victoria's water businesses, even though risk profiles would appear to be similar. The material in this report also suggests that all Australian regulators are being excessively cautious, and all could set WACC at lower levels without unsettling efficient capital providers.

This needs clear explanation and justification by the ESC because its value of WACC imposes very substantial costs on consumers - of at least $55 million/year[4].

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[3] This latter possibility cannot be proved conclusively from information in the public domain because the level of disclosure of scope, timing, cost and numbers of complex installations is insufficient to replicate or test the DBs' proposals in any way. This is itself a cause for concern because of the large costs involved and the DBs' apparent disregard for the fact that their customers must pay for this.

[4] Total regulatory asset value times the difference in WACC values between ORG/ESC and other jurisdictional regulators.

Issue 4: Dealing with Related Party Transactions and Service segregation.

We also note in particular that the ESC has raised concerns about the reliability of reported financial information given the existence of Related Party arrangements entered into by AGL, Citipower/Powercor and United Energy. There is no reason why the DBs' owners should not use this mechanism to control costs and stimulate fiscal discipline by DB managers. But Related Party arrangements should not be used as an artifice to prevent real efficiency gains being delivered to consumers as intended by the ORG/ESC efficiency carry-over mechanism. The ESC needs to ensure that benefits are delivered to consumers and preserve the integrity of the regime it administers.

In addition, the ESC's *Papers* isolate metering costs for the current regulatory period and deals separately with issues associated with Prescribed Services revenue and Excluded Services revenue (which will include all metering costs from 2006).

We take on faith that the ESC is doing its best, in its *Papers*, to explain the complexity of Related Party arrangements and metering costs to consumers, but the way these are handled in the ESC's *Papers* is confusing. For example, the estimates of Related Party 'dilution' of reported efficiency gains is not transferred into the ESC analysis of DB proposed costs; and insufficient detail is provided on metering costs in the current regulatory period to correlate the ESC's analysis with other information in the ESC's public domain reports.

The ESC's treatment of these matters may not impact on the end result, but it continues the confusing way financial information and metering costs have been presented (or not presented in the case of Excluded Service Charges and some specific metering costs) to consumers in the ESC's Performance Reports and the DB Annual Tariff Reports over the current regulatory period.

Issue 5: The cost and value to consumers of the interval meter roll-out.

The ESC's treatment of the costs and benefits of the interval meter rollout is very confusing – and the costs proposed by the DBs clearly excessive. The revised meter rollout costs presented in the ESC *Position Paper* result in forecast (incremental) metering services revenue growing for a total of $61.3M in 2006 up to $175.6M in 2010 (and $207M by 2012). This translates into an incremental additional price impost between $5.22/year and $54.26/year for single phase meters and could add up to 10% to a typical small consumer bill.

It is difficult to understand why the DBs' proposed interval metering costs are so high. The total cost of the meter and installation is about 4 to 6 times the average total cost of the ENEL roll-out in Italy, which not only includes an interval meter but also sophisticated two-way powerline carrier communications technology with capability to offer interactive load control, and the IT systems required to handle all the data.

The DBs meter roll-out costs also appear to be up to 3 times higher than the Ontario Electricity Distributors' Association estimates for a Victorian-scale interval meter roll-out of 800,000 meters over 3 years (and the Ontario costs include Stranded Asset recovery and interval meters capital costs that appear much higher than equivalent meters in Australia).

The ENEL roll-out does offer opportunities to exploit economies of scale that could not be achieved by any of the Victorian DBs, but it is inconceivable that a unit cost up to 600% higher could be efficient even for a smaller scale roll-out.

It is also extremely disturbing that the ESC shows no inclination to consider roll-out of any technologies that would allow consumers to access automatic, low-cost load control technology that would assist them manage the cost impact of implementing time-of-use tariffs that reflect the cost of increasing peak load. The ESC has rejected (an admittedly inadequate) proposal by CitiPower and Powercor to undertake what appears to be a limited roll-out of antiquated ripple control technology.

It is particularly disturbing that the ESC's initial position is that: "*No submissions indicated that customers were (1) willing to have loads controlled by the distributor, and (2) prepared to pay the additional cost for the "ripple control" technology*. The ESC has, in fact, received a number of submissions from consumer groups since 2000 suggesting that remote load control should be examined closely. This is particularly because application of time-of-use tariffs, similar to United Energy's, will adversely impact large numbers of AC-using consumers – something that the ESC should be aware of since this was the subject of a submission made to the ESC on behalf of CUAC in 2003.

Without automatic load control capability, adversely affected consumers have few choices – apart from denying themselves use of the ACs – if they wish to avoid substantially higher bills. If this generates adverse consumer reaction, which is very likely, the ESC may be moved to impose transitional arrangements or tariff design constraints on the DBs (and even retailers) which will drag out achievement of the benefits of interval metering over even longer time frames than already anticipated. This would be a very poor outcome for consumers forced (by the ESC) to bear higher costs.

It is essential that the ESC closely scrutinise the costs of the proposed interval meter roll-out and also closely examine how the impact of punitive cost-reflective time-of-use tariffs can be managed.

Issue: Incentives for demand management.

The ESC's and the DBs' proposals for demand management are totally unsatisfactory and noticeably out of step with programs supported by both IPART and ESCoSA.

The Demand Side Response Facility Trial undertaken by the EUAA in late 2002 showed conclusively that large end-users were interested in examining demand management initiatives. The Trial also identified a number of major obstacles, including distorted incentives in the Victoria regulatory regime for distributors, which need to be addressed. While the Trial focussed solely on large industrial and commercial consumers, the outcomes and the issues that the Trial identified are equally applicable to small consumers. Significant progress has been in addressing some of these obstacles, but the ESC and DB proposals do nothing at all to address obstacles in the Victorian regulatory regime.

The ESC would do well to follow the example of other, more progressive and consumer-focussed, regulators such as IPART and ESCoSA on this issue. The ESC could do this by developing a Demand Management Code that is similar to those adopted by IPART and ESCoSA and also replicating the range of initiatives endorsed by ESCoSA that are to be trialled by ETSA Utilities. These initiatives include:

- "power factor" improvements in business and manufacturing premises;
- trials of Voluntary Load Curtailment (VLC) programmes for large customers;
- Direct Load Control (DLC) of domestic equipment such as air-conditioners and pool pumps;
- use of standby generation, and
- the use of incentives for customers to reduce demand at times of peak demand.

These actions by IPART and ESCoSA shows that the ESC needs to provide some additional 'positive' incentives for DM as part of the next regulatory period. If it does not do this, the ESC leaves itself open to the accusation that it is out-of-touch with the latest developments in regulation, out-of-step with other regulators and out of touch with actions that could assist in protecting the long-term interests of consumers. Victoria, which badly needs a more active DM response to help it meet the challenge of growing peak demand, will be left more exposed to the consequences, including unfettered growth in peak demand, higher Capex and higher electricity costs.

1. Introduction

Marsden Jacob Associates (MJA) has assisted a consortium of Victorian consumer groups prepare this submission to the Essential Services Commission's (ESC) review of electricity distribution prices for the 2006-2010 period. The sponsoring consumer groups are:

- Australian Industry Group (AiG)
- Energy Action Group (EAG)
- Energy Users Association of Australia (EUAA)
- St Vincent De Paul
- Victorian Council of Social Services (VCOSS)
- Victorian Employers' Chamber of Commerce and Industry (VECCI)

The submission provides comment on key issues for consumers arising from analysis of proposals submitted by the five Victorian electricity distribution businesses (DBs) and the Essential Services Commission's (ESC) *Issues Paper - Electricity Distribution Price Review 2006-2010*. The comments have been developed following review of the DBs' pricing proposals and the *Issues Paper* and *Position Paper* published by the ESC.

The resources provided to consumer groups to assist participation in the ESC's review are modest in comparison to those available to the DBs and the ESC. Accordingly, the submission focuses on a number of key issues only. These issues are judged to be of critical importance to, and will definitely impact on costs borne by, consumers. The report provides commentary, analysis of data and information relating to five topics, viz. the cost of the 'efficiency incentive' constructed by the ORG in 2000, the value (to the DBs) of efficiency gains, the ORG/ESC approach to estimating the cost of capital, the cost of interval meter roll-out and the DBs proposals for demand management.

Section 2 provides a brief overview of the approach used to prepare a preliminary estimate of the cost to consumers of the efficiency incentive embedded in the Victorian electricity distribution regulatory regime.[5] This section also provides a brief commentary on how the primary profit incentive works, which it clearly does, and makes the point that, from a consumer's perspective, the ESC has a clear role to play. The ESC must sort out the impacts of strategic behaviour and 'financial engineering' (that is quite legal) by the DBs, identify and quantify the value of the efficiency gains achieved over the current regulatory period and ensure these are passed through to consumers as required by law and intended by the ORG in its 2000 Decision.

[5] Dollar values quoted in this submission are based on analysis of information contained in the ESC's Annual Performance Reports and the DBs' submissions. The impact of discrepancies in financial information contained in the DBs' regulatory accounts or adjustments arising from application of the ORG/ESC 'efficiency carry-over mechanism' have not been considered and are not included in the dollar values quoted. In addition, the *Position Paper* notes that the DBs have submitted revisions to their original proposals, which are not taken into account in the values quoted in this paper.

The dollar values may, therefore, differ from comparable amounts quoted by the ESC in its papers. However, any difference in value is secondary to the importance of the impacts on consumers of the issues raised.

Section 3 provides a preliminary estimate of the value (to the DBs) of the efficiency gains and raises questions for the ESC to address as to when an efficiency benefit becomes monopoly rent.

Section 4 addresses issues associated with the ORG/ESC's approach to estimating the weighted average cost of capital (WACC). This is a particularly important issue that requires clear explanation and justification by the ESC because of the cost it imposes on consumers. The ESC stands out amongst jurisdictional regulators in adopting a consistently higher value for WACC for energy utilities. Comment is also provided on some of the more controversial matters connected with estimating WACC that suggest the ESC (and all other Australian regulators) could reduce the value of WACC without unsettling efficient providers of capital (who have reasonable expectations).

Section 5 provides a comment on preliminary analysis of the costs proposed by the DBs for rolling out interval meters as mandated by the ESC and compares the cost of these proposals with much lower cost metering roll-out programs underway in Italy and Ontario.

Finally, Section 6 provides a very brief commentary, and extracted examples, of the DBs' proposals so far as they may affect incentives for consumers to practice or offer demand management or energy conservation.

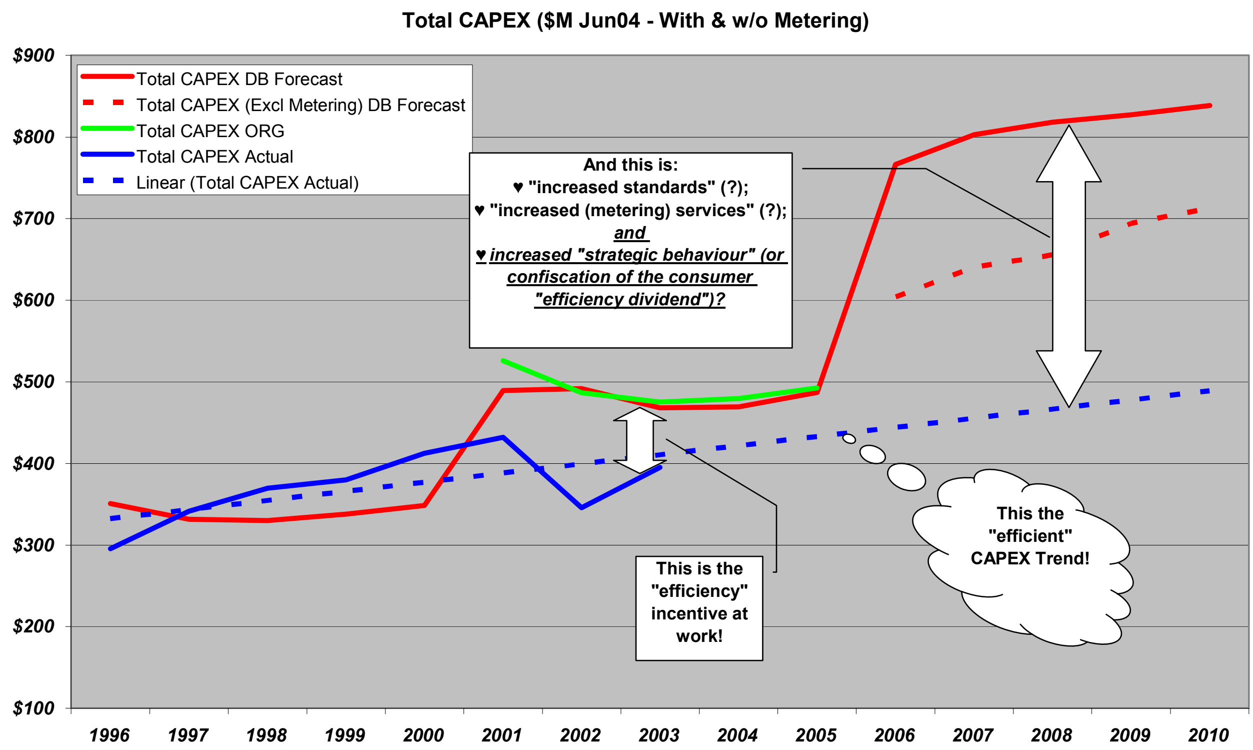
2. Where are "efficiency gains" passed to consumers?

The diagrams below present a summary of analysis comparing forecast, approved and actual capital expenditure (Capex) and operations and maintenance expenditure (Opex) for the period from 1996.[6] Costs are shown with and without the proposed interval meter roll-out, which allows direct comparison between the current and next regulatory periods.

Rather than attempting to match the presentation of data in the ESC's *Papers*, the comparisons of total cost (combining Prescribed and Excluded Service costs) use information from the DBs' proposals and ORG/ESC public domain sources. This treatment of costs is simpler and more closely related to costs included in consumers' bills. For example, small consumers' bills do not identify Prescribed and Excluded Service charges (or distribution, transmission and retail charges for that matter).

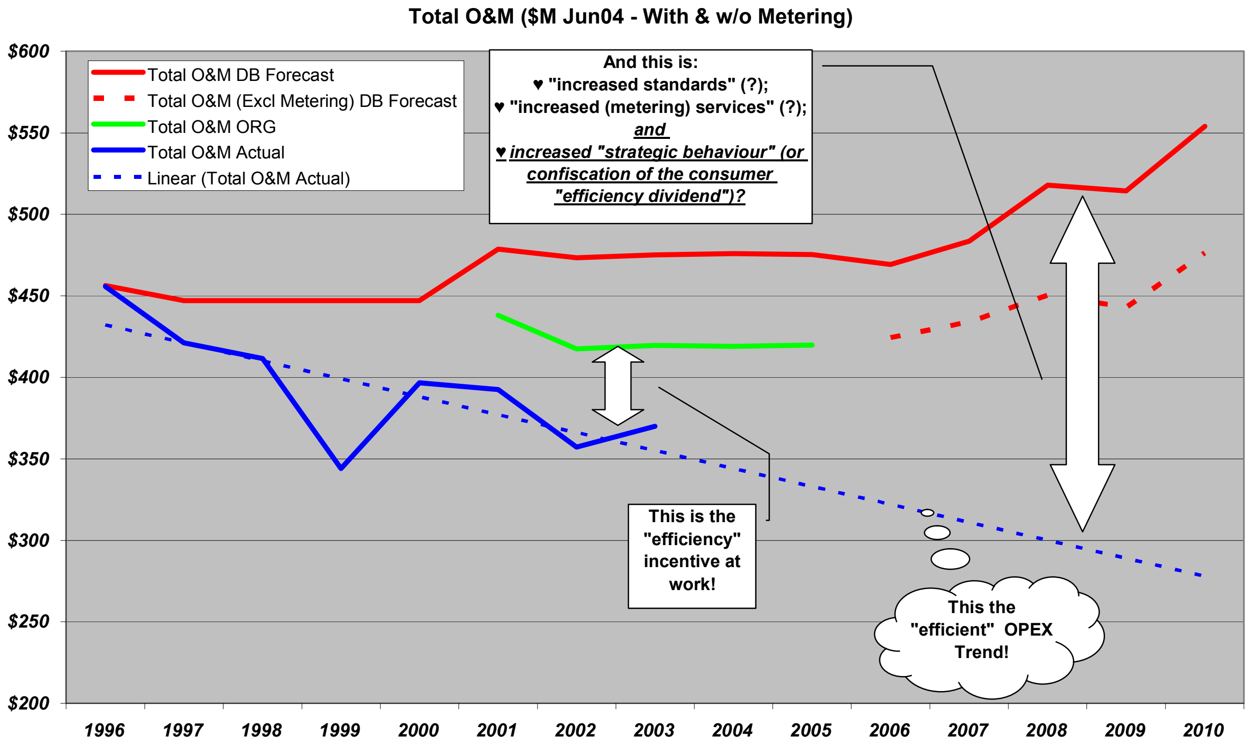
It is acknowledged that this analysis cannot deal with the impact of related party transactions on reported efficiency gains. This is certain to mean the estimates of benefits accrued by the DBs since 1996 significantly understates those benefits. Nor is it possible to compare the costs from one period to the next unless the metering costs are included (or excluded) in both. The ESC has chosen to separate metering costs from Prescribed Service costs in the current regulatory period. The diagrams in this submission are based on combining (but showing separately) metering and non-metering costs.

FIGURE 1: TOTAL CAPEX ($M JUNE 2004) WITH AND WITHOUT METERING



[6] All values in June 2004 dollars

FIGURE 2: TOTAL O&M ($M JUNE 2004) WITH AND WITHOUT METERING



It is relevant to note that estimates have been included for some DBs' forecast metering costs because only one DB provided full details of Capex, Opex, revenue projections and Excluded Service Charges for the metering components. The way information was presented by the DBs is confusing because the DBs followed the ESC's proposal to leave the value of existing metering assets in the Prescribed Services regulated asset base, while all Capex for future metering are included in the Metering Excluded Service Charge. More confusion is created by including all Opex costs for all metering in the Prescribed Services cost base. This makes it impossible to directly compare the metering cost proposals for each DB, or to replicate/confirm the ESC's analysis.

2.1. Forecasting of 'efficient' cost trends

A simple linear regression applied to (reported) actual expenditure has been used to indicate the efficient cost trend for both Capex and Opex.[7]

The 'efficient cost trend line' is indicated in the above diagrams by the dashed blue line. The difference between the actual costs and forecasts cost approved by ORG (or the Victorian Government prior to 2000) indicates how the efficiency incentive in the regulatory regime is intended to work.

[7] It is pleasing to see the ESC compare forecast, approved and actual costs in its *Papers*; but it would be preferable if the ESC adopted a trend analysis approach similar to that shown in the diagrams in this report. The consumer groups' submission to the 2001-2005 price review supported the econometric analysis methods used by UK regulators as early as 1994.

2.2. Manifestations of the 'efficiency incentive'

The way in which the incentive works also provides some guidance as to the likely extent of strategic behaviour by the DBs. There is some complexity in the different efficiency valuations and the incentive for strategic behaviour. For example, the efficiency incentive is valued differently for Capex and Opex:

- For Capex, the efficiency benefit is represented by the difference between forecast and actual Capex *times* the WACC *plus* the difference between forecast and actual Capex *times* the DB's particular depreciation rate.

  This is relatively complex because the level of Capex investment (whether forecast or actual) is not directly recovered through regulated revenue on a dollar for dollar basis. Rather, the Capex is rolled into the regulatory asset base (RAB) and the cost recovered over more than one regulatory period through the regulatory revenue building blocks for return on capital (RAB x WACC) and return of capital (depreciation).

  There is an actual or potential conflict for the DBs to resolve with the Capex efficiency incentive:

  - If a DB reduces Capex in, or delays investment beyond, any single regulatory period, it gets to keep the resulting Capex efficiency gain for a maximum of five years (through the efficiency carry-over mechanism implemented by ORG in 2000).
  - However, a reduction in Capex reduces the value of RAB for the next regulatory period and reduces the revenue building block components for return on and return of capital (in the next regulatory period).
  - If the DB delays the Capex into the next regulatory period, it faces a risk that the ESC may not allow reinstatement of the full value of deferred Capex in the next regulatory period on the basis that consumers have already paid once for (part of) the delayed Capex.[8]

  A rational response to this conflict (for the DBs) is to forecast higher Capex than a reasonable asset management planning process would suggest is required (a manifestation of strategic behaviour), then delay Capex as long as possible in the current regulatory period, but commit Capex on projects that cannot be avoided before the start of the next regulatory period.

  The impact of this rational response is inferred in the difference between forecast and actual Capex in the above diagram:

  - Capex spending increased above the forecast amounts in the latter part of the 1996-2000 period as DBs invested Capex that could no longer be avoided in response to high-profile adverse publicity about poor reliability performance;
  - DBs forecast a significant increase in Capex in 2001, which ORG (and the Appeal Panel) generally accepted – even though it was clear to consumer

[8] The ESC should closely examine this issue. Any risk to the DBs would only arise if the ESC successfully sorts out the influence of strategic behaviour in the forecasts and keeps a period-on-period track of individual Capex components. The ESC *Position Paper* devotes attention to this very matter, but appears more concerned about dealing with the risk that DBs might be running down their assets by under-investing in maintaining service capability. Both matters need to be addressed.

groups at the time that the increase, most likely, contained a significant element of strategic behaviour that ORG was reluctant to discuss or consider;[9]

- actual Capex in 2001 was significantly below the approved forecast - and actuals immediately prior to 2001 – and declined further (below the approved forecast) in 2002 as the DBs sought to maximise the efficiency gain;
- actual Capex increased in 2003, although it remains well below the levels approved by ORG.

- For Opex, the efficiency benefit is much more obvious and the reaction by DBs more straight forward. Each dollar saved by a DB (the difference between forecast and actual Opex) goes straight onto the bottom line of the DB owner's profit and loss statement (less tax, if tax is paid). Since there is no timing benefit in delaying Opex efficiency improvements, all (well-managed and profit-motivated) DBs would be expected to chase every possible Opex saving consistently throughout the regulatory period – <u>and inflate their forecasts as high as they think they could possibly get away with.</u>

The above diagrams consolidate all DBs' Capex and Opex. Individual diagrams for each DB are shown in Appendix A. It is notable that not all DB Capex and Opex trends show the same characteristics. For example:[10]

- The above-forecast Capex spending in the 1996-2000 period was more obvious for AGLE (Solaris as it was then) and Powercor, whereas Citipower, TXU (Eastern Energy) and United Energy achieved actual expenditure closer to forecast.
- In 2000, AGLE, TXU and United forecast significant increases in Capex (that were generally endorsed by ORG/Appeal Panel), and all three subsequently underspent the forecasts; whereas Citipower and Powercor both forecast Capex similar to the 1996-2000 period, and both subsequently reasonably closely matched their forecasts.
- All DBs apart from AGLE (Solaris) achieved significant reductions in Opex in the 1996-2000 period; and all DBs put forward significantly increased forecasts (above actuals) that were subsequently reduced by ORG.
- All DBs apart from AGLE achieved significant reductions in Opex from 2001, although both TXU and United report increases in Opex to near-forecast levels in 2003.

2.3. The Impact of Related Party Transactions

As the ESC implies in its *Papers*, interpretation of these varied outcomes is complicated by the related party arrangements entered into by AGLE (with Agility), Citipower and Powercor (with each other) and United (with Alinta, United's part-owner). Under these related party arrangements, Capex and/or Opex services are being provided where the

9 See comments in *Office of the Regulator-General - 2001 Electricity Distribution Price Review, Response to Draft Decision - A Consumer Perspective*, Pareto Associates Pty Ltd Report for the Customer Energy Coalition, July 2000.

10 The observations of Capex differences for individual DBs is, most likely, distorted by the impact of related party transactions where these transactions have the effect of retaining efficiency gains within the related parties while actual are reported to match (or be close to) forecasts.

costs of services are tied to the (supposedly) efficient cost benchmarks adopted by ORG in 2000.

Related party arrangements are entirely legal and could even be a useful way for the DB owners to impose fiscal discipline on DB managers. However, the ESC notes[11] that these arrangements may also allow the DB owners to capture the efficiency gains within separate businesses that they control - while reporting to the ESC the costs paid by the DB entity to the Related Party as actuals.

The ESC is correct in stating that such behaviour, even if entirely legal, is unsatisfactory because, it prevents transparent disclosure of efficient costs. The routine disclosure of efficient costs is a fundamental feature of the ORG/ESC's regulatory framework.

The ESC's *Papers* do not discuss in detail how the ESC is dealing with this challenge to its regulatory framework, other to say "(w)*ith the exception of TXU with whom full agreement has been reached, discussions between the Commission and the distributors are continuing. The key issues that remain outstanding are the treatment of related party transactions and the allocation of IT assets (CitiPower).*"[12]

One of the issues raised by the ESC is "*whether the related parties of distributors should be able to retain any efficiency gains through distributors being able to value their contracts with such related parties at other than the total costs incurred by those related parties in performing those contracts (including a reasonable allowance for profit), or whether the gains should be returned to customers over time. If the gains should be returned to customers, what proportion of them should be so returned, and over what period of time?*"[13]

From a consumer perspective, the answer to this question is simple. A fundamental tenet of the regulatory regime is that consumers are to benefit from efficiency gains. The ORG made a substantial concession to the DBs in 2000 by establishing the efficiency carry-over mechanism to provide a (more-or-less) constant incentive for DBs to pursue efficiency gains. The carry-over mechanism allows the DBs to retain the full value of the efficiency gain for a 5 year period. An equally fundamental tenet of that regulatory arrangement is that the long-term benefits of efficiency gains were to be transferred <u>in full</u> to consumers after the 5 year period.

Related party arrangements may be legal. But, if the effect of these arrangements is to deny benefits that were clearly intended to pass to consumers, then the ESC must act to ensure the benefits are passed to consumers in full and in accordance with the law and the intent of the efficiency carry-over mechanism. The DB owners would still get the full benefit intended and offered in the ORG/ESC efficiency carry-over mechanism. But they should not be permitted to use a legal or accounting artifice to prevent consumers from obtaining benefits that the ESC is required by law to deliver to them.

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[11] The ESC also refers to the fact that concern about the use of related party transactions had been raised by the Productivity Commission.

[12] p 15, ESC Issues Paper.

[13] p 17, ESC Issues Paper.

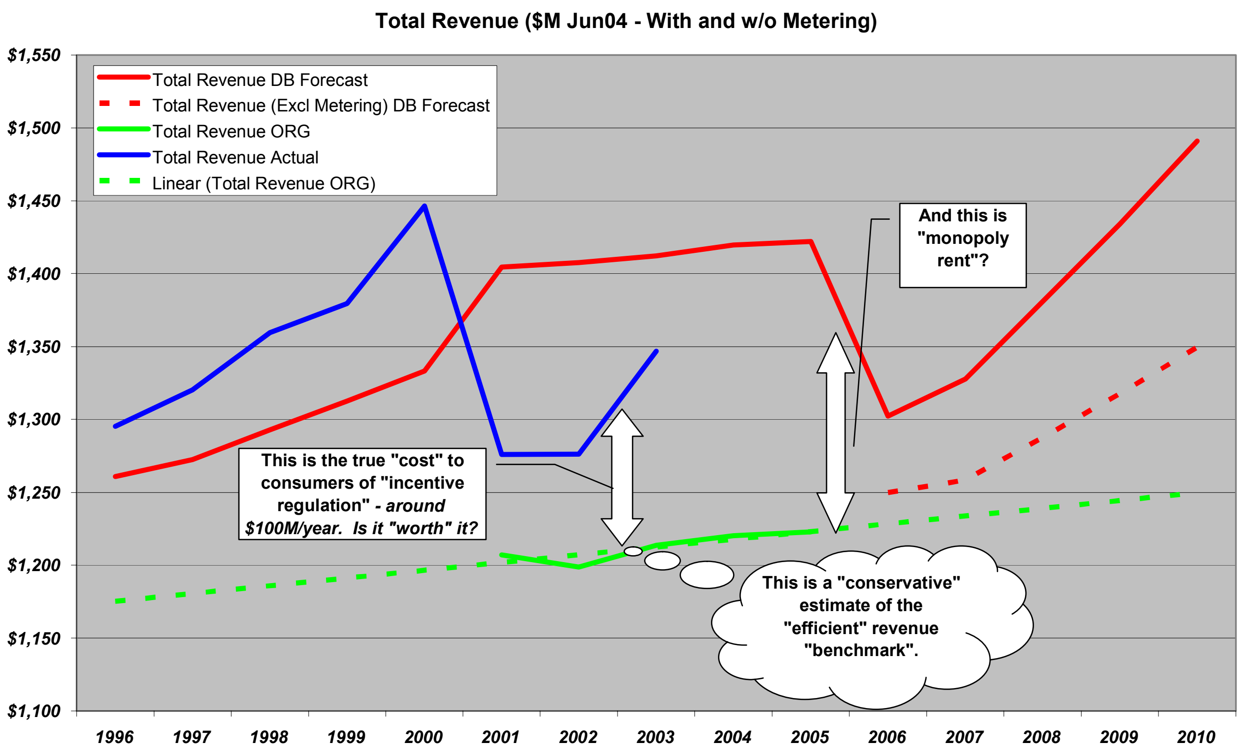
3. The Cost of Incentives. Do consumers benefit?

The diagram below shows a comparison between DB forecast, allowed and actual revenue. The DB forecasts are shown in red, with the solid red line representing forecasts that combine metering and tariff revenues and the dashed red line excluding (estimated) interval metering revenues post 2005. The actual DB revenue is shown as the blue line, with the drop in revenue from 2000 to 2001 showing the impact of ORG's 2000 Determination on actual revenues. The green lines represent ORG's estimate of 'efficient' maximum allowable revenue for the current regulatory period.

If one assumes that the ORG maximum allowable revenue (green line) is a reasonable estimate of efficient total costs;[14] then the difference between revenue at the 'green line' level and actual (represented by the Blue line) gives some idea of the cost to consumers of the regulatory regime. This difference lies in the range $75-$120M/year. In other words, the regulatory regime requires consumers to pay around $100M/year above the estimate of efficient cost for DBs to provide network services.

The form of regulation applied by ORG/ESC was developed because of concern that US-style 'cost-of-service' regulation tended to produce inefficient outcomes. The ORG/ESC's regime may be better for consumers than a 'cost-of-service' regime, but as the above analysis shows, it is clearly not cost free for consumers.

FIGURE 3: TOTAL REVENUE ($M JUNE 2004) – WITH AND WITHOUT METERING



[14] Ignoring the fact the ORG made it clear the estimate was "conservative and cautious" (i.e. deliberately over-stated the efficient revenue level).

3.1. The Impact of Strategic Behaviour

It is notable that, even in the first year of the current regulatory period, the DBs benefited by achieving a revenue outcome nearly $70 million above the efficient benchmark level set only a month or so before the start of the year. A similar outcome occurred at the beginning of the first regulatory period. In 1996, actual revenue was around $35 million above the (supposedly) efficient benchmark revenue set by Government.

In fact, actual revenue exceeded efficient benchmark revenue every year since the DBs were privatised. Out-performance of revenue projections very early in a regulatory period suggests that the DB forecasts of sales volumes were conservative. If the DBs forecast lower sales volumes, they are able to set higher unit prices and capture a benefit that is unrelated to efficient operation.

The ESC's *Position Paper* says:

> "*Forecasting is an inherently risky task, even under the most benign circumstances. In resetting price caps, however, the task is complicated significantly by the strong incentive on the part of the distributors to 'talk up' future expenditure, and 'talk down' future revenue*."[15]

It is true that sales volume forecasts are uncertain, but robust forecasts would be expected to be more accurate in the early years of the regulatory period. The possibility that the DBs are exercising strategic behaviour in their forecasts, as the ESC suggests, must be addressed.

There is no doubt, in Victoria at least, that the form of regulation implemented by ORG/ESC 'works'. As the ESC says, "*the approach developed by the ORG for the 2001-05 determination appears to have been* remarkably *successful*."[16] Overall, the DBs continually out-perform (supposedly) efficient cost and revenue benchmarks.[17]

However, the theory of regulation articulated by ORG in its 2000 Decision requires the efficiency benefits achieved by the DBs to be transferred to consumers after no more than 5 years. If this occurs – and can be verified to consumers' satisfaction – it would be a welcome outcome and concrete benefit of incentive regulation. However, the diagrams and analysis in the ESC's *Paper*s, and those presented in this submission, show that efficiency benefits embedded in the DBs' revenue forecasts for the next regulatory period are overwhelmed by what looks to be blatant strategic behaviour in forecasting increases in both operation/maintenance and capital expenditure costs (or excessively high costs of meeting technical and safety standards). The level of forecast costs are totally unrecognisable compared to actual cost trends indicated over the last decade.

The ESC clearly recognises this challenge, but does not make it clear in either the *Issues Paper* or the *Position Paper* what it intends to do to ensure consumers get the efficiency

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[15] p22, *Electricity Distribution Price Review 2006-10 - Position Paper*, Essential Services Commission, March 2005.

[16] Original emphasis. p11, *Op Cit.*

[17] We note that outcomes in Victoria have been very different to the outcomes achieved in NSW and Queensland, where all of the electricity distributors have incurred much higher Capex and Opex costs than they forecast; and performance indicators suggest service standards have fallen.

benefits they have, in effect, paid the DBs to achieve. Issues to be considered by the ESC are:

- How can it be demonstrated that consumers get $75-120 million/year worth of benefit from the current regulatory regime?
- Would the situation be different under a different regulatory regime?

3.2. Issues for the ESC to explain

The data in the diagram above suggests the following issues require further, more detailed analysis and explanation by the ESC:

- The level of actual revenue is much higher than ORG expected, which needs to be explained and taken into consideration in this reset.
- It appears that a primary incentive in the regulatory regime is for DBs to put too much effort into sophisticated gaming of demand/cost forecasts.
- The ESC should explain why it is sanctioning a regime where the DBs are paid such a high 'incentive premium' to do what they should be doing anyway.
- The interval meter roll-out costs seem very high. As discussed later in this submission, it is not clear what is driving this.[18] It could be:
  - actual higher costs (because of costs safety/technical regulation suggested by the DBs);[19]
  - inefficient roll-out configuration (the selective roll-out regime required by the ESC will undoubtedly be more costly on a per meter basis than a universal roll-out);[20] or
  - strategic behaviour in the cost forecasts by overstating the cost of the roll-out knowing that the roll-out will proceed in any case because it has been mandated by the ESC.[21]

Generally, the ESC needs to explain how consumers actually (as opposed to theoretically) benefit from the incentives in the regime. There is no doubt that the DBs have benefited. But how do consumers benefit when out-turn Return on Regulated Assets is 50-100% higher than the efficient benchmark set in 2000?

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18 The ESC has commissioned consultants to review the DBs interval meter roll-out proposals, but has advised the review will be published with the Draft Determination in June 2005.

19 The ESC's *Position Paper* says: "*In the process of replacing meters, it is expected that distributors will encounter some complex installations arising from unsafe wiring, illegal connections, switchboard replacements and asbestos meter boards*." (p208)

20 For example, the ESC's *Position Paper* shows each DB has adopted a different roll-out program. Only United proposes a 'focussed campaign' of concentrated roll-out that is likely to generate the economies of scale similar to those captured by Italian and Ontario distributors.

21 As noted later in this report, the costs forecast by the DBs are many times higher (on an average per meter basis) than costs reported for meter roll-outs underway in Italy and Ontario. These latter rollouts include sophisticated communications and load control capability that is not intended for Victoria at this stage. That is, both overseas programs will have potential to deliver more flexibility and better options for consumers, but at very much lower cost, than suggested by the DBs.

Alternatively, the ESC should explain at what level an efficiency dividend becomes monopoly rent – when there is an appearance that DBs can capture the efficiency benefit that is supposed to be passed onto consumers by over-stating their cost forecasts and understating their sales forecasts. It is of particular concern that it appears a primary incentive in incentive regulation is created by allowing opportunities for the DBs to earn above efficient benchmark profits.[22]

The regulatory regime created by the ORG/ESC allows the DBs to earn additional profits through five primary mechanisms, and a sixth mechanism is being proposed for the next regulatory period. These mechanisms are:

- reducing Capex below the forecast amounts;
- reducing Opex below the forecast amounts;
- an efficiency carryover, which allows the DBs to retain the benefits of reducing Capex and Opex for a full five-year period;
- an incentive payment to exceed service reliability performance standards;
- retention of part of the forecast amount required to make GSL and appliance damage payments; and
- the sixth mechanism proposed by the ESC is in the form of an incentive payment to meet the (already excessively costly) interval meter rollout program.

In each case, consumers pay the forecast cost and the DBs benefit in a direct financial sense by beating the forecasts. What is not clear is whether 'beating the forecasts' reflects greater efficiency in terms of a DB becoming more efficient operationally (that is more productive), or whether the DB has become more effective at playing the regulatory game and getting consumers to pay for it.

Two primary questions arise from these incentive mechanisms.

- The first is how much does each of these mechanisms actually cost consumers? For example:
  - what is the total value of the efficiency benefit to each DB for Capex and Opex;
  - what is the total value of the efficiency carryover benefit to each DB for Capex and Opex;
  - what is a total value of payment to each distributor in service/quality incentives; and
  - what is the balance in the amounts for GSL's and appliance damage?
- The second question, which is more fundamentally important, is how can consumers see they benefit from the efficiency carryover mechanism when the

[22] This submission is not suggesting that the ESC should engage in 'profit regulation', but it appears clear that a much better match is required between forecasts of efficient cost and efficient outcomes. The magnitude of differences between forecasts and actuals over the last decade strongly indicates that 'strategic behaviour' is a stronger incentive that pursuit of efficiency gains. If this is the case, it is a most unsatisfactory outcome for consumers because they are being forced to pay unnecessarily high and inefficient costs to receive a more-or-less basic level of service.

DBs argue they face pressures which will increase costs for the second regulatory period?

This comes back to the fundamental question of whether or not the ESC can differentiate between legitimate prudent behaviour by management in pricing all reasonable risks and events (that could be legitimately argued should be borne by consumers) and the exercise of strategic behaviour or gaming by the DBs.

There is no doubt that the key issue for the ESC in this review is to demonstrate to consumers how they will benefit from the efficiency gains that have so obviously been achieved by all DBs in the current regulatory period. Ensuring consumers benefit from efficiency (as required by the Tariff Order and other Victorian legislation) is an essential tenet of the regulatory regime implemented by ORG/ESC. Delivering these benefits to end-uses will require the ESC to demonstrate that it can deal with strategic behaviour and financial engineering by the DBs, both of which are perfectly legal.

Failure by the ESC to clearly explain what the efficiency benefits are, how much they are worth and to satisfy consumers that they will receive these benefits, would seriously undermine consumer support for the current form of regulating energy utilities. It appears from the *Issues Paper* that the ESC understands it faces this challenge. However, the *Position Paper* appears to focus on the ESC's concern about how best to ensure the profit incentives in the regulatory framework do not lead to long-term degradation of asset condition and service level. The *Position Paper* refers to concerns similar to those expressed by industry lobbyists such as '*the criticality of infrastructure investment*' and the risk to infrastructure investment '*arising from regulatory processes that may be too short term in their focus*.' These are real and legitimate concerns for consumers. The *Position Paper* seems to recognise that as it refers to the '*strong incentive on the part of the distributors to "talk up" future expenditure, and "talk down" future revenue'*.

It is clear the DBs are attempting to exercise strategic behaviour by ramping up their forecast costs way above levels they achieved over the last decade. They did the same thing in the electricity distribution price review in 2000 and it paid off.

It is absolutely essential for the ESC to demonstrate clearly that it can deliver a fair and reasonable outcome for both consumers and the DBs from this review.

The analysis presented in this report, which is consistent with information presented in the ESC's *Position Paper*, shows that:

- ORG's 2000 Decision (and subsequent Appeal) delivered between $75 and $150 million/year[23] in above benchmark revenue benefits to the DBs (that could possibly total $500-600 million by the end of the current regulatory period);
- an additional benefit of some $330 million was achieved through the same mechanism in the 1996-2000 period; and
- the total efficiency benefits captured by the DBs because their actual costs were below the level adopted by Government and ORG for (supposedly) efficient revenue building block cost benchmarks are, at least –

[23] All figures in June 2004 dollar values.

- $215 million in the 1996-2000 period for Opex costs alone (noting that Capex efficiency gains were possibly modest because the DBs invested more than forecast in the last 2 years of this period); and
- Opex efficiency gains of between $45 million and $60 million/year have been achieved in the first three years of the current regulatory period (ignoring any additional benefit accrued by AGL, Citipower/Powercor and United Energy through the related party arrangements identified by the ESC).
- Capex efficiency gains in the current regulatory period are more difficult to estimate, but an indicative figure would appear to be in the range of $10-20 million per year.

That is, cumulative benefits above efficient cost and efficient revenues that have been captured by the DBs since 1996 appear likely to exceed $1.3 billion (June 2004 dollars) by the end of the current regulatory period. This is equivalent to about 10% of the total cost of distribution services paid by consumers.

The ESC's *Position Paper* provides a preliminary indication of what this might mean in terms of tariff price impacts by stating:

> *If the Commission was simply to apply the framework and approach without any of the proposed step changes in expenditure for changes in functions and obligations and growth still under review, this analysis suggests the industry-average P_0 reduction would be more than 20 per cent..*[24]

That is, if ORG had approved revenue at levels that had matched the actuals, average distribution prices would have been '*more than 20 per cent'* lower.

The ORG/ESC efficiency carry-over mechanism implemented in 2001 allows efficiency benefits achieved in each year of the regulatory period to accrue to the DBs for a period of five years from the year achieved. Hence, a gain achieved in 2001 would not be passed on to consumers until 2006 and so on. This mechanism is meant to deliver all efficiency benefits to consumers after 5 years.[25] The ESC must ensure this happens – and is seen to happen.

ORG determined the efficient benchmark WACC was 6.8% (real, post-tax), yet the DBs have been consistently achieving out-turn Return on Regulated Assets above that level since 1996 (see the Table below taken from the ESC's latest Performance Report).

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[24] p12, *Electricity Distribution Price Review 2006-10 - Position Paper*, Essential Service Commission, March 2005.

[25] The explanation of this mechanism contained in ORG's 2000 Determination suggests that on a Net Present Value basis (adjusting for the "time value" of money to allow for the fact that the DBs gain their benefit before consumers do) the five year period results in a 30/70% split of efficiency gains between DBs and consumers respectively. This assumes, of course, that the ESC can demonstrate that consumers' share of the efficiency gain is not confiscated through DBs overstating cost forecasts for the next regulatory period.

TABLE 1: ACTUAL RETURN ON DISTRIBUTION ASSETS (%)

Actual return on distribution assets (%)								
DB	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
AGL	10.9	13.1	13.2	12.9	11.5	9.0	7.6	8.2
CitiPower	13.1	14.3	15.3	14.8	14.5	11.9	11.6	11.9
Powercor	12.0	13.5	13.9	16.3	16.2	8.7	10.3	11.2
TXU	13.0	13.6	15.0	15.6	14.4	8.7	9.2	10.6
United Energy	11.1	10.6	10.3	12.5	13.8	10.9	11.0	11.6

Despite cuts (that the DBs argued were severe) instituted by the ORG in 2000, the DBs' profitability remained well above efficient levels. When it is considered that the DBs are geared to significant levels, the actual return on distribution assets shown in the table below is quite high. A 50% increase in return for an entity geared to 60%, translates – as a preliminary estimate – into about a 150% increase in Return on Equity (or in the order of 20-25% *real*). It should be noted that the DBs do this by not investing in assets.

Consumer representatives who participated in 2000 electricity distribution price review are fully aware that the 6.8% WACC was acknowledged by ORG to be 'conservative' (that is generous to the DBs). It is acknowledged that application of the efficiency carryover mechanism will result in some increase in returns above the efficient benchmark WACC. However, the ESC should explain clearly and why consumers should not consider the substantial outperformance indicated above to be no more than extraction of monopoly rent.

4. Weighted Average Cost of Capital

The value of weighted average cost of capital (WACC) has a significant effect on the prices paid by consumers. This is because the costs associated with the recovery of capital, that is return on capital and return of capital (depreciation), comprises around 60% of the DB revenue cash flow.

Unfortunately, and inevitably, the importance of WACC to DBs' revenue provides strong incentives for ambit claims and exercise of strategic behaviour (i.e. gaming of the process, setting of parameters and associated information) by DBs.[26] Even more unfortunately for consumers is the fact that regulators show signs of being susceptible to the pressure exerted as part of the regulated businesses' strategic behaviour.[27] This susceptibility is demonstrated through regulators openly acknowledging that their decisions are 'cautious' or 'conservative' - meaning they deliberately set WACC values at the upper end of likely ranges estimated using (what have become in Australia) "standardised" approaches and analytical techniques.

In the case of Victorian DBs, a 10 basis point increase in WACC delivers around $6 million per year more revenue. The ESC's approach to determining WACC adds around 90 basis points ("Vanilla", real, post-tax) compared to judgements made by most other jurisdictional regulators; at a cost to consumers of around $54 million per year. This is a clear and very powerful incentive for the DBs to use every possible means to get the ESC to set higher values than necessary to satisfy the reasonable expectations of financial markets,[28] which should be a key benchmark for regulators.

Although regulators over time have tended to adopt more consistent (and sometimes more transparent) approaches to setting WACC, which is welcome, there are still inconsistencies, ambiguities and issues that remain or are poorly explained. The root of this observation lies in the method employed to estimate the WACC, which can only ever be approximate and dependent on considerable judgement.

WACC estimates require considerable judgment. For example, the Capital Asset Pricing Model (CAPM) used to estimate the cost of equity describes the relationship between expected risk and expected returns. Expectations cannot be measured but require judgment of those using the model. Further, although the CAPM is a generally accepted method for measuring the cost of equity it is one of many methods that could be used. No

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26 This behaviour is amply demonstrated by United Energy's 'sister company' Alinta Gas Networks (AGN). AGN recently lodged a proposal with the Economic Regulatory Authority in WA that argues ERA should follow the lead of Ofgem (and ESCoSA) and change the method for determining the Risk Free Rate because Government Bonds are currently at historically low levels.

There is a rational argument that using a 20 day average of Government bonds is not the best way to estimate a Risk Free Rate that is intended to be used to estimate a projected cost of debt over a five year period. But AGN's opportunism is narrow, selective, obvious and self interested. There is no mention in the AGN proposal that Ofgem also adopts a substantially lower Equity Risk Premium (MRP in Australia). Nor does AGN mention that it accrued substantial benefits over the previous five years because Government Bond rates fell by 150 Basis Points (presumably allowing AGN to benefit through lower borrowing costs).

27 There is also recent evidence from the UK that similar outcomes are occurring there.

28 The EUAA and EAG have experience with some 20 or so regulatory reviews, involving transmission and distribution in both electricity and gas. They have observed such tactics being used on a consistent basis with regulators all succumbing to some extent and resulting in higher prices for customers.

theoretical correct model exists to measure the cost of equity or indeed the WACC. With a considerable level of judgement involved in any WACC estimate it is extremely important that regulators balance the interests of utilities and consumers in setting WACC.

It is also clear that consumer input into regulatory reviews has been and remains inadequately resourced, especially compared to that of the DBs. This creates an asymmetry in the information and argument provided to regulators. Although regulators are aware of this imbalance, they nevertheless persist in setting inflated WACCs. It is clear that regulators are not well equipped to put themselves into the shoes of consumers. The perception raised by some that regulators do sympathise with consumers detracts from the credibility of the regulatory regime and gives regulated businesses more head room to challenge the regulators (with some beneficial outcomes for the businesses, it appears).

Our comment on WACC issues is structured as follows:

- first, we present a brief summary of the DBs' proposals;
- second, we discuss a number of fundamental issues related to the estimation of WACC for regulated utilities that is intended to assist the ESC and other Australian regulators in their determination of the WACC;
- third, we provide a benchmark comparison between UK and Australian regulators for different WACC decisions;
- forth, we provide some (technical) commentary on individual selected parameters referred to in the ESC's Issues Paper;
- fifth, we discuss the choice of Capital Asset Pricing Model (CAPM) model as the tool preferred by Australian regulators to estimate WACC components; and
- finally, we provide a conclusion and estimate the cost to consumers of the ESC's retention of a WACC value and input parameters proposed by the DBs, which we note are similar to those ORG adopted in the December 2000 Decision.

4.1. What the DBs want

The DBs' proposals for WACC are summarised by the ESC in Table 5.1 of the *Issues Paper*.[29] The DBs propose a minimum "Vanilla", real, post-tax WACC[30] of 6.7-6.8% (excluding a 'rural risk adjustment' proposed by Powercor).

WACC at the level proposed by the DBs is at the upper range of values endorsed by Australian regulators since 1998; and substantially above IPART's recent values of 5.0%

[29] p86-87, ESC Issues Paper.

[30] We note that terms and approaches used by different regulators for WACC are incomprehensibly confusing to consumers (and in some cases, it appears, even to the regulators themselves). We do not address each of the different approaches in this report. Suffice it to say that we fully endorse ORG's decision in 2000 to adopt what it calls the "Vanilla", real, post-tax WACC. This is the simplest approach used by regulators to estimate WACC and it allows the cost of tax to be treated separately and transparently in the revenue determination.

for water businesses and 6.0% for electricity distributors and a value of 5.1% recently proposed by the ESC for Victorian water businesses.

KPMG provided advice on WACC to the AGL, TXU (SPI) and United Energy. In summary, KPMG's advice is that:

- market risk premium (MRP), which is a key and still very contentious parameter used to estimate WACC, should be higher than 6.0% (8.0% seems favoured), although the DBs appear to have adopted 6.0% on the basis that this is almost universally preferred value of Australian regulators;
- equity beta, which is another key and equally contentious parameter used to estimate WACC, should be more than 1.0; and
- debt margin should be about the same as that adopted by ORG in 2000 (even though IPART recently adopted a BBB+ Commercial Debt instrument as a (lower) "benchmark" for efficient cost of debt for NSW DBs, and the ESC has indicated it may follow this "innovation" for the Victorian water utilities).

There is very little reference to, or analysis of, outcomes in the UK in the KPMG advice, or any clear recognition that all regulators (even those in Australia) consistently make the point that their judgements are 'cautious' and deliberately favour utilities (so as not to act as a disincentive to investment). Nor is there any comment on the outcomes from ORG's 2000 Determination, which delivered Return on Regulated Assets 50-100% higher than (what ORG argued at the time was) an efficient but 'conservative' estimate for the cost of capital.

The KPMG advice contains a summary of research reports dealing with the vagaries and challenges of estimating MRP and equity beta, but appears to make a one-sided presentation of the arguments. For example:

- In reference to MRP and international evidence, KPMG says that, "*In addition, we consider that the ESC should rely on Australian data on the MRP rather than data on other markets (e.g. the USA) given the structural and other differences between equity markets.*" But they present no direct evidence that identifies these "*structural and other differences*".[31]
- There is no comment at all on the UK experience with MRP values that place greater weight on market evidence than analysis of long-term historic data.
- KPMG refer to previous regulatory decisions in Australia if there is no other reason to justify a number that is higher than any reasonable interpretation of the evidence they quote.

Citipower/Powercor have taken a different line. Citipower/Powercor's principle argument is that regulators fail to satisfactorily deal with statistical variation of CAPM parameter data. This is literally correct – but hardly unbiased – given that regulators always come down on the side of 'conservative' judgements. It is correct that the regulators do not use statistical techniques to account for the impact of data variability. However, the regulators' judgements inevitably take account of doubt, variation and uncertainty in the data by selecting values that are higher than a simple average of all information available to them. Nor do Australian regulators place any weight on

[31] We refer to our discussion in section 4.4.1 on recent analysis of factors affecting the MRP.

information such as surveys of investor expectations that are given weight by UK regulators.

Again no mention is made of the UK experience, other than a quote from the ESC's 2002 Gas Distribution decision to the effect that we now have local data and do not need to look at UK precedents.[32] Given the continuing relative paucity of market data in Australia, consumers see clear reason to argue against the ESC accepting this line of argument.

Powercor/Citipower suggest a purely statistical approach (based on analysis of long-run historical data) and recommend setting all the parameter values at a figure established by (what appears to be) a 'confidence interval' of 70%. That means, more-or-less, that the ESC should be 'confident' that adopted values of CAPM parameters are higher than at least 70% of observed data.

The Powercor/Citipower submissions reproduce a diagram taken from a recent QCA Determination (see below), which shows the variation in MRP on an annual and 10 yearly moving average basis. This shows there has been significant volatility in MRP, which appears to have increased in the post-war years (for the annual average values), and since the late 1960s for the 10-year moving average - with extended periods when the 10-year moving average has been well below the longer term value commonly quoted by the DBs (of 6-8%). For example:

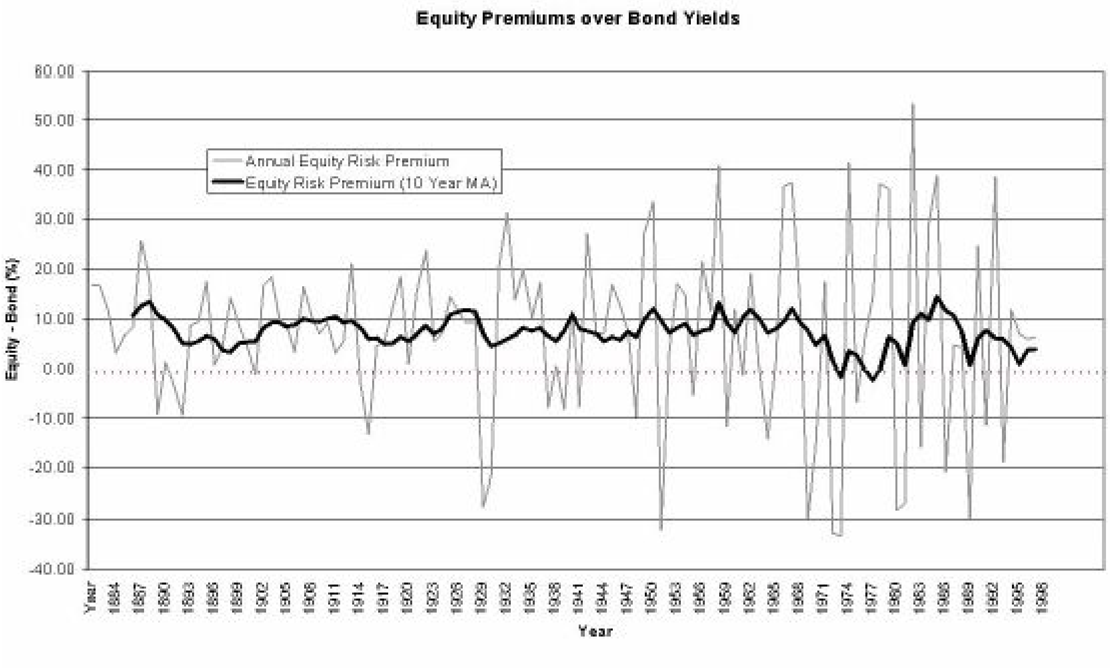
- During the early 1970s, the 10-year average MRP dropped below zero; and
- Since the late 1980s, the 10-year average has tended to stay below the 6-8% range.[33]

It is not entirely clear what this should mean to the ESC. However, it is clear that consistently adopting a Confidence Interval of 70% each regulatory period would, in the long term, ensure that consumers were paying well-above efficient levels of any reasonable value of the cost of capital.

[32] Ignoring overseas data and relying solely on local precedents will result in a circular problem in the setting of WACC. In effect, the inflated values used are far more likely to become "institutionalised" and perpetuated.

[33] A range of 6-8% based on historic data is consistent with analysis quoted by UK regulators – even though they adopt substantially lower value in their decisions.

FIGURE 4: ANNUAL AND 10 YEAR MOVING AVERAGE MRP IN AUSTRALIA



(Source: QCA, Proposed Access Arrangements for Gas Distribution Networks, October 2001, page 216)

It is also notable that major changes have occurred since the early 1970s that have impacted directly on Australian and international financial markets. In respect of KPMG's "*structural and other differences*" line of argument, the ESC would be aware that there are also very substantial similarities between Australian financial markets and related markets elsewhere. Not least of these is the impact on financial markets flowing from the tumultuous changes in oil prices (see below), which contributed to the Whitlam-era inflationary spike in Australia.

The relatively strong performance of the Australian economy over the last decade has, no doubt, been aided by fundamental changes to Australian financial market arrangements exemplified by floating of the Australian dollar in December 1983 and opening Australia's financial markets to participation by foreign banks in September 1987.

FIGURE 5: CRUDE OIL PRICES (US$2000/BARREL)

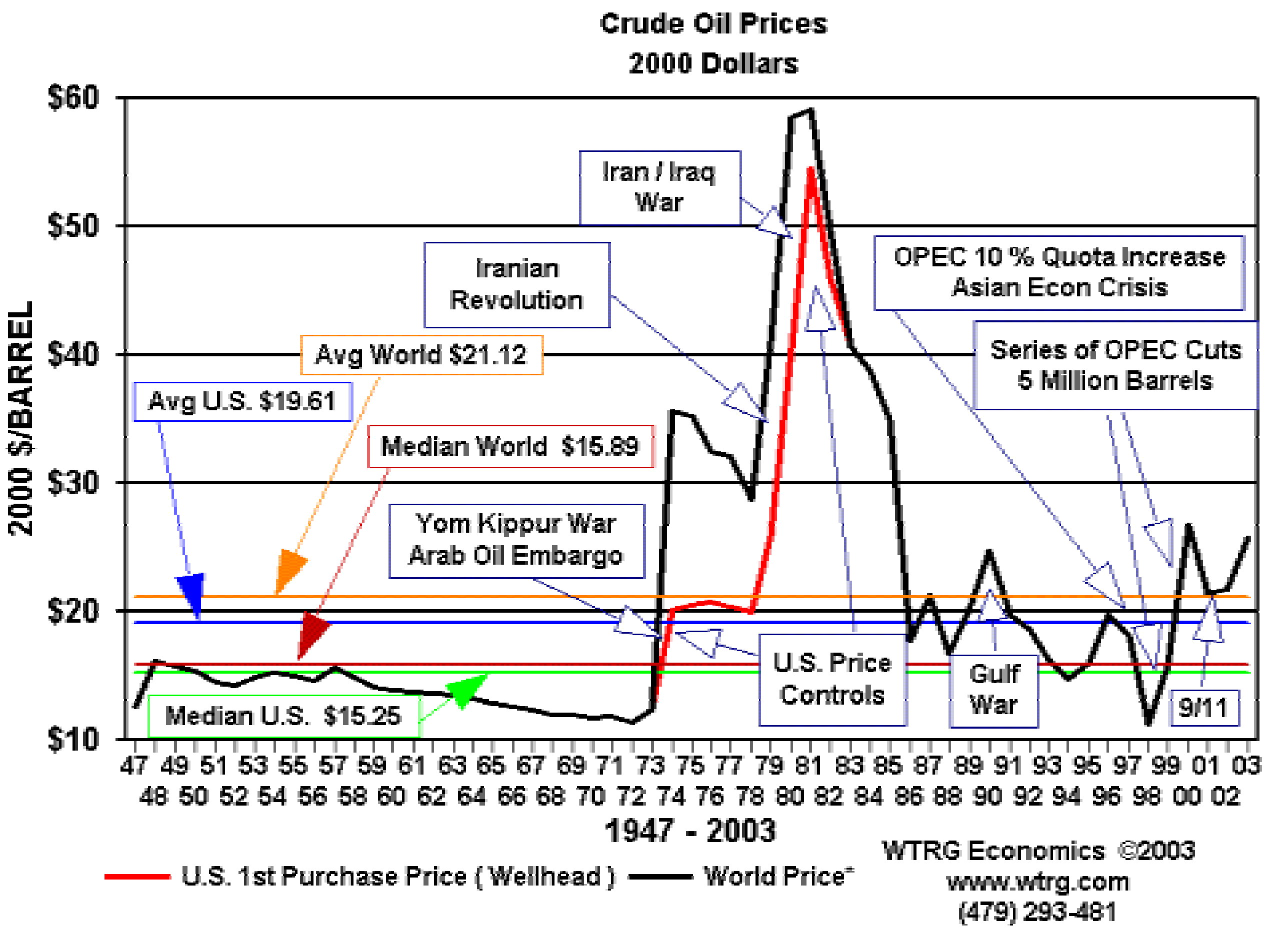
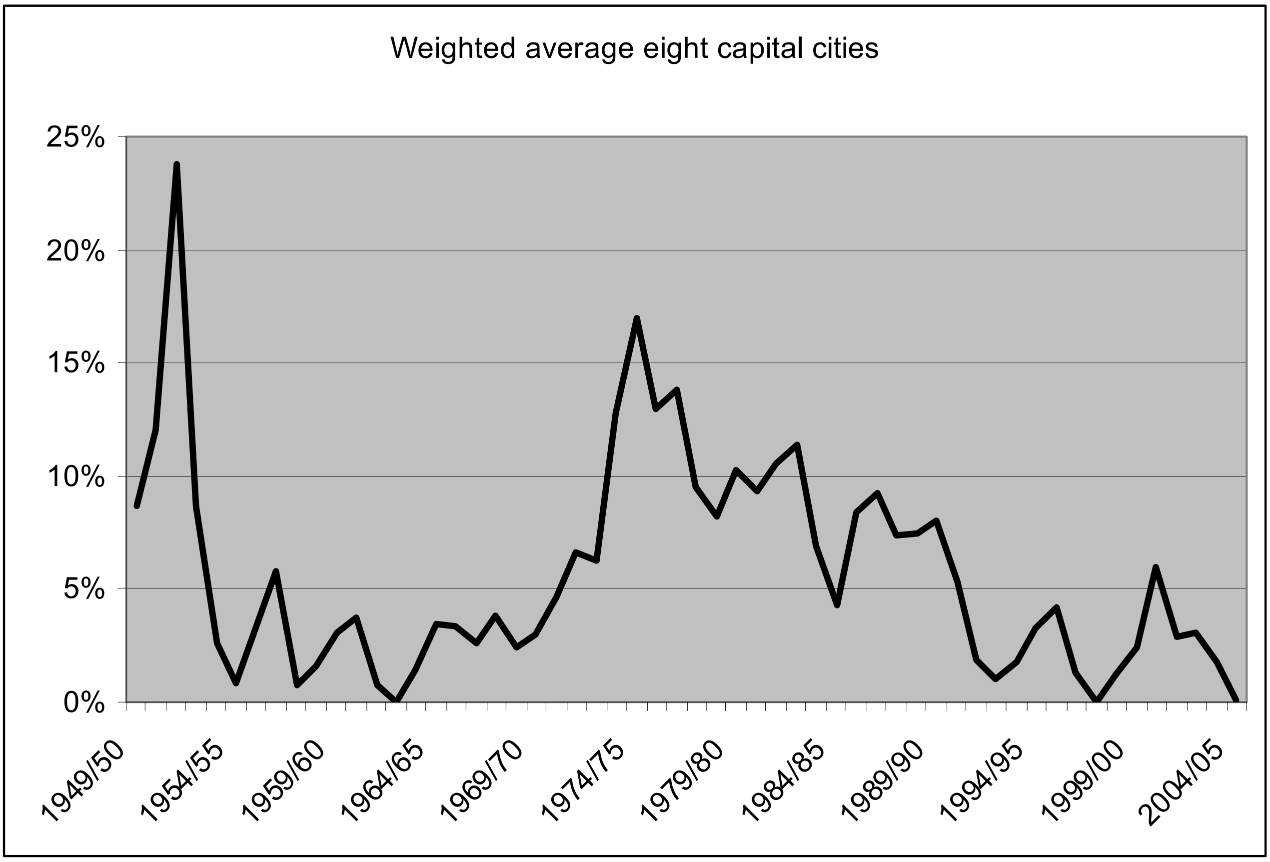


FIGURE 6: AUSTRALIAN INFLATION



The impact of these major changes in Australian financial markets strongly suggests it is inappropriate for regulators to assume that long-run historical data should be used as the basis for estimating values for either MRP or equity beta. Consideration of these factors argues in favour of placing greater weight on the view of financial market participants about their expectations than on analysis of long-run historical data.

If regulators were to use statistical analysis they would need to ensure that all (expected) inputs to the WACC formula were unbiased and did not contain any element of 'conservatism'. Further, depending on the statistical approach adopted, the regulator would likely need to expand on the number of assumptions (such as probability distributions and variances) already adopted in a CAPM framework. Accordingly, any statistical analysis would be inappropriate in the current context and only serve to decrease transparency in a process that already provides little confidence for consumers.

4.2. WACC and effective regulation

The main issues related to regulatory judgement on WACC remains the value of two key parameters required for application of the Capital Asset Pricing Model (CAPM) - the MRP and the equity beta. The value of both, and the way this value is established, is still subject to considerable debate. An essential platform in this debate has been noted by the Productivity Commission. In the report on the National Access Regime, the Productivity Commission argues that regulators should always err on the side of setting a higher

WACC because this provides a clear incentive for asset owners to continue investment in network infrastructure.[34]

While it is accepted that clear and consistent incentives are required to ensure ongoing investment, sufficient evidence exists to seriously question the Productivity Commission's conclusions. It is a fundamental requirement for regulators to undertake careful analysis and make considered, well-informed and independent decisions focussed on outcomes that emphasise broad economic benefits. Regualtors should steer away from making decisions that focus primarily on protecting the long-term interests of existing utility shareholders. This is particularly important in the context of setting a WACC for a regulated business, where there is considerable room for judgement in the final choice of value.

It is imperative that regulators form robust views on these matters and minimise bias in their judgements. This is becoming more-and-more possible with the now substantial track record of regulatory decisions in Australia (and elsewhere). Indeed virtually all regulators' decisions systematically discuss decisions by other Australian regulators, and use this discussion as a substantial basis for numerous aspects of their own decisions. It would seem that regulators have a capacity to follow an approach that makes it possible to refine the setting of WACC parameters and reduce the need for regulatory judgement (as well as regulatory risk). However, as discussed in the following sections, it is of concern that this is not the case.

Regulators should focus on the genuine long-term interests of consumers and adequately challenge monopoly service providers. 'Favouring' monopolists is poor regulatory practice. The monopolists will always pay themselves too much; much more so than most efficient competitive market service providers.

A fundamental purpose of effective regulation of monopolies is to deliver outcomes similar to those that would be delivered if effective competition were possible. It is axiomatic that, if competition is effective, successful firms manage to do three things:

- reduce all their costs, including financing and taxation costs, to a minimum sustainable level;
- provide services that consumers value; and
- allow consumers to capture benefits through prices that are related to the efficient cost of production (or supply) – at the same time as the quality of the goods and services provided is improved by ongoing investment in capacity.

If they can do these things, firms in competitive markets will be profitable, they will have satisfied customers and financial markets will voluntarily support them.

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[34] For example, see Box 13.1, p354, *Review of the National Access Regime – Inquiry Report*, Productivity Commission Report No 17, 28 September, 2001.

As this report shows, Australian regulators are already setting WACC at levels substantially higher than UK regulators. The ORG/ESC stands out as a regulator setting amongst the highest WACCs in Australia. It is unclear how the Productivity Commission's position should be interpreted. The Productivity Commission report contains very little analysis of comparative WACCs and bases its conclusions and recommendations more on rhetoric than fact.

The ESC has demonstrated its awareness that it has a key role and responsibility to ensure, as far as practicable, that similar outcomes are achieved through regulation of the electricity distribution sector in Victoria.

4.3. Benchmarking

The material below shows a 'benchmarking' comparison of return on equity, cost of debt and WACC.[35] The approach taken is to use values of CAPM parameters selected by individual regulators to derive estimates of real cost of debt, return on equity and the 'Vanilla' WACC.[36] This allows a (nearer) 'apples-for-apples' comparison of the outcomes from regulatory decisions than is possible by using numbers derived from different versions of CAPM, or by using nominal values that do not exclude the impact of inflation.

The 'Vanilla', real post-tax WACC has been chosen to 'normalise' this comparison because this has the simplest and most easily understood formula. The relative simplicity minimises confusion and provides a means for improving transparency surrounding most decisions on the WACC. Further, as mentioned above, this formula eliminates time dependant changes in inflation and avoids the need to allow for tax costs within the CAPM.

One of the principal advantages of using the 'Vanilla' WACC formula, which was clearly articulated by ORG in its 2000 Final Decision, is that regulators are then able to deal with the cost of tax transparently and directly by adding an additional line item for estimated tax costs to the Revenue Building Block.

It is acknowledged that these are 'noisy' diagrams that are difficult to interpret. That is, in a sense, one of their strengths.

The outcomes from regulators' deliberations on WACC values and the parameters used to estimate WACC are intended to reflect the costs of capital for efficient, well-managed firms – from the perspective of efficient financial markets.[37] It is clear that is the view that UK regulators take; and that view is consistent with the stated intent of the ORG/ESC is establishing 'efficient' costs for other components of the regulatory Revenue Building Blocks. If the WACC values do, in fact, reflect the cost of capital to efficient, well-

[35] Data in this form was first presented to the ACCC in 2002 on behalf of BHP-Billiton by Pareto Associates Pty Ltd. The data provided in this report has been updated by MJA to reflect the latest available information from regulatory decisions in the UK and Australia.

An earlier version of this information was presented to the ESC's gas distribution price review in 2002, but arguments supporting the conclusions drawn from this 'benchmarking' analysis have been refined since 2002. Accordingly, the ESC is urged to consider it carefully in this review.

[36] It should be noted that regulators almost universally adopt parameter values for estimating WACC, or final WACC values, that are above mid-range estimates quoted in their determinations. The basis of judgement for selecting a particular WACC value is sometimes not clearly explained in regulators' determinations, making it impossible to back-calculate a value for individual parameters that would yield the final WACC value. Therefore, the values shown on the diagrams below are likely to be somewhat lower than the regulator might have selected if the "Vanilla", real, post-tax formula had been applied using a single value for each CAPM/WACC parameter.

Where regulators quote a range of parameter values, a mid-point estimate of the "Vanilla", real, post-tax WACC has been estimated and shown on the diagrams in this paper (and in Appendix B).

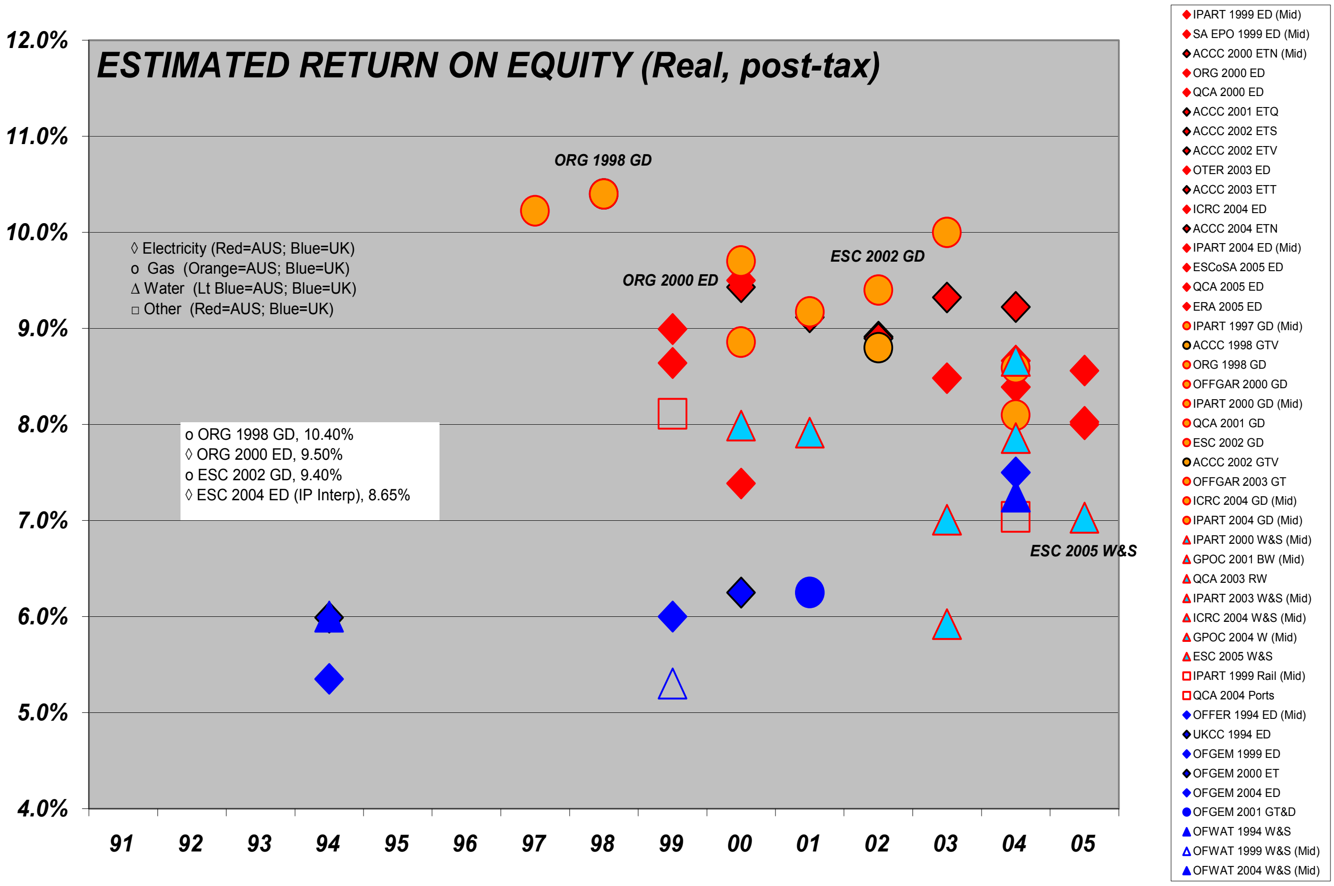
[37] Alternatively, the WACC might represent the cost of capital to efficient utility industry sectors.

managed, businesses, it would be expected that regulators would develop a consistent view of what constitutes the cost of capital. But that is not what these diagrams indicate for Australian regulators. As noted in more detail below, Australian regulators make more noticeably varied judgements on WACC for individual businesses in the same utility sectors and between utility sectors that their UK counterparts. It is this variability in outcome of regulators' decisions that creates the 'noise' (and difficult interpretation) that is so obvious.

4.3.1. Comparison of cost of equity

Figure 7 below shows values for the (real, post-tax) return on equity (cost of equity) estimated by reference to the judgements by Australian and UK regulators on values for the CAPM parameters for the range of decisions since 1994.[38]

FIGURE 7: ESTIMATED RETURN ON EQUITY (REAL, POST-TAX)



From 1994 to 2002 the values adopted by UK regulators can be seen to lie in a relatively narrow range of 5.2% to 6.2% (real, post-tax). More recently, however, the cost of equity allowed by UK regulators has increased significantly. The logic supporting this increase is most clearly articulated for the water sector, where the UK water regulator OFWAT

[38] The diagrams below all have the following common characteristics: ◊ = Electricity (Red=AUS; Blue=UK); o = Gas (Orange=AUS; Blue=UK); Δ = Water (Lt Blue=AUS; Blue=UK); □ = Other (Red=AUS; Blue=UK)

has stated that it has adopted a significant change in emphasis in key judgements related to the WACC. The most marked changes are:

- formal acknowledgement of a move away from reliance on the use of CAPM as the primary tool for estimating return on equity;
- greater reliance on information from, and views of, financial market analysts and observers about the expectations of debt and equity providers;
- acceptance of a view that financial market expectations have changed in that equity providers expect higher returns than in the recent past;
- a move away from adopting risk free rate parameter values based on direct observation of Gilt Bond rates, which are at historically low levels, that may be unsustainable over the next regulatory period; and
- reaffirmation that it is appropriate to extend 'size-premiums' to allow for higher cost of financing for the (relatively) smaller water-only companies.[39]

A manifestation of this changed view is acceptance of slightly higher values for the key WACC parameters for the risk free rate, market risk premium, equity beta and a wider range of 'size-premiums' for water-only companies than adopted in the 1999 Determinations. Nevertheless, similarity of view between different UK regulators on the cost of equity for utilities has been maintained – that extends to the rail, airports and communications sectors.

The similarity of view across industries and sectors observed in UK regulators' decisions is not a feature of Australian regulators' judgements on the value for parameters required to estimate the return on equity. In particular, the view taken by Australian regulators about the return on equity that is appropriate for energy and water utilities is markedly dissimilar to their UK counterparts.[40] As can be seen, there is far greater difference between Australian regulators' judgements on the cost of equity for different industries – even for the same sectors of the same industries – than is the case in the UK. For example:

- the CAPM parameter values adopted by QCA in 2004 and 2005 yield return on equity estimates from 6.59% for the water sector to 8.03% for electricity distributors;
- a noticeably more divergent difference is indicated in the ORG/ESC's decisions, with return on equity of 9.5% for electricity distributors in 2000, 9.4% for gas distributors in 2002, but only 7.0% for water utilities in its recent Draft Determination; and

[39] The ESC should note that the highest 'size premiums' apply to very small firms with regulated asset values of less than AU$170 million (£70m) – and no 'size premium' applies to firms with regulatory asset values of more than AU$1.7 billion (£700m). On that basis, arguments supporting application of a 'size premium' for small UK water-only companies is not translatable to regulation of energy utilities in Australia (or the UK for that matter).

[40] A possibly rational conclusion is that this divergence is directly related to the effectiveness of assertive 'strategic behaviour' exhibited by water sector protagonists in the UK and energy sector protagonists in Australia - both having conducted prolonged campaigns to 'convince' governments and regulators that greater 'investment incentives' are needed to ensure ongoing support by equity providers. This could be described as a form of well-orchestrated and 'institutionalised' monopoly behaviour.

- ESC's CAPM parameter values give an estimate for return on equity of 9.40% (2002) for gas distribution in Victoria, and ICRC's 8.59% (2004) for ACT; while IPART's values give 8.01% (2004) for NSW gas distribution.

We suggest the ESC address this issue by answering the following question:

Why should Victorian electricity consumers pay for a higher cost of capital than consumers in other jurisdictions, or pay for a higher cost of capital for electricity distribution than water consumers?

The ESC's commentary in its *Paper* sheds little light at all on this question, an answer to which is likely to improve the regulatory process and lead to more consistent decisions moving forward.

4.3.2. Comparison of the cost of debt

Figure 8 below shows values for the (real, pre-tax) cost of debt estimated by reference to the judgements by Australian and UK regulators for a range of decisions. The figure shows that real (pre-tax) values for the cost of debt generally lie within a band between 3.8 – 4.8% for both UK and Australian utilities, across sectors. It is notable that estimates accepted by ORG/ESC and QCA in 2000 (and more recently ESCoSA) are higher than those accepted by other Australian regulators. It is also notable that both ERA and QCA have recently accepted cost of debt values that reflect historically low Government Bond rates. By contrast, ESCoSA responded to pressure from ETSA utilities in 2004 and adopted a fundamentally different approach to that used by other Australian regulators for establishing the risk free, which yielded a substantially higher estimate for the cost of debt.[41]

This data shows that UK regulators generally adopt slightly lower values for the cost of debt than Australian regulators for the same industry sector which is related (primarily) to differences in the price of Government Bonds that have a substantial influence on selection of a risk free rate. However, there is generally greater difference between Australian regulators. This is partly because:

- of significant fluctuations in Australia's Commonwealth Treasury Bond rates (that are not 'ironed out' by adopting a more volatile 20 day moving average as the 'proxy' for what is effectively a 5-year forecast);[42] and
- Australian regulators adopt different approaches for estimating debt margins and some have 'tinkered' with debt margins that they acknowledge are already 'cautious' and 'conservative' (i.e. favour regulated utilities) by adding incremental amounts for 'debt financing cost' and 'cost of debt hedge timing'.

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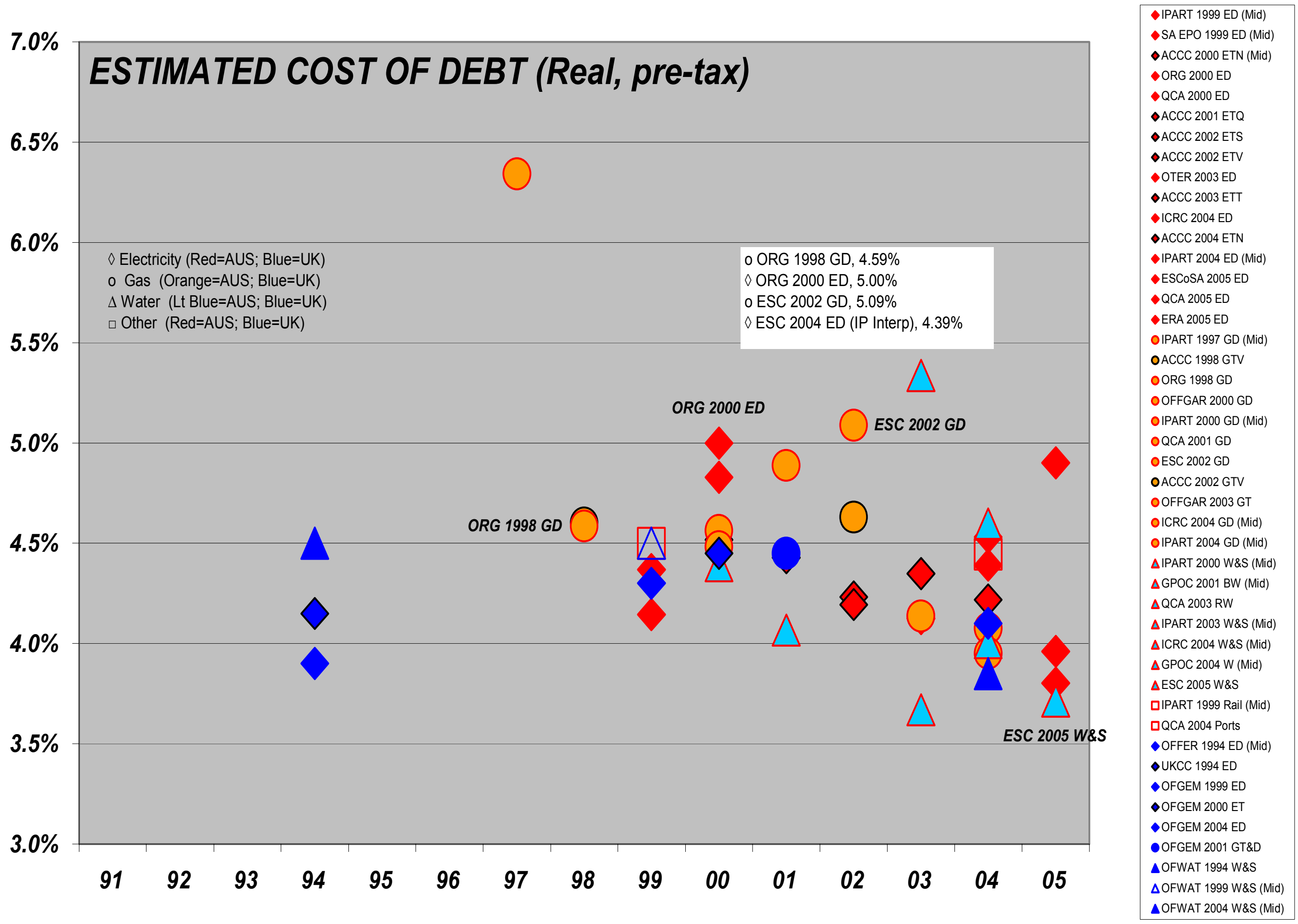
[41] Most Australian regulators, including the ESC, use the average of the Government Bond rate in the 20 days preceding their Determinations to establish the risk free rate. ESCoSA adopted a 5 year average in response to ETSA Utilities assertion that Government Bonds were at historical low levels that were unlikely to be maintained during the coming regulatory period.

While ETSA Utilities assertion is correct, it is beyond doubt that ETSA Utilities argued this case because it would be better off than if ESCoSA followed precedents set by other Australian regulators.

[42] This matter is discussed in further detail later in this submission.

FIGURE 8: ESTIMATED COST OF DEBT, REAL PRE-TAX



It appears clear that Australian regulators should adopt a more consistent and pragmatic approach in estimating the cost of debt. Clearly it is inconsistent to calculate an 'accurate' value for the risk free rate (by using a 20-day average that is demonstrably volatile), then adopt a basic debt margin and various 'add-ons' that are 'cautious' and/or 'conservative' – and not directly related to efficient, observable cost of debt for regulated entities. Nor should regulators assign a cost of debt that suits an individual regulated entity, or precisely matches the actual cost of debt incurred by the regulated entity, because this would be inconsistent with a principle of 'incentive' regulation.

Ideally, regulators – including the ESC – should adopt a 'benchmark' cost of debt that is 'efficient' but still provides an incentive for 'efficient, well-managed' utilities to lower their financing cost. The 'benchmark' should provide a challenge that forces less-efficient and less well-managed utilities (i.e. those with financing cost above the 'benchmark') to 'lift their game. It is axiomatic that regulators should also then develop a longer-term mechanism to transfer the financing 'efficiency gain' to consumers through progressively lowering cost of debt so that it matches a truly 'efficient benchmark'.

4.3.3. Comparison of Vanilla WACCs

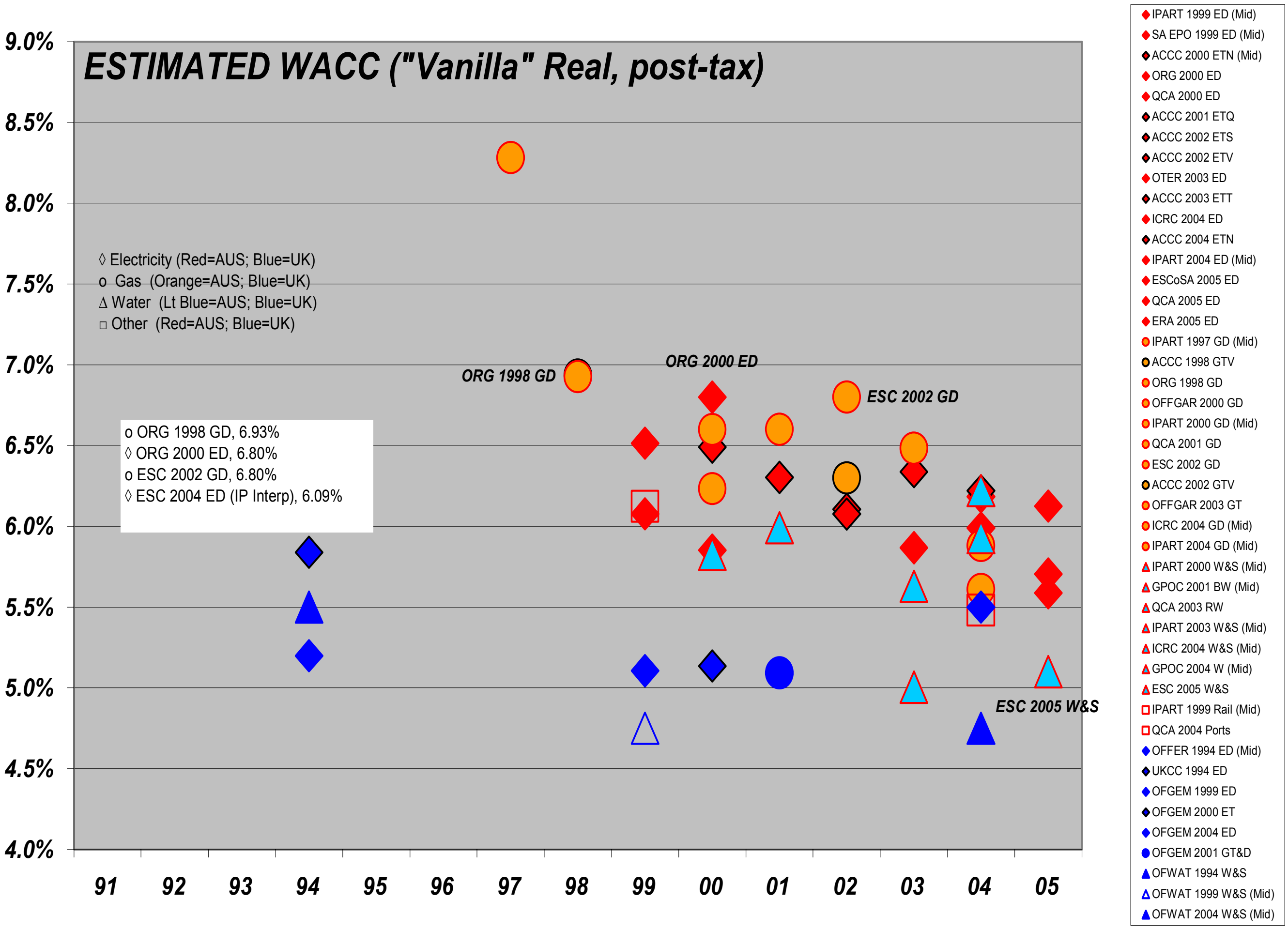
The figure below compares regulatory decisions using the real, post-tax 'Vanilla' WACC. The figure clearly shows that Australian regulators have made judgements that result in

WACC values that are far more varied than those made by UK regulators administering similar incentive regulation regimes.

With regard to the ESC it is noted that:

- it continues to adopt the highest value WACC in Australia for electricity (and gas) distribution, with values ranging from 60-120 basis points higher than other jurisdictional regulators (an average of 90 basis points); and
- it has recently indicated it proposes a lower value of WACC of 5.1% for the water sector.

FIGURE 9: ESTIMATED "VANILLA", POST-TAX WACC



Interestingly, it would seem there is a downward trend in the WACC decisions taken by Australian regulators over the last few years. However, only one observation is available for 2005. It is therefore possible that Australian regulators are responding to legitimate consumer concerns and gradually lowering WACC to bring it closer to values assigned by UK regulators.

The analysis also shows Australian regulators have generally endorsed outcomes that, unfortunately for consumers, ensure Australia's energy networks will be less 'efficient' (i.e. more costly to consumers) than in the UK. This is not a desirable outcome for customers, especially those operating in competitive world markets.

It is therefore suggested that the ESC answer the following question:

What are the differences between the UK and Australia that justify the assumption that investors' expectations differ? OR: Why is a Market Risk Premium of no more than 5% accepted by UK utility investors, when Australian regulators judge Australian utility investors expect 6%?

While some of the difference may be explained by differences in approach, as discussed in section 4.4.1 below, the is no clear evidence that international financial markets see Australian utilities as less efficient and more costly to finance than their UK (and US) counterparts. For reasons that have never been adequately and transparently explained, regulators persist with decisions that suggest the opposite. That is, regulators are out of tune with financial markets.

4.4. Individual Parameters

Australian regulators and regulated businesses put substantial effort into arguing for particular values of individual parameters in the CAPM and WACC formulae. However, it is clear that the value adopted by regulators for individual CAPM parameters is not as important as the final value of WACC that the parameter values yield. Ultimately, the value of any individual parameter, be it the market risk premium (MRP) or equity beta, is only meaningful if the final value of WACC produced by the CAPM formulae can be demonstrated to be fair and reasonable to both utility owners and consumers.

Nevertheless, estimation of the WACC according to the methodology universally adopted by Australian regulators requires consideration of the individual parameters. In this respect, a major concern is that the approach used by ESC (and all other Australian) regulators appears mechanistic and tends to focus on analysis of historical data in determining values for individual CAPM parameters.

Further, the mechanistic approach where regulators follow the decisions made by one another is more prone to perpetuating mistakes and diminishes the value of other evidence available to regulators, such as the informed judgement of independent financial market analysts which, for example, is typically given greater weight by UK regulators.[43]

In this context, it is noted that financial markets have been willing to continue to fund energy networks in Australia and that financial market commentators have repeatedly commented without undue concern about the impact on regulated utilities of regulators' decisions.

The section below focus on the following individual parameters:

- the market risk premium (MRP);
- the risk free rate; and

[43] It is notable that OFWAT has formally acknowledged (in its recent Determination) that it has moved away from reliance on CAPM to underpin judgements on WACC, and places greater weight on information and observations obtain from financial market analysts and practitioners.

- equity beta.

4.4.1. Market Risk Premium

Of all the components of the WACC, the magnitude of the MRP attracts most disagreement by practitioners and academics alike. Although ORG/ESC has previously considered the merit of alternative bases and methods for deriving a value for the premium, it is of concern that the current choice of 6% remains higher than it need be (to satisfy the reasonable expectations of financial markets).

A primary concern is that reliance on historical approaches to calculating the MRP is likely to provide estimates that are too high. Investors care about expected returns, not historic returns. The market risk premium therefore should be estimated on a forward-looking basis. Evidence from forward-looking studies almost universally show estimates, on average, that are lower than that determined by arithmetic and statistical analysis of historic data.

In addition, historical estimates differ considerably depending on the averaging technique and time period used. The arithmetic mean is typically around two percentage points higher than the geometric mean, depending on volatility and time period.[44] The statistical nature of the problem is such that an arithmetic average is likely to overestimate the MRP. While it is beyond the scope of this paper (and resources allocated to consumers for participation in the ESC review) to address this issue, the ESC is urged to examine this issue more closely.

Historic returns are often used as a proxy for the expected forward-looking returns, which is what CAPM is supposed to estimate. The main problem is that historic data cannot measure the expectations of investors and historic data is therefore inconsistent with the theoretical underpinnings of the CAPM. In particular, it is noted that Wright, Mason and Miles (2003) say:[45]

> *"It is evident that even over quite long periods, realised returns need not provide any relation to the expected premium. If they did, the experience of the bull market of the 1990s would have implied a risk premium of equities over cash of around 15%, switching to a large negative risk premium in the subsequent bear market of the early years of the new millennium. This would be manifestly absurd. There is no evidence that rational investors were expecting to receive such returns in advance."*

Further, there are reasons to believe the historic approach overestimates the return required by investors:[46]

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[44] See e.g. Wright, Mason and Miles (2003), *A study into certain aspects of the cost of capital for regulated utilities in the U.K.*, p 4.

[45] Wright, Mason and Miles (2003), *A study into certain aspects of the cost of capital for regulated utilities in the U.K.*, p 22. This report was commissioned by the UK economic regulators and the Office of Fair Trading in order to gain an independent view on emerging and new issues in the estimation of the cost of capital, the scope for greater consistency between regulators and to understand why there may be differences in approach.

[46] For a comprehensive overview of factors affecting the Australian MRP, see Allen Consulting Group (2004), *Review of Studies Comparing International Regulatory Determinations*, Report for the ACCC, March.

- ex-post historical studies may be based on long time periods, but capital markets have changed substantially since 1900 and 1930 – and particularly in the past two decades. Financial markets have been liberalised, the Australian dollar floated, capital markets around the world have become less segmented and more integrated with world markets and the scope to diversify has increased substantially;[47] and
- a downward shift in the MRP may be caused by improved regulatory and legal infrastructures that protect investors, by lower trading costs and by improved market liquidity.[48]

The ESC should therefore exercise care when using historical estimates as representative of the current or recent situation, as they are likely to overestimate the MRP.[49]

Due to the perceived difficulties associated with collecting reliable prospective estimates of the MRP, regulators have typically based their assessment on analysis of historic data. However, the prospective approach is supported by several prominent economic experts, for example Siegel (1992)[50], Jenkinson (1993)[51] and Blanchard (1993)[52]. Further, as a result of the concerns about the validity of ex-post realised returns as an indicator of future expectations, there has also been a general trend amongst UK regulators in recent years to adopt more forward looking approaches to estimating the MRP. In particular, we note that OFWAT and OFGEM are not the only UK regulators to consider both historical and prospective evidence:[53]

> *"In deciding the appropriate value for the equity premium, Oftel has taken account a range of evidence, both historical and forward-looking. Oftel's judgement reflects its recognition of the need to balance both short and long run interests of consumers."*

The choices available to regulators are thus:

- to use a 'firmly estimated' but inappropriate historical measure;
- to use the 'less firm' measure, but appropriate forward-looking concept; or
- to interpret the range of estimates based on the inappropriate measure in the light of the insights from the forward looking results.

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[47] See e.g. Ragunathan, V. (1999), *The effect of financial deregulation on Integration: An Australian Perspective,* Journal of Economics and Business, 51, pp 505-674.

[48] A more complete list of factors is provided by AMP Henderson (2003), *The equity risk premium – what is it and is it enough?* p 2-3.

[49] Further, the prospective method requires an assessment of expectation of the future equity market return and is calculated by subtracting the risk free rate from the expected future market return. As such, it can overcome the problem of consistency between the risk free rate and MRP.

[50] Siegel, J.J., (1992), *The Equity Premium: Stock and Bond returns since 1802*, Financial Analysts Journal, Jan/Feb.

[51] Jenkinson, T. (1993), *The Cost of Equity Finance: Conventional Wisdom Reconsidered*, Stock Exchange Quarterly, Autumn.

[52] Blanchard, O.J., (1993), *Movements in the Equity Risk Premium*, Brookings Papers on Economic Activity, Vol. 2.

[53] OFTEL (2001), *Proposals for network charge and retail price controls*, Annex E, paragraph E.13, February.

A truly prospective and forward-looking approach should be favoured. The second best solution, which is adopted by all UK regulators, is to explicitly place greater weight on the available forward-looking estimates when deciding upon a range of values for the MRP.

Based on the recent evidence provided by Allen Consulting Group[54] and Professor Martin Lally[55], it can be suggested that the ESC could 'safely' reduce its estimate of the MRP from 6% to 5% without disrupting the legitimate expectations of efficient financial markets.[56, 57] But this is not sufficient justification for imposing high and inefficient costs onto consumers.

The solution for investors whose expectations exceed those of efficient financial markets is to modify their expectations or transfer ownership of assets to investors whose expectations represent those of efficient financial markets. If the DB owners are not prepared to transfer ownership of assets to 'efficient' investors, then they should be prepared to accept the same returns as 'efficient' investors. The ESC should not overreact to pressure from businesses with a clear vested interest and seek to satisfy any investor whose expectations exceed those of efficient financial markets. This would be counter to, and inimical to, the intent of incentive-based regulation and good regulatory practice.

4.4.2. Risk-free rate

It is also of concern with Australian regulators reject the use of a 5-year maturity government bond to establish an estimate for the risk free rate. This is particularly surprising given the very clear recommendations provided by Lally (2004)[58] to the QCA, and the QCA's own belief that "*there is strong case for setting the risk-free rate using a bond-term equal to the length of the regulatory cycle*".[59]

The QCA reasons that the 10-year bond is appropriate because it is consistent with standard commercial and regulatory practise (established by the ORG/ESC) and broadly supported by stakeholders. This is distressingly similar to previous arguments put by other regulators. This line of argument is symptomatic of the mechanistic and conservative (i.e. overly protective of regulated monopolies' interests) regulatory approach taken by almost all Australian regulators.

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54 See Allen Consulting Group (2004), Review of Studies Comparing International Regulatory Determinations, Report for the ACCC, March and Allen Consulting Group (2004), *Queensland DBs: Cost of Capital Study*, A report to QCA, December.

55 Lally (2004), *The Cost of Capital for Regulated Entities*, Report prepared for the QCA, October.

56 It is noted that both ACG and Lally recommend a MRP of 6%. Nevertheless, interpretation of the data provided, and weighting towards a forward looking approach to the estimation of the MRP, leads to a conclusion that 5% would be a reasonable estimate.

57 It is recognised that individual asset owners may express dissatisfaction with such a move. Epic Energy's reaction to the West Australian energy regulator's attempt to establish a regulated price path for the Dampier to Bunbury gas pipeline within reasonable proximity of an efficient cost base shows how strongly a dissatisfied investor may react.

58 Lally (2004), *The Cost of Capital for Regulated Entities*, Report prepared for the QCA, October.

59 QCA(2004), *Regulation of Electricity Distribution,* Draft Determination, December, p 89.

Clearly, the most appropriate maturity to be selected is the 5-year government bond. Simply because other Australian regulators have applied a 10-year maturity, or because it is supported by regulated utilities, does not justify an approach that is clearly wrong. A regular 5-yearly review of the DBs' revenue requirement lowers the financing risk and ensures the DBS will be able to finance assets with long lives.

The infrastructure necessary to support the provision of energy services is a long-term investment and a long-term investor in that infrastructure has a legitimate commercial interest to receive adequate compensation for the risks that it bears. The process of regular regulatory reviews effectively transfers to risks associated with efficient investment from shareholders to consumers. Accordingly, there is no legitimate commercial interest in being compensated for risks which, as a result of the regulatory scheme (or contract), are shifted on to others – specifically consumers. It is therefore considered appropriate to adopt a five-year maturity as the maximum and appropriate maturity for the risk free rate.

With regard to yields, theory predicts that current yields will reflect (all) expectations of future earnings (if capital markets are efficient). Theoretically, it would therefore be appropriate to select the most current yield.

However, current yields can be significantly affected by market influences in the short term (e.g. thin trading) and be prone to significant cyclical variations. It is therefore worthwhile to review the historical yields as these may be better predictors of future yields than current yields. In our view, the current 20-day averaging period used by the majority of Australian regulators, including the ESC, simply does not accord to such principles. For example, over the last 2 years the 20-day moving average for indexed Commonwealth Treasury Bonds has varied by nearly 100 basis points; and even over short periods of several months, the 20-day moving average has fluctuated by 30 or more basis points. This volatility has a significant effect on the estimated cost of debt that is unrelated to financing costs for regulated utilities. It is notable that UK regulators minimise this effect by taking a less 'scientific' approach and not 'calculating' a specific value for the risk free rate. Instead, UK regulators place greater reliance on information and advice sourced from financial market practitioners.

Hence, it is recommended that the ESC review how yields have fluctuated during the past few years and consider the implications of any abnormalities in the daily yields for the time period being considered that may lead to atypical results. The ESC will also need to consider the implications for consumers of changing the basis for establishing the risk free rate. It is clear that the DBs will have benefited over the current regulatory period because Government Bond rates, and interest rates, have been markedly lower that anticipated by the ORG in 2000. A simple mechanism to transfer these gains to consumers is to maintain consistency in the method of establishing the risk free rate.

4.4.3. Equity Beta

The equity beta quantifies the relative risk to shareholders in the particular company, or project, that reflects both the underlying risk of the project and the risk to shareholders as a result of the – preferential claims of debt holders resulting from having leveraged the balance sheet.

Australian regulators generally rely on the recommendations of consultants in forming judgement on the equity beta. Allen Consulting Group has provided advice to the majority of Australian regulators on this matter. However, there are a number of concerns with the ACG approach and its conclusions, most recently articulated in its report to QCA:

- Based on a comparison with US data, ACG conclude that the equity beta would be in the range between 0.23 – 0.69. By removing 'bubble' data, ACG conclude that a current equity beta value is around 0.8.

  While the importance of eliminating the 'bubble' period is acknowledged, a simple method of doing this would be to rely on weekly observations instead of monthly observations that by definition require longer time series. By increasing the frequency of observations, the number of observations also increases, thereby reducing the variance/uncertainty of the estimate.[60] That is, beta could be estimated on the basis of weekly (or even daily) observations using a short time period of say 1-2 years.

- ACG make no comparisons at all with UK regulatory decisions. This is surprising since the UK and Australia have similar regulatory regimes – and the vast majority of US jurisdictions still use 'rate-of-return/cost-of-service' regimes that would breach the National Electricity Code or Victorian Electricity Supply Industry Tariff Order if applied in by a regulator (and which deal with investment risk in fundamentally different ways to UK and Australian regulatory regimes).[61] In this regard, it is noted that in its most recent decision, OFGEM has decided that an equity beta value of 0.8 is appropriate.[62]

- Without any adjustments for differing risk characteristics, ACG postulate an equity beta of 1.00, although its evidence would suggest a lower beta value. In the case of its recommendations to QCA, this value is then adjusted by 0.1 to take account of specific risk characteristics facing Queensland DBs (by contrast, in recent advice to the Economic Regulatory Authority of WA, ACG recommends an equity beta value of 1.0 simply because this is the value adopted by the majority of Australian regulators). Virtually all Australian regulators, including the ESC, acknowledge that evidence suggests an equity beta significantly lower than 1.0.

- We also note that ACG conclude that, "*we would not expect the equity beta to be lower than that of say, metropolitan water distribution companies whose demand is largely dependant on weather conditions*".[63]

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[60] However, it also increases the risk of serial correlation. Serial correlation of returns may be explained by either overreaction by the market (giving rise to negative correlation), or rigidity (giving rise to negative correlation).

[61] The US-style 'rate-of-return' schemes typically provide both an upper-bound and lower-bound cap of equity returns, whereas the UK-style 'incentive' regimes provide opportunities for prudent, efficient and well-managed firms to exceed the WACC benchmark. It is also noted that regulators administering UK-style regimes have a key role in protecting the interests of consumers by not protecting imprudent, inefficient or poorly-managed firms. Knowledge that regulators will not intervene to protect poor performers is a powerful incentive for utility owners to insist on good performance by utility managers.

[62] *Electricity Distribution Price Control Review - Final Proposals*, OFGEM, November 2004 (Note CAPM parameter values generally not quoted). See also Table 1, p.28, *Electricity Distribution Price Control Review. Background information on the cost of capital*, OFGEM, March 2004.

[63] *Queensland DBs: Cost of Capital Study*, Allen Consulting Group report to QCA, December 2004.

> It is also noted that no Australian regulator has adopted a value for equity beta for the water sector above 0.9, with the lowest at just 0.4 – and the average shown for the Australian regulatory decisions in Appendix B of 0.73. Nor does it escape attention that the ESC only recently adopted an equity beta value of 0.75 for Victorian water businesses. There appears to be no clear argument why a higher value is either appropriate or suitable for application to energy utilities.

In summary, there is no convincing evidence that a value of 1.0 is appropriate for the DBs. This is an overly conservative estimate and a lower value should be adopted. Indeed, it is suggested that the ESC answer the following question:

What are the similarities between monopoly utilities and firms in competitive markets that support the judgement that non-diversifiable risk faced by those utilities is exactly the same as the financial market as a whole? OR: Why should Equity Beta value be set at (or near) 1.0 for monopoly utilities that provide what are effectively price-inelastic "essential services" that consumers literally cannot do without or get elsewhere?

A first principle evaluation of the risks faced by the DBs is likely to reveal that the equity beta values are lower than 1.0. Indeed, evidence suggests values no higher than 0.7 – 0.9 to be reasonable. As such, it is suggested that the ESC adopt an equity beta of no more than 0.8, or around the same value adopted for regulation of the water sector.

4.5. Choice of Model

Virtually every Australian regulator has its own preferred CAPM model. The ESC uses what it calls the "Vanilla", real, post-tax version. QCA uses what it calls the "Officer WACC3" CAPM to determine WACC. IPART, ICRC, ESCoSA, ERA and OTER all continue to use the much more complex pre-tax version. It is noted that the "Officer WACC3" model is very similar to the "Vanilla" version of CAPM adopted by ORG in 2000 and used to 'benchmark' WACC in the section above.

It is common for Australian regulators to rely on domestic closed economy versions of the CAPM, even though it is widely recognised that the Australian economy is open and increasingly so. With regard to capital integration, the change from a segmentation to an integration approach to estimating WACC has been examined by Jorion and Schwartz (1986)[64] for Canada and by Ragunathan (1999)[65] and Ragunathan et al (2000)[66] for Australia.

Betas and MRPs must be defined against the market to which they apply. Importantly, both the betas and MRPs change as markets become more integrated and investors are able to diversify more and more.

[64] Jorion, P. and E. Schwartz, (1986) *Integration vs. Segmentation in the Canadian Stock Market*, Journal of Finance, 41, pp. 603-616.

[65] Ragunathan, V. (1999), *The Effect of Financial Deregulation on Integration: An Australian Perspective*, Journal of Economics and Business, 51, pp. 505-674.

[66] Ragunathan, V., Faff, R. W., and Brooks, R.D., (2000), *Australian industry beta risk, the choice of market index and business cycles*, Applied Financial Economics, 10.

Econometric analysis by Ragunathan et al (2000)[67] finds that Australian betas are best explained when the influence of both Australian and US market portfolios are recognised.

An appropriate method of responding to the concern that Australian estimates of the MRP may be invalidated by the step change from a segmented capital market to a more integrated international capital market would be to:

- rely on forward looking estimates of the Australian MRP. By definition these are free of the step change which occurred with the float of the Australian dollar and financial market deregulation. This approach would allow the segmented CAPM model to continue to be applied but would avoid any concerns with estimate bias due to greater integration; or
- recognise that capital markets have become increasingly integrated and adopt an integrated/international CAPM approach in conjunction with a segmented approach.

The first option would result in a reduction of the estimates of the MRP (as discussed in section 4.4.1)

The second option is likely to result in significantly lower estimates of the appropriate MRP, beta and therefore the WACC.

While the use of an international CAPM potentially would increase complexity and reduce reliability, this in itself should not imply that insights from the international model should not be used in the regulatory process. It would serve to illustrate an important point: that recognition of the consequences of capital market integration will result in a WACC that is lower than currently suggested by Australian regulators.

Since the world portfolio offers opportunities to diversify across economies, the variance of the world portfolio is less than the domestic portfolio. As a result, the world MRP is lower than the Australian MRP. Lally (2000) calculates that the world MRP of 3.5% is appropriate.[68]

4.6. Conclusion

The benchmark material presented above provides a comparison of estimates for the cost of debt and the return on equity indicated by decisions of regulators in the UK and Australia. These estimates have been derived using values judged by each regulator as being appropriate for individual parameters required for use of the simple, "Vanilla", real, post-tax form of the CAPM (noting that the individual parameters, and the values assigned to them, are the same in each version of CAPM – unless account is taken of the degree of market integration/segregation). All estimates are expressed in common 'apples-for-apples' real, post-tax terms.

Analysis of this material clearly shows that Australian regulators historically have accepted a significantly lesser difference in the cost of debt (in real terms) between the UK and Australia than is the case for cost of equity (or return on equity). That is, the

67 Ibid p 49

68 Lally, M (2000) *The Real Cost of Capital in New Zealand: Is it too high?*, October.

judgement of Australian regulators is that the debt market sees a (very much) smaller difference between Australian and UK utilities than does the equity market. This judgement may be sound, but the magnitude of the difference - and the spread of values for estimated return on equity by Australian regulators - is substantial. While this difference has not been adequately explained in regulatory decisions, recent evidence from the UK suggests that differences between the countries may, in fact, be narrowing.

While this latest evidence is encouraging, as international financial markets would be expected to see similar regulated utilities in consistent terms, the latest determinations from the UK also suggest that changes have been influenced by relentless lobbying of utilities rather than an underlying change in financial market fundamentals. As such, it is noteworthy that the 1994 and 1999 decisions by OFWAT were subject to appeal, while the 2004 determination was not, which suggests the UK water industry was well satisfied with the outcome.

It is clear that the dominant 'regulatory principle' governing the treatment of WACC should be that the return on equity and cost of capital be set at levels that meet the reasonable 'efficient' expectations of financial markets – rather than individual investors. This is what is intended by the regulatory regime and the only way that consumers can access the benefits of 'efficient' financing of prudent, well-managed companies by providers of capital whose expectations are reasonable. On the other hand, continuing to set WACC values that are inflated and biased in favour of utilities holds out no prospect of consumers being able to share in efficiency benefits through incentive regulation, as required by the Tariff Order and Victorian legislation under which the ESC regulates electricity distribution.

It is accepted that the ESC's regulatory decision is likely to be based on a wide range of information – and that the ESC will attempt to promote 'regulatory consistency' as a desirable goal. However, it is of concern that insufficient attention will be paid by the ESC to evidence from the UK. Further, it seems that the 'principle' of regulatory consistency prevails over the need to arrive at fair and reasonable judgements based on the best available information. An example is the choice of a 10-year maturity of the risk-free rate that QCA clearly recognises is inappropriate.

The major cause of the differences between estimates for the cost of equity between the UK and Australian regulatory judgements seems to be that Australian regulators have accepted higher values for the MRP than do UK regulators; and higher - and much more varied - values of equity beta.

In general, Australian regulators have relied on historical evidence to determine the MRP. However, in addition to being inconsistent with approaches that seek to access forward-looking information to estimate the cost of capital, historical analysis will bias the estimate of the MRP upwards due to the fundamental changes to the financial markets during the past 50 years. A reasonable view is that the ESC should rely more heavily on forward-looking estimates and information provided by experienced financial market observers and practitioners who have no self-interest to promote.

An alternative option is for the ESC to cross-check current estimates of the WACC with estimates based on an international version of the CAPM where markets are integrated. For an open economy, such as Australia, regulators need not choose one or the other of the segmented or integrated versions of CAPM. Rather, they should examine both, on an internally consistent basis, and then determine a preferred estimate between the two extremes represented by each model.

If regulators fail to accept this view and a domestic version only is used, the bias imported to the resulting WACC estimate (as a result of model choice) should be clearly acknowledged.

The current outcome is that all Australian regulators, particularly the ESC and ACCC, are making decisions and judgements for energy utilities that are excessively conservative and to the detriment of consumers.

The evidence from recent decisions included above show that UK regulators, and UK financial markets, accept that 'market expectations' are different to historical 'evidence'. They also accept that all regulated utility sectors present similar risks that are significantly lower than the market as a whole (although, in common with Australian regulators, the UK regulators insist on adopting values they openly acknowledge are 'conservative' – so as not to act as a disincentive for investment).

Australian regulators, by comparison, continue to ignore the UK precedents and also continue to come down with markedly different judgements on the value of WACC for different utility sectors and even the same sectors in different jurisdictions.

Recent decisions in Australia also show strong segregation between the ORG/ESC and other jurisdictional regulators. The ORG/ESC's decisions for electricity and gas provide significantly greater returns than almost all other jurisdictions; and all regulators continue to set higher WACC values for energy utilities than water utilities even though risk profiles would appear to be similar. The difference between ORG/ESC judgements and (most) other Australian regulators is costing consumers in the order of $55 million per year.

Given the high cost for consumers of its previous decisions on WACC, the ESC needs to explain why it should continue to:

- adopt a different approach to setting a value for MRP than UK regulators;
- adopt higher WACC values for energy utilities than virtually all other Australian jurisdictional regulators; and
- adopt higher values for energy utilities than for water utilities.

It seems reasonable to suggest that the ESC set WACC for the Victorian DBs in the range as low as 5.0% and certainly no higher than 6.0% thus allowing consumers to gain the benefits of efficient financing of energy utilities.

5. Interval Meter Roll-out

The ESC has commissioned consultants ECG to review the DBs' meter rollout proposals, and this review is still underway. The ESC advised in the *Position Paper* that ECG's findings will not be available until the Draft Determination is published in early June. Therefore it is not possible to make any detailed comments on the ECG findings.

5.1. Interval Meter Costs

However, as shown in the Table below, the total capital requirement forecast by the DBs for the interval meter rollout mandated by the ESC is considerable. The total figures are for costs incurred in the 5 year regulatory period, although the rollout program is intended to extend a further 2 years to 2012. Most of the cost is attributed to the meter installation process.

TABLE 2: FORECAST METERING CAPEX ($JUN04)

	2006	2007	2008	2009	2010	Total
AGLE	$13.2	$7.8	$9.4	$19.6	$20.5	$70.5
CPL	$11.3	$15.0	$15.0	$14.7	$16.6	$72.6
PCL	$17.8	$29.4	$44.8	$42.8	$45.7	$180.6
SPI/TXU	$94.6	$95.8	$47.9	$31.1	$16.2	$285.6
UEL	$25.5	$14.5	$45.3	$24.7	$26.6	$136.6
Total Metering CAPEX	$162.4	$162.4	$162.5	$133.0	$125.6	$745.9

Note: Includes meter, installation and IT system costs. Some assumptions were required in interpreting DBs' proposals. Not all DBs disclose full details of CAPEX, O&M, IT costs, revenue attributed to metering and Excluded Service Charges. The total number of meters to be installed over the five-year regulatory period is around 1.15 million giving an average total cost of $647.40.[69]

The revised meter rollout costs presented in the ESC *Position Paper* result in forecast (incremental) metering services revenue growing for a total of $61.3M in 2006 up to $175.6M in 2010 (and $207M by 2012).[70] This translates into an incremental additional price impost between $5.22/year and $54.26/year for single phase meters.[71]

It is difficult to understand why the DBs' proposed interval metering costs are so high. The total cost of the meter and installation is about 4 to 6 times the average total cost of

[69] It is noted that the ESC *Position Paper* provides updated information on meter numbers (pp201-202) and meter installation costs (p207), but only in Bar Chart form. Meter numbers are not shown by consumer segment, but by meter program classification and meter type. It is not possible to make any accurate comment on average costs by consumer segment.

The total number of meters indicated from the Charts remains around 1.63 million, of which around 1.2 million are single phase. These meters are to be rolled out in a 7-year program from 2006-2012. There is no indication of how many old-style accumulation meters will remain in service after 2012.

Average "unit costs", excluding O&M and IT costs, appear to be around $350 (range $250-$550) for "single phase non-off peak meters" and $450 (range $180-$850) for "single phase off-peak meters". An additional total amount of around $100M is proposed for IT system costs (p214), and a further $28M for "indirect *costs allocated to the metering price control*" (p216), with O&M costs totalling around $6.4M/year (p209). These additional costs give an indicative average of around $100/meter spread of the 7-year roll-out.

The overall indicated average cost appears to be around $500/meter all up for single-phase meters.

[70] Table 12.4, p220.

[71] Table 12.5, p220.

the ENEL roll-out in Italy, which not only includes an interval meter but also sophisticated two-way powerline carrier communications technology with capability to offer interactive load control, and the IT systems required to handle all the data.[72]

The DBs meter roll-out costs also appear to be up to 3 times higher than the Ontario Electricity Distributors' Association estimates for a Victorian-scale interval meter roll-out of 800,000 meters over 3 years (and the Ontario costs include Stranded Asset recovery and interval meters capital costs that appear much higher than equivalent meters in Australia).[73]

The ENEL roll-out does offer opportunities to exploit economies of scale that could not be achieved by any of the Victorian DBs, but it is inconceivable that a unit cost up to 600% higher could be efficient even for a smaller scale roll-out.

Nor is it clear what is to happen to those consumers who retain standard accumulation meters. About 1.63 million meters are to be rolled out over six years (to 2012), which suggests half a million consumers will not have meters (unless these customers already have interval meters that have been installed at the last for a five years - see next point).

This is one of the matters that will, hopefully, be clarified in ECG's review for the ESC. However, the DBs say nothing about Australian meter manufacturers not making electronic accumulation meters for several years. It is understood that any new electronic meter installed since (around) 2001 is very likely to have been interval-meter capable even if it is only being read as an accumulation meter. Information from Australian meter manufacturers suggests at least 200-300,000 interval meters suitable for Residential consumers, both single and double element, have already been rolled-out in Victoria – within the current regulated revenue benchmarks. This begs the question as to why costs for the remaining roll-out should be so high.

It is also of concern that:

- The time to complete the roll-out is relatively long, as it will not start until 2006 and is to extend to 2012. By comparison:

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[72] See: *ENEL Telegestore Project is on Track*, Vincenzo Cannatelli – Enel Group, Italy. Metering International, Issue 1, 2004.

This article confirms information provided to Pareto Associates by ENEL some years ago, that the meter and associated powerline carrier communications hardware costs of the ENEL roll-out were in the order of US$65 per installation. ENEL also confirmed the average installation cost could be around US$20 per meter.

[73] See: http://www.eda-on.ca/eda/edaweb.nsf/0/C132012C8366C33085256F4A0072C976

The Ontario Electricity Distributors' Association claims that the average all-up cost of the interval meter roll-out (including the Stranded Asset cost of existing meters) is in the range CA$315-325, with the capital cost of an "interval meter" estimated to be CA$250.00. The meter costs is substantially more than AU$65 for an Email-Ampy single element P1 or AU$130 for a two-element A11L with 70A hot-water switch, which are indicated costs in Australia. Substituting the CA$250 meter cost for (say) CA$100 for a dual element interval meter in large volumes in Australia would reduce the total roll-out average cost to about CA$160-185/meter - including recovery of Stranded Assets.

If the Stranded Asset cost is removed (to allow for recovery by the Victorian DBs of Stranded Assets through DUoS), and a "sensible" capital cost for the new interval meters included, the Ontario unit cost reduces by about another CA$30 to CA$130-155 (or AU$135-160/meter).

This is in the order of AU$500/meter lower than the costs indicated in the DBs' proposals - and not all that much higher than the unit costs of the very much larger volume ENEL roll-out.

- ENEL expects to complete its roll-out within 3-4 years (and achieve a payback of the US$2 billion investment cost in less than 5 years from improvements in its distribution and retail business);
- The initial phase of the Ontario roll-out (800,000 meters) is to be completed by 2007, with the remaining 3.5 million completed by 2010.

- Only Citipower and Powercor are proposing to install (mid 20th Century) ripple control technology for a total cost of about $45 million. But there is no indication of how this will be used or how many consumers would benefit from any additional service.
- None of the DBs propose to trial sophisticated two-way communications and load control capability similar to that being rolled out in Italy and Ontario. (Apart from allowing for the possibility of installing communications capable meters, and possibly installing meters with switches suitable for remote control of AC load.)

It is particularly disturbing that the ESC's initial position is that: "*No submissions indicated that customers were (1) willing to have loads controlled by the distributor, and (2) prepared to pay the additional cost for the "ripple control" technology.*

Accordingly, the Commission's preliminary view is that the expenditure for "ripple control" technology should not be provided in the revenue requirement. However, where the benefits exceed the costs, the distributor may choose to install this technology. Additionally, such innovations may evolve through a more competitive metering market."[74]

The ESC has, in fact, received a number of submissions from consumer groups since 2000 suggesting that remote load control should be examined closely.[75] This is particularly because application of time-of-use tariffs, similar to United Energy's, will adversely impact large numbers of AC-using consumers.[76]

Without automatic load control capability, adversely affected consumers have few choices – apart from denying themselves use of the ACs – if they wish to avoid substantially higher bills. If this generates adverse consumer reaction, which is very likely, the ESC may be moved to impose transitional arrangements or tariff design constraints on the DBs (and even retailers) which will drag out achievement of the benefits of interval metering over even longer time frames than already

74 p225, ESC Position Paper.

75 At least three of these are:

Smart Meters for Smart competition - Handing Back Power to Consumers, Comment on Current Policy Affecting Interval Metering and Load Profiling for Full Retail Competition in Electricity, Pareto Associates Pty Ltd. Report for the Customer Energy Coalition, May 2001.

Smart Meters for Smart Competition? Will Current Proposals Hand Back Power to Consumers? Update 2003 A consumer-focussed comment on the Victorian Essential Services Commission Position Paper Installing Interval Meters for Electricity Customers - Costs and Benefits, Report For The Energy Action Group, Pareto Associates Pty Ltd, March 2003; and

Customer Impacts of 2001 Electricity Distribution Price Review, Report to the Consumer Utility Advocacy Centre from Customer Energy Coalition, Pareto Associates Pty Ltd, September 2003.

76 The three reports above demonstrate that United Energy's network tariffs have a dramatic impact on AC-using consumers, raising total costs by hundreds of dollars per year for moderate AC loads of 2-4kW. The only reasons this has not become an issue already is that ORG's 2000 Determination prevents compulsory re-assignment of consumers to United tariffs just because of a meter change and no retailer offers a matching product that reflects the costs of United time-of-use tariffs.

anticipated. This would be a very poor outcome for consumers forced (by the ESC) to bear higher costs.

- None of the other DBs propose to follow United Energy's example and introduce a range of cost reflective, time-of-use tariffs that would apply to all customers with interval meters. Only one or two DBs (vaguely) mention revising their tariff structures during next regulatory period. Other DBs will leave tariff redesign until all meters are rolled-out, that is after 2012.
- The ESC has no powers to determine whether or not retailers develop time-of-use tariffs, which would deliver the cost and/or benefits of cost reflective, time of use network tariffs to the affected consumers.
- In addition, several DBs refer to the rules contained in the ORG's 2000 Determination that (supposedly) prevent compulsory assignment of existing customers to new network tariffs unless that is a significant change in load type or characteristic.[77]

Again, it is particularly disturbing to note that the ESC proposes to "*allow distributors to mandate the re-assignment of customers where distributors have installed an interval meter. Such re-assignment would occur where an interval meter has been installed and/or a change in a distribution customer's load and/or connection characteristics has occurred*."[78]

It may be some comfort to consumers that the ESC "*remains of the view that some form of consultation with customers is required prior to any re-assignment occurring*." However:

- the proposed method of addressing this is likely to impose substantial demands on consumer groups which the ESC must address because the ESC "*is proposing to establish, at the conclusion of this price review, a working group comprising representatives of the Commission, distributors, retailers, end-user representatives and relevant Victorian departments to develop transitional arrangements for the rollout of interval meters*;" and
- the ESC rejected a sensible suggestion from CUAC that tariff designs be guided by more than addition of one general criterion "*that tariffs should signal the impact of additional (peak) usage on future investment costs*"[79] to the lower and upper bound economic efficiency criteria of 'marginal cost' and 'bypass cost' specified in ORG's 2000 Decision.

The time-of use interval meter tariffs introduced by United Energy in 2001 are intended, and appear to, effectively "*signal the impact of additional (peak) usage of future investment costs.*" Given that wider introduction of similar tariffs (reflected in retail tariffs) will have dramatic impacts on small consumers, the ESC must do more than

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77 It is not at all clear that these 'rules' offer protection to consumers. The 2003 Pareto Associates Pty Ltd report to the Customer Energy Coalition refers to specific examples listed in the DB Tariff Reports that suggest these "rules" are interpreted so as to benefit the DBs. (See: *Customer Impacts of 2001 Electricity Distribution Price Review*, Report to the Consumer Utility Advocacy Centre from Customer Energy Coalition, Pareto Associates Pty Ltd, September 2003).

78 p188, ESC *Position Paper*.

79 p191, ESC *Position Paper.*

consult on the issue and reject any consideration of rolling out automatic load control technologies with interval meters.

5.2. Impact on consumers

Neither of the ESC's *Papers* clearly identifies the cost impact on individual consumers of the interval meter roll-out, and what information is provided is confusingly presented.

Interval meter revenue is shown for small consumers,[80] but not for large consumers; and the annual metering charges for small consumers proposed by different DBs (for exactly the same service) are all over the place.[81] Nor is it entirely clear what these prices relate to. The ESC says "*it is proposed that customers with an annual consumption of less than 160 MWh that utilise the metering services provided by the distributor will pay charges under the metering price control*" but shows the charges as "*Meter Provision*" and "*Metering Data Services*" that appear to be unconnected.

The revenue for small consumer interval metering is shown rising from $61.3M in 2006 to $175.6M in 2010 (and $207M in 2012). Preliminary estimates of total tariff revenue without interval metering are shown in Figure 3 of this submission.[82] Comparison of these tow data sets suggests interval meter revenue rises from about 4.2% of non-interval meter revenue in 2006 to about 10% of non-interval meter revenue in 2010. Of course, all customers are also still paying for the stranded accumulation meters in their tariff revenue - but nowhere does the ESC say how much of the non0interval meter revenue this comprises..

The "Meter Provision" charges quoted by the ESC range from $4.54/y for TXU (1 phase non off-peak) to $54.26/y for AGL (1 phase off-peak). But it is note entirely clear how the ESC (or DBs) derived these figures. They could be the average cost paid by all consumers to cover the costs incurred in metering just some.

Even so, an average small consumer with hot water would probably have a bill of around $800-1000/year, which suggests AGL's price would add up to 5 -8% to their bill. A small consumer without hot water (around average consumption) would pay around $500-700, and the interval meter charge would appear to add between 1% and 2.5% to their bill. However, few of these consumers not to have an interval meter installed under the ESC's roll-out priorities.

It is also noted that, among other things, the ESC's proposed interval meter working group would be involved in developing "*a hypothetical bill demonstrating what impact the introduction of interval meter tariffs will have upon the average household or business bill*". The ESC needs to do much better than this.

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80 See Table 12.4, p220 ESC *Position Paper*.

81 See Table 12.5, p220 ESC *Position Paper*.

82 Figure 3 shows preliminary estimates of revenue with and without interval metering. As stated in the text the interval meter revenue estimates were based on some assumptions because the initial DB submissions did not provide sufficient data to determine the revenue for all DBs. It is noted that the figures shown in Figure 3 are not the same as the ESC's figures in Table 12.4 of the *Position Paper* (although they are not wildly different)

At the level of average cost indicated of around $500-$650 per metering installation over the five year period, it is likely that Residential consumers would receive significantly less benefit from the interval meter rollout than might otherwise be the case. Residential consumers are unlikely to benefit overall at this level of average cost.

This conclusion is supported by detailed analysis of a small set (ten in all) of individual Residential consumer interval meter undertaken by Pareto Associates Pty Ltd (Pareto)[83] in 2003. <u>It should be noted that each of the reports containing information on this analysis has been submitted to the ESC, and formal presentations made to the ESC's Customer Consultative Committee on some.</u>

Pareto used actual interval meter data provided by one of Victoria's major energy retailers[84] and applied United Energy's interval meter time-of-use tariffs to the recorded load profile. In very brief summary, this showed that:

- Residential consumers on (near) average consumption with air-conditioning would face higher total annual bills (up 3.3% to 24% for a 2kW AC load; and 32% to 40% for a 4kW AC load);
- this cost impact may only be mitigated if the AC users they were also big users of Off-Peak energy (and their AC load was moderate (less than 4kW); and
- Residential consumers without AC could achieve annual savings of between 10% and 28%.

In each of the data sets analysed, consumers without AC were better off – with reductions in total bills ranging from around $130/year for a moderate (about average) household to over $500/year for a large energy consuming household (about 3 times average) with Off-Peak hot water. However, this analysis assumed no increase in metering costs and took no account of the fact that AC penetration had (by 2003) reached around 50% of households in all income groups.[85]

A particularly interesting feature of the analysis was the very different financial impact on households with similar AC demand and similar total annual consumption. This reflected whether or not the AC was used during the periods nominated by United for imposition of the Summer Demand Incentive Charge (SDIC).[86]

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83 *Smart Meters for Smart Competition? Will Current Proposals Hand Back Power to Consumers? Update 2003 A consumer-focussed comment on the Victorian Essential Services Commission Position Paper Installing Interval Meters for Electricity Customers - Costs and Benefits,* Report For The Energy Action Group, Pareto Associates Pty Ltd, March 2003; and

p13, *Customer Impacts of 2001 Electricity Distribution Price Review,* Report to the Consumer Utility Advocacy Centre from Customer Energy Coalition, Pareto Associates Pty Ltd, September 2003.

84 The interval meter data sets were selected by the retailer to represent "typical" consumers, with both "normal" and "large" annual consumption. There were four basically different consumer cohorts represented (1) No AC; (2), No AC and no Off-Peak hot water; (3) AC; and (4) AC and Off-Peak hot water.

85 ABS surveys on AC use were undertaken in June 1994, March 1999 and March 2002. These surveys show AC penetration increasing in all jurisdictions. 52.9% of Victorian dwellings had ACs in the 2002 survey, up from 26.9% in 1994 (see Table 4.16, ABS 4602.0 *Environmental Issues - People's Views and Practices*.). At least 66% of all ACs in Victoria were (higher energy using) reverse-cycle or refrigerative models (See Table 4.17).

86 The United Energy tariffs are relatively complex. The SDIC is incurred on the highest half-hour in each billing period between 3:00PM to 6:00PM on Working Week Days from 1 November through 31 March for the RCAC and kWh-TOU tariffs; and 3:00PM to 6:00Pm on Working Week Days over 35°C for the kWh-TOU-HOT tariff.

Residential consumers without hot water or air-conditioning (AC) on average consumption may still achieve overall benefit that exceeds the proposed interval meter cost levels, but this is by no means certain. For example, as mentioned above other distributors have so far indicated to the ESC that they are not planning to follow United's lead and develop identical tariff structures and designs during the next regulatory period – and not one retailer has developed a tariff that passes on the benefits and costs of United Energy's ToU tariffs to affected consumers – even though United has been 'offering' these tariffs since 2001.

The DBs' proposals seem out of touch with ESC's Final Decision on interval metering. A few quotes from the ESC's decision illustrate this:

> *"Modern interval meters are the building blocks that will facilitate developments in a wide range of complementary products and services."*
>
> *"The Commission has also varied the draft decision in respect of the communication capability of the interval meters. All meters are to be communication enabled (utilising 'open systems architecture') to ensure that the meter can facilitate remote reading without the need for a further meter changeover."*

However, the DBs' proposals suggest that:

- The 'market' will have to provide the communications capability/load control functionality that would enable more convenient (for consumers) delivery of potential interval meter benefits. But
  - without convenient, automatic, remote load control (which, as the Ontario government and ENEL have recognised, would be able to be most efficiently installed by DBs), capture of whatever benefits are offered by retailers could only flow to non-AC users and any AC users who manually choose not to be cool when it is hot; and
  - neither the ESC's Interval Meter Decision, nor the DBs' proposals specifically target AC users (who are those driving substantial costs in all sectors of the electricity supply chain);

It should be noted that the SDIC charge accounted for up to 1/3rd of the total bill in the interval meter data sets that were analysed by Pareto. Sensitivity analysis undertaken by Pareto also showed that load management during the SDIC charging time periods could have a substantial impact on the total bill amount. As Pareto noted:

> *Of course, tariffs such as those implemented by United are not all bad news for consumers. Consumers who are able to shift significant consumption (and half-hourly demand) past 7:00PM may achieve substantial savings in their bills. But to be successful they would have to ensure they did this every Working Week Day in each billing period from 1 November through 31 March. If they missed load shifting just one Working Week Day they would incur the SDIC charge for the whole billing period. This is because the United SDIC charge applies to the highest half-hourly demand between 3:00PM and 6:00PM in any Working Week Day in the billing period.*
>
> *A consumer who succeeded in shifting/curtailing load nearly every Working Week Day would not avoid the charge. That is economically rational, but it is unarguably a very high hurdle. No reasonable household could ever expect to achieve that goal using manual load control.*

(pp 31-32, *Smart Meters for Smart Competition? Will Current Proposals Hand Back Power to Consumers? Update 2003 A consumer-focussed comment on the Victorian Essential Services Commission Position Paper Installing Interval Meters for Electricity Customers - Costs and Benefits*, Pareto Associates Pty Ltd, March 2003).

- The extended roll-out period will allow at least another decade to develop the full effect of AC load, which will drive billions of dollars in sub-optimal investment in generation, transmission and distribution; and
- Interval Meter charges will be Excluded Services Charges - and all other DBs will be able to join United Energy and claim in their Tariff Reports that Fixed Costs have been reduced (possibly to zero) when, in fact, consumers look certain to be subject to substantially higher fixed Excluded Service Charges for interval meters.[87]
- The ESC is proposing an "M Factor" to "bribe" DBs to roll-out interval meters (and make interpretation of regulatory outcomes even more complex).

5.3. Problems with the DBs' Response to the ESC Interval Metering Program

Another difficulty with the DBs' proposals for the interval meter rollout is that there is nothing which clearly outlines how consumers would benefit from this program. The DBs are proposing the minimum required to meet the program imposed on them by ESC (with what appears to be substantial padding of the cost forecasts).

Fundamental problems with the ESC's program, and the DBs' responses, are:

- there is no attempt to assign interval meters to consumers with AC, even though all the DBs confirm either directly or indirectly that it is those consumers that are driving substantial costs - and the need to invest in more network capacity; and
- the proposal to offer incentives for the DBs to meet the ESC's program will increase costs to consumers.

The flaws in the strategic framework for the interval meter rollout mean that it is much less likely that consumers will gain any benefit overall, particularly since the proposed Excluded Service Charges applying to interval metered consumers appear to be more than 100% higher than the metering charges currently imposed for accumulation meters.

The obvious strategic flaws in this program will almost certainly impact in a negative sense on all consumers who do not contribute to AC demand in a significant way. This includes low-income households without AC, households with small AC units (less than 2 kW demand) and business consumers (small and large) with substantially better load profiles than AC using households. The lack of regulatory specification, or regulatory oversight of cost allocation methodologies and detailed tariff designs means that it is impossible to be sure that these consumers will not bear at least part of the increased cost of providing the capacity to meet increasing AC demand.

[87] We note that the ESC acknowledges that the requirement, imposed by ORG in 2000, for DBs to prepare Annual Tariff Reports "*does not adequately assist customers to understand tariff structures, the cost allocation underlying them or the movement in tariffs over time*", which is an understatement.

The ESC's proposal is to also require the DBs to produce a 5-year, overarching, Tariff Strategy Report. It is not clear this will improve transparency of pricing information for consumers unless it integrates tariffs and Excluded Service Charges, and shows meaningful details on the actual costs allocated to each tariff and Excluded Service Charge in a way that can be directly compared with information on a consumer's bill.

Another issue that requires further clarification is what is driving the forecast cost of meter installation. For example, TXU says it will cost $129.74 to install a single phase, single element meter (plus $15.98 in Back Office (Install) – what ever that means) and $142.74 (plus $23.98), for what is presumed to be a single phase, two element meter (for Off-Peak hot water). Direct observation of a meter installation shows that it is possible to install a single phase, two element interval meter (not requiring any re-wiring or connection to a hot water circuit) in a matter of minutes.[88] A reasonably designed installation program should allow significant numbers of meters to be installed in a single visit to one 'precinct' in a DBs supply territory (even if not all meters are replaced in a single precinct).

It appears clearly that the DBs are including a substantial element of 'monopoly' cost padding, or significant inefficiencies, in their interval meter roll out costs. Either way it would be highly inappropriate for the ESC to accept these costs as the stand. The ESC needs to require the DBs to provide much greater information to show how much of the installation cost is related to:

- re-wiring of meter boards to accommodate the simpler, single meter installation compared to 2 meter plus separate time-switch of conventional Off-Peak hot water metering installation;
- rewiring to achieve compliance with current Electrical Safety Standards, where an existing metering installation is found to be non-compliant;
- replacement of asbestos-cement meter board; and
- proof that the meter installation program is planned so as to minimise the total cost.[89]

5.4. Improve the Tariff Reports

The proposals to exclude metering costs from regulated revenue and charge for metering as an Excluded Service Charge will mean, if nothing changes in the Tariff Report arrangements, the metering charge will not show up in the Tariff Report. This means that the Tariff Reports are of limited practical use to any consumer who pays an Excluded Service Charge as part of the regular bill.

Another issue identified in the 2003 report by Pareto Associates for the Customer Energy Coalition was that the treatment of metering costs as Excluded Services (in the case of United Energy) allowed United to claim that it had eliminated fixed charges from its interval meter tariffs, when in fact it allocated a separate Excluded Service Charge for the

[88] Australian standards require all meters to be constructed with connection points that align with those specified in the (DBs) Victorian Service and Installation Rules. Therefore it is possible to simply remove and old meter and replace it with a new meter without any major reconfiguration of the meter board. All installations with electronic meters, or single phase, single element Ferraris disk meters, should be capable of change-over without reconfiguring of the meter board.

However, it is acknowledged that older metering installations supplying Off-Peak loads will have to be reconfigured once the electromechanical time switch and Off-Peak Ferraris Disk meter are removed.

[89] For example, ENEL (the Italian electricity utility) has reported it has achieved an installation rate of 700,000 per month for its much more advanced metering and two-way communications system. (See: *ENEL Telegestore Project is on Track*, pp16-21 by Vincenzo Cannatelli – Enel Group, Italy, Metering International, Issue 1, 2004).

metering component which was higher than the fixed quarterly charge for a standard metered customer.

It is not at all clear that the ESC's proposal to require the DBs to also produce a 5-year, overarching Tariff Strategy Report will improve the situation for consumers unless this report (or the Annual Tariff Reports) includes full disclosure of:

- All tariff and Excluded Service Charges;
- Details of how costs are allocated to each tariff and/or Excluded Service Charge;
- Details of the actual costs allocated to each tariff and/or Excluded Service Charge;
- Information that allows a direct comparison between the Tariff Reports and a single consumer's actual bill.

The ESC must therefore require a higher level of disclosure from the DBs in the next regulatory period in relation to excluded service charges, particularly those relating to the roll out of interval meters..

6. Demand Management

The need to develop more effective demand management in the electricity market is widely recognised. This has been confirmed in the Council of Australian Government (CoAG) Energy Market Review and Ministerial Council for Energy (MCE) energy market reform agenda. It is beyond doubt that the ESC and the DBs have a key role to play in ensuring that this development occurs.

This section of the submission provides a very brief overview of some of the key issues related to features in economic regulatory regime that apply to electricity distributors that have the effect of impeding demand management. Comment is also made on the inadequate response by all of the DBS and the ESC in the face of a clear need to facilitate development of demand management.

6.1. DM – What is on offer?

There is nothing in any of the DBs' proposals about Distributed Generation or Energy Efficiency. The proposals for Demand Management, apart from Citipower and Powercor's unspecified proposal to roll-out (mid 20th Century "ripple control" technology), are all focussed on "negative incentives" and do nothing to assist consumers respond to "clearer" pricing signals. Some examples below help to show this.

AGLE:

> *(p33) Demand forecasts are used in the assessment of network adequacy to identify system deficiencies. This leads to investigations into network solutions and non-network solutions (such as demand management). The demand forecasts are one of the main drivers for AGLE's five-year network strategic capital expenditure plan.*

This is the comment on demand management in AGL's proposal and is clearly a 'Do Nothing' approach.

SPI Networks (TXU):

> (p72: s7.3.2.5) *During the 2006-2010 regulatory period, demand side management initiatives will continue to be encouraged where there is an efficient opportunity to avoid expensive reinforcement expenditure. SPI Networks do not expect the potentially more sophisticated pricing and demand management approaches that would be supported by the interval meter rollout to impact on network reinforcement capital in the 2006-2010 regulatory period.*
>
> (And p146) *SPI Networks agrees that the current approach to price controls does not prevent distribution businesses from facilitating demand side responses. SPI Networks has utilised the current price controls to establish a range of tariffs that address demand management. Examples of these initiatives are: (SPIN here lists 5 network tariffs that supposedly "incentivise" DM).*

> *NEE23 – applies to small domestic photovoltaic installations. This tariff offsets energy produced by the photoelectric cell at the same rate as the network charge and gives an explicit payment for generation into the grid over the summer period when local demands drive transmission charges.*

SPI Networks is also proposing a generally 'Do Nothing' approach – and anticipating that it will see no benefits from DM response.

But the ESC should take note that, when the NEE23 Tariff was first introduced, TXU claimed that it delivered a benefit to Solar PV users. This is clearly incorrect. The NEE23 tariff is clearly intended to impose substantially higher costs on a small grid-connected generator than previous tariffs (the Residential Single Rate tariff (NEE11)) by:

- substantially increasing the Standing Charge (by 195%);
- increasing Peak energy charges (by 12.8%); and
- discounting the payment for excess generation during summer peak periods (by 6.9%).

These sorts of tariff initiatives can only have the effect of reducing incentives for consumers to pursue and offer demand management. This is not a new issue. The ESC was advised of this situation by CUAC in September 2003.[90] It is very disappointing that the ESC failed to respond to the consumer-sponsored submission made that identified this unsatisfactory approach by TXU.

Powercor/CitiPower:

> (p18 (repeated p126)) … *new distribution tariffs will be assigned to customers when an interval meter is installed. Over the period 2006-10 these new distribution tariffs will be adjusted to provide stronger demand management signals to customers.*
>
> *Demand management signals are to be provided by the development of an excess reactive demand charge to be applied to large customers exhibiting poor power factor;*
>
> (And p96): *As the accelerated interval meter rollout only begins to ramp up from 2008, there will be minimal reinforcement savings arising during this regulatory period. Substantial opportunities may be available in subsequent regulatory periods depending on customer interest and retailer behaviour. However, this regulatory period represents a one off opportunity to install a system capable of significantly reducing future network capital investment at a substantially reduced cost.*
>
> *Installation of ripple control to those customers receiving interval meters over this regulatory period will require $25M. ($17M for CitiPower)*
>
> (And p128): *The tariff structure is also important for sending signals about the value of demand management to customers. Higher prices can*

[90] See p25, *Customer Impacts of 2001 Electricity Distribution Price Review - Report to the Consumer Utility Advocacy Centre from Customer Energy Coalition*, Pareto Associates Pty Ltd, September 2003.

> *encourage customers to reduce their demand which can in turn deliver positive environmental outcomes.*
>
> (And p129): *D1 - Small Single Rate. D1 is the basic single rate residential tariff that includes a standing and energy charge. The energy charge includes a 4 part inclining block structure that acts as a positive rudimentary demand management signal to high energy users. (Similar statement for Small Business Tariff)*
>
> (And p134): *However, during the next regulatory period it is intended that the interval meter tariffs be amended to include sharper demand management signals to customers.*
>
> (And p136): *As new load management technologies such as ripple control (see Section 6.6.8) are deployed in the Powercor Australia distribution system, new tariffs that allow these technologies to achieve their intended demand management benefits will be introduced as appropriate.*

Both CitiPower and Powercor are proposing to contemplate 'sharper' price signals for consumers (that is, impose higher costs on high cost consumers), but at least they are also proposing to do something that is intended to ameliorate the impact of 'sharper' prices by a limited roll-out of antiquated mid-20th Century ripple control technology.[91]

6.2. EUAA Demand Side Response Facility Trial

The Demand Side Response (DSR) Facility Trial[92] undertaken by the EUAA during November and December 2002[93] clearly demonstrated that coordinated demand management has potential to deliver significant commercial and economic benefits for both energy users and electricity distributors (and retailers). Scenarios tested in the Trial were designed to be as realistic as possible and specifically included targeting of typical distribution network constraints[94] that could be relieved by coordinated, locationally-specific demand response.

However, the Trial also demonstrated that a number of constraints existed that inhibit take-up of demand management by end users, distributors and retailers. Major impediments to demand management identified in the Trial were:

- the need for a coordination function that was capable of ensuring delivering of reliable and predictable demand side response capacity;

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91 As noted below and elsewhere in this submission, the submission does not necessarily support CitiPower/Powercor's proposal to roll-out ripple control technology. However, the submission very strongly supports the investigation of this and other more sophisticated load control technologies that could be rolled-out by distributors. Without sophisticated, low-cost and easy to use load control functionality, consumers have no real prospect of avoiding much higher electricity bills – and Victoria has little prospect of activating effective demand management amongst small consumers.

92 The Trial was based on testing a prototype DSR Facility that provided a coordination, despatch and settlement clearing function. The DSR Facility operator received offers for physical demand response capacity linked to 'buy and sell' bid conditions.

93 See: *Trial of a Demand Side Response Facility for the National Electricity Market: Independent Consultant's Report*, EUAA and Pareto Associates Pty Ltd, April 2004.

94 AGL Networks and United Energy participated in the Trial as Victorian distributors.

- the need to increase the understanding amongst end users of the opportunities for demand side response and the potential commercial benefits it could deliver; and
- the need to align the economic and commercial incentives (and signals) in the energy market, network and end user sectors.

The Trial was based on testing the effectiveness of a prototype DSR Facility that was capable of providing the coordination function, thereby addressing the first impediment. A key objective of the Trial was to encourage participation by its members, provide a valuable learning process for EUAA members and end-users generally, thereby addressing the second impediment.

Other impediments were identified by the active and positive participation of large end users, energy retailers and distributors in NSW, Victoria and South Australia and these have been discussed with Governments and regulators across the NEM. Key issues that related to the distribution sector were the basis for estimating the value of DSR in the network services sectors and the explanations provided by distributors for the value of and reasons for there bids.

Subsequent to the Trail, action has been initiated by Energy Response Pty Ltd to pursue commercialisation of the prototype DSR Facility tested in the Trial; and the EUAA has introduced a structured program to assist its members and other energy users identify and implement demand response opportunities.

Areas requiring close consideration by the economic regulators, including the ESC, were identified in two of the key recommendations of the Trial report. A brief comment on the relevance of these recommendations to the current review is outline below.

6.2.1. Consumers want the positive incentives for action that DBs enjoy.

The first Trial report recommendation that is directly relevant to the ESC's review is to:

> *Ensure all stakeholders understand that end-users respond best to 'positive' incentives. The Trial confirmed that commercial incentives are as important to end-users as they are to retailers and distributors. End-users made it clear that they will not provide DSR if it is not profitable to do so. The importance of this observation does not seem to be fully understood by all stakeholders.*[95]

The Trial involved large industrial and commercial energy users, but the responses and views of these users are not likely to be significantly different to small consumers.

The fact that neither DBs nor the ESC understand the importance of this observation is amply demonstrated in the DBs' proposals and the ESC's *Papers*. For example, the only references to demand management in the DBs' proposals to the ESC relate to imposition of costs onto consumers (who cause the costs). This is not unreasonable, but the Trial showed that it is not the only way, or even the best way, to stimulate demand response.

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[95] p(viii), *Op Cit.*

The ESC appears to consider the same course of action as the only one that is realistic. For example, the ESC proposes to extend the criteria for tariff design by adding a condition "*that tariffs should signal the impact of additional (peak) usage on future investment costs*". But, on the other hand, the ESC has rejected consideration of examining or implementing any form of automatic load-management functionality that would make it easier for consumers to respond to price signals and (potentially) benefit from implementation of a commercial DSR Facility.

6.2.2. DBs need clearer incentives to pursue demand management

The second Trial report recommendation that is directly relevant to the ESC's review is to:

> *Clarify incentives for network service providers to pursue DSR.* .[96]

The Trial demonstrated that regulatory incentives affect the way network service providers value DSR. Analysis following the Trial also confirmed that regulatory arrangements allow network service providers to manage physical supply risk through a very different mechanism to that used by retailers to manage risk in the energy market. The way in which regulatory incentives motivate network services and the discretion they are permitted in the management of physical supply risk can lead distributors to assign lower value to DSR than retailers, even though many of the economic fundamentals of electricity supply are basically the same for the energy and network sectors.

The 'network' test scenarios in the Trial confirmed the prototype facility could be used to provide 'network' DSR. However, each distributor submitted bids of substantially different value for circumstances that were defined as identical in the relevant test scenarios. This outcome led to considerable discussion amongst Trial participants about the distributors' pricing methodologies. While there were some similarities in methodologies adopted by each distributor, all distributors were clearly influenced by regulatory incentives and interpreted these differently.

For example, United Energy incorporated 'standardised' network reinforcement cost estimates prepared by United's consultants, temperature impact on network loading and the 'efficiency carry-over' mechanism in the Victorian regulatory regime. The focus of United's pricing methodology was strongly influenced by the details of the Victorian regulatory framework rather than purely commercial considerations.

A further example was provided in the Trial report. This was based on detailed information published in the Annual Electricity System Development Review Reports[97] required under the NSW *Demand Management for Electricity Distributors – Code of Practice* (the NSW DM Code). The example showed how that value of DSR capacity (expressed in $/MWh), as seen by an electricity distributor, changes from a very high level as peak demand approaches the capacity of a major distribution transformer to zero as soon as the transformer capacity is augmented.[98] The example also shows that even if

[96] p(vix), *Op Cit.*

[97] The information contained in the NSW distributors' planning reports is much the same as that contained in similar reports published by each of the Victorian distributors.

[98] See Section 4.2.2, p49 and Appendix G, *Op Cit.*

DSR capacity can be coordinated and despatched in sufficient capacity to defer augmentation, the value of each additional increment of DSR capacity drops substantially as the total DSR capacity required increases. The decreases in value obviously provide much reduced incentive for consumers to offer DSR capacity, or even to consider investing in such capacity.

This outcome reflects the fact that the distributor is able to recover the full cost of any investment in network augmentation once the investment occurs; and the increment of capacity that is (normally) added will also provide significant additional network capacity above the prevailing load levels. Once additional network capacity is added, the distributor has a commercial incentive to 'sell' more network capacity – not 'buy' demand management capacity. On the other hand, consumers have no continuing (or equivalent) incentive to invest in DSR capacity – and would be commercially unwise to make such investment unless they were able to derive some value other than the transitory value of the DSR capacity to the distributor.

6.3. Distributed Generation

Distributed (or embedded) generation may be seen as a particular form of DM and also suffers from some of the same impediments. It also offers a number of significant and similar benefits in terms of this review.

The Energy Networks Association argues (in its comment on the ESC's draft decision on a Victoria-specific Embedded Generation Guideline) that:[99]

> *"With the Weighted Average Price Cap form of regulation in place in Victoria and shortly to be established in NSW, there is a direct and asymmetric revenue risk associated with an embedded generator. There is also the risk of asset stranding, which is also asymmetric. The asymmetric nature of these risks means that they cannot be adequately dealt with under the Capital Asset Pricing Model currently used to determine the Weighted Average Cost of Capital."*

Issues associated with investment risk facing DBs were not dealt with in the ESC's final Decision on the Embedded Generation (EG) Guideline. It is hoped the ESC would dismiss the arguments presented by ENA out of hand. However, the ESC has previously ignored the logic of arguments that EG (particularly "small" EG) is no different to energy efficiency - as far as the consumer is concerned.[100]

The revenue risk and risk symmetry of energy efficiency (EE) and EG are identical. These risks are real in the sense that any decision by a consumer to reduce consumption results in lower revenue to all segments of the electricity supply industry in the short term. However, whatever downside EG/EE present to DBs is overwhelmed by the upside in overall demand and consumption growth – and countered in the longer-term by more efficient investment in supply infrastructure.

[99] p 3, *Submission to the Essential Services Commission Guideline for Embedded Generation - Response to Draft Decision*, Energy Networks Association, May 2004

[100] Provided the EG doesn't cause any more perturbations on the network than (say) changing to high-efficiency lighting, or stocking the consumers' premises with energy efficient appliances.

The ESC's EG Guideline still focuses on the supply side by leaving in place relatively complex "market-based" remedies (favouring negotiated outcomes, but failing to respond to the fact that users have neither information or experience to negotiate and are at the mercy of a monopoly network business in such situations, even if they are large users) and offering only mild "carrots" to users (in the form of generic, "standard" supply-side proposed terms and conditions for connection and use of DG).

This 'blind faith' in market solutions in the face of overwhelming evidence (provided by consumers) that market failure exists is also very disappointing.

The ESC is strongly urged to take a more pragmatic approach that seeks to make it as easy as possible for small embedded generators to be deployed and connected to the distribution networks[101] and provide guidelines with 'some teeth' that will have the effect of assisting larger users efficiently negotiate fair and reasonable connection agreements with distributors.

6.4. Approaches to providing incentives for demand management

The ESC would do well to follow the example of other, more progressive and consumer-focussed, regulators such as IPART and ESCoSA on this issue.

IPART recognised the role of DM in relieving network congestion and improving the utilisation of network assets, both of which would reduce upward pressure on costs many years ago. It has taken a pro-active stance on DM in its latest Determination and introduced a number of incentives to promote network DM.[102] These include the introduction of a 'D-factor' to the weighted average price cap formula, to recover costs and revenue foregone arising from DM programs, up to a maximum value equal to the avoided distribution costs.

IPART also set up a Network DM Consultation Working Group, comprising members from distributors, Government, industry and user/consumer groups to develop guidelines for distributors on various aspects DM.[103] The group has now completed this role and IPART has recently published its final guidelines.

A document entitled "*DM for Electricity Distributors Code of Practice*" ("the NSW DM Code") has also been prepared and published for use by the NSW distributors. The DM

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101 A recent submission to the ESC by the Alternative Technology Association (ATA) makes firm recommendations that would achieve this outcome (See: *Impediments to Grid Connection of Solar Photovoltaic: the consumer perspective*, ATA and Marsden Jacob Associates, April 2005). Essentially, the ATA argues that small embedded generators should be treated on the much the same basis as other forms of energy efficiency. Small embedded generator owners should be:

- permitted to stay on 'standard' Residential or Small Business tariffs;
- required only to ensure their installations comply with existing electrical safety standards;
- required only to advise their retailer that the system has been installed and connected to the distribution network; and
- permitted to accept a better offer than 'standard' tariffs if and when retailers develop such products.

102 *Determination of NSW Network Prices for the 2004/05 to 2008/09 Period,* IPART, June 2004.

103 The Energy Action Group and EUAA are members of the IPART DM Group.

Code provides an additional impetus to DM at the distribution level and has recently been reviewed and improved.

The ESC is urge to examine IPART's programs for implementation in Victoria.

In addition, in its final determination for ETSA Utilities distribution network in South Australia, ESCoSA has provided some incentives for DM in the form of adopting a DM Code that is similar to that adopted by IPART and allowed specific provision for ETSA Utilities to commit approximately $20 million over the five year regulatory period to trial a number of demand management initiatives which may result in less need for peak-driven network expansion.

The range of initiatives to be trialled by ETSA Utilities include:

- "power factor" improvements in business and manufacturing premises;
- trials of Voluntary Load Curtailment (VLC) programmes for large customers;
- Direct Load Control (DLC) of domestic equipment such as air-conditioners and pool pumps;
- use of standby generation, and
- the use of incentives for customers to reduce demand at times of peak demand.[104]

These actions by IPART and ESCoSA shows that the ESC needs to provide some additional 'positive' incentives for DM as part of the next regulatory period. If it does not do this, the ESC leaves itself open to the accusation that it is out-of-touch with the latest developments in regulation, out-of-step with other regulators and out of touch with actions that could assist in protecting the long-term interests of consumers. Victoria, which badly needs a more active DM response to help it meet the challenge of growing peak demand, will be left more exposed to the consequences, including unfettered growth in peak demand, higher Capex and higher electricity costs.

The ESC's proposals are, so far, also totally inadequate. The ESC said in the *Issues Paper* that it was "*interested in clarifying the barriers in the Commission's regulatory framework that may exist to demand side responses. Where barriers relate directly to the regulatory framework, the Commission intends to address these for the next regulatory period*."[105] But the proposals in the *Position Paper* appear to be no more than reliance on:

- "*adjustment of the DRR* (demand related reinforcement) *capital expenditure based on energy consumption* (providing) *distributors with greater incentive to maintain or improve their load profiles - since increased DRR capital expenditure caused by worsening profiles would impact the distributors' efficiency carryover amount*;[106]

[104] See p(v) and pp54-60, *2005 - 2010 Electricity Distribution Price Determination, Part A - Statement Of Reasons*, Essential Services Commission of South Australia, April 2005.

[105] p183, ESC *Issues Paper.*

[106] p87, ESC *Position Paper*.

- *not … constrain the distributors from adjusting their tariff structures in light of information obtained through the interval meter rollout and to pursue demand-side management objectives*.[107]

The only mentions of positive incentives for demand management and embedded generation in the ESC *Position Paper* are in the context of allowing exclusions from the S-Factor (where an embedded generator can be linked to a supply outage)[108] and energy efficiency and energy conservation rate no mention at all.

This is a very poor and totally inadequate regulatory response from the ESC to these important issues. It is disappointing that the ESC appears to be intransigent on this key issue and/or fails to understand the obstacles to DM in relation to networks.

The ESC needs to show clearly how its approach will facilitate DM during the next regulatory period and to what extent. The ESC has made the point during this review that it believes the current regime already provides sufficient incentives for DM to occur where "it is economic". But the ESC unfortunately fails to understand the drivers behind DM and the impediments it faces. These include its still nascent state in the NEM, cultural barriers in DB and among customers and a lack of information and awareness about its opportunities.[109]

Whilst it is acknowledged that the ESC cannot overcome all these hurdles in this review, it can be far more positive in support of DM than has been indicated to date. The ESC also needs to show why the application of positive incentives, including those provided by other regulators, are not suitable and the reasons for this. It should demonstrate this with facts and figures not mere assertions.

107 p183, ESC *Position Paper*.

108 p117-120, ESC *Position Paper*.

109 The EUAA DSR Trail clearly showed this to be the case.

Appendix A: DB Capex and Opex Performance

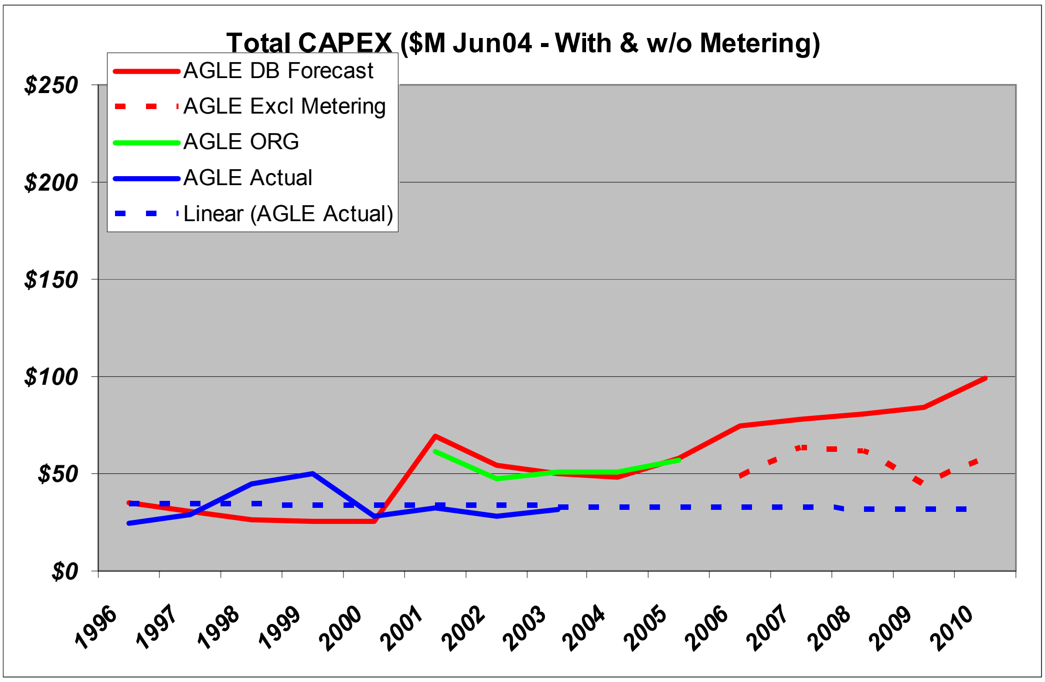

FIGURE A.1 AGLE CAPEX PERFORMANCE

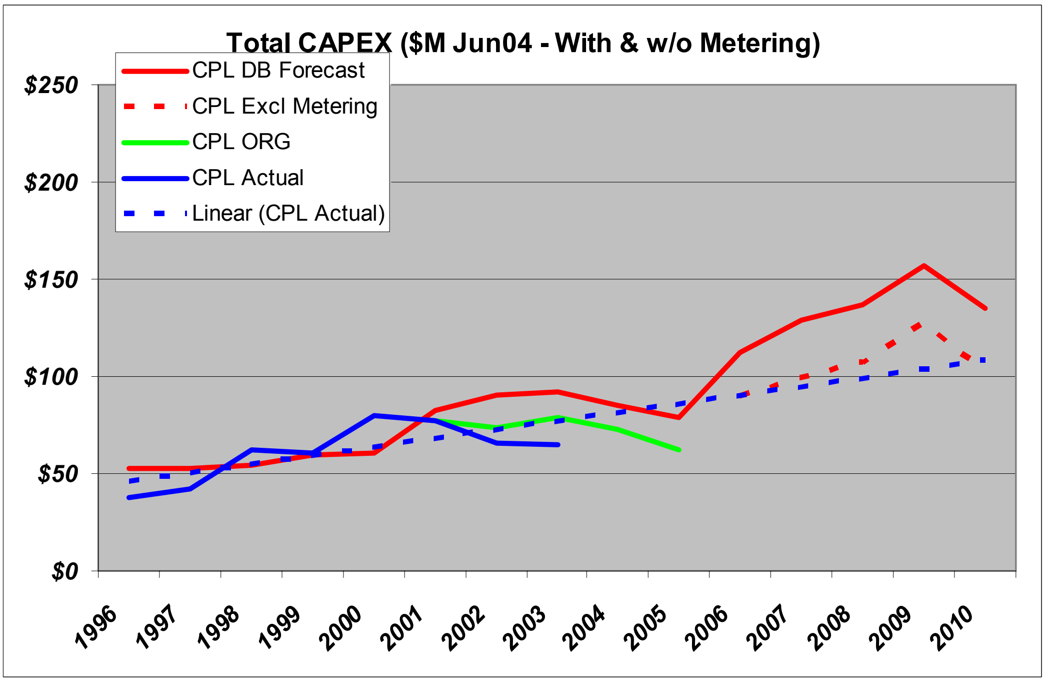

FIGURE A.2 CITIPOWER CAPEX PERFORMANCE

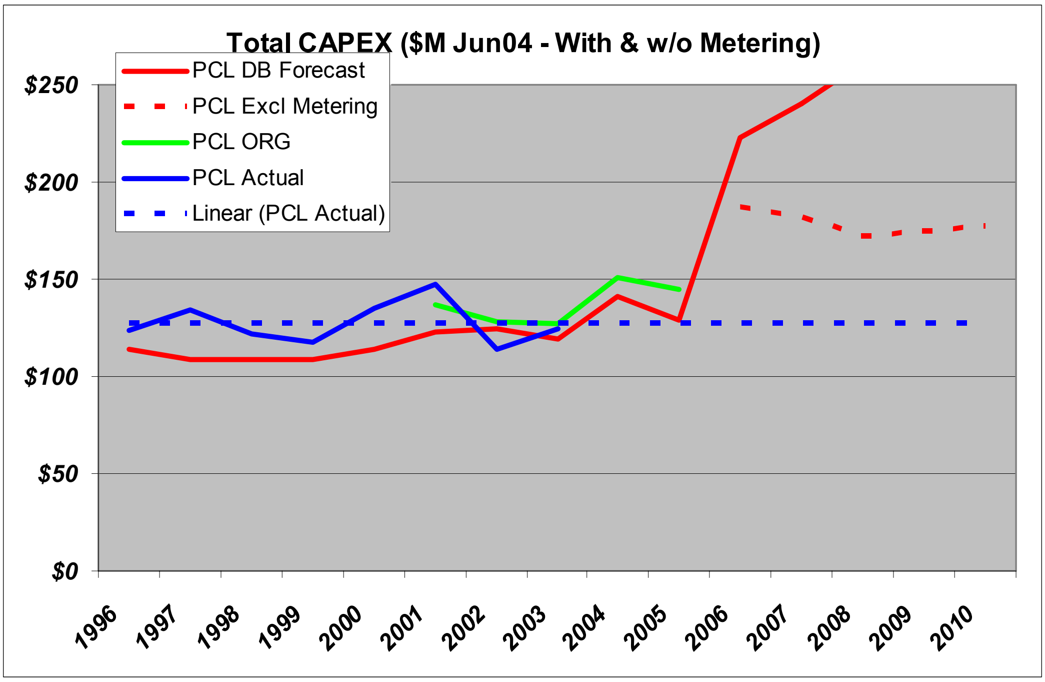

FIGURE A.3 POWERCOR CAPEX PERFORMANCE

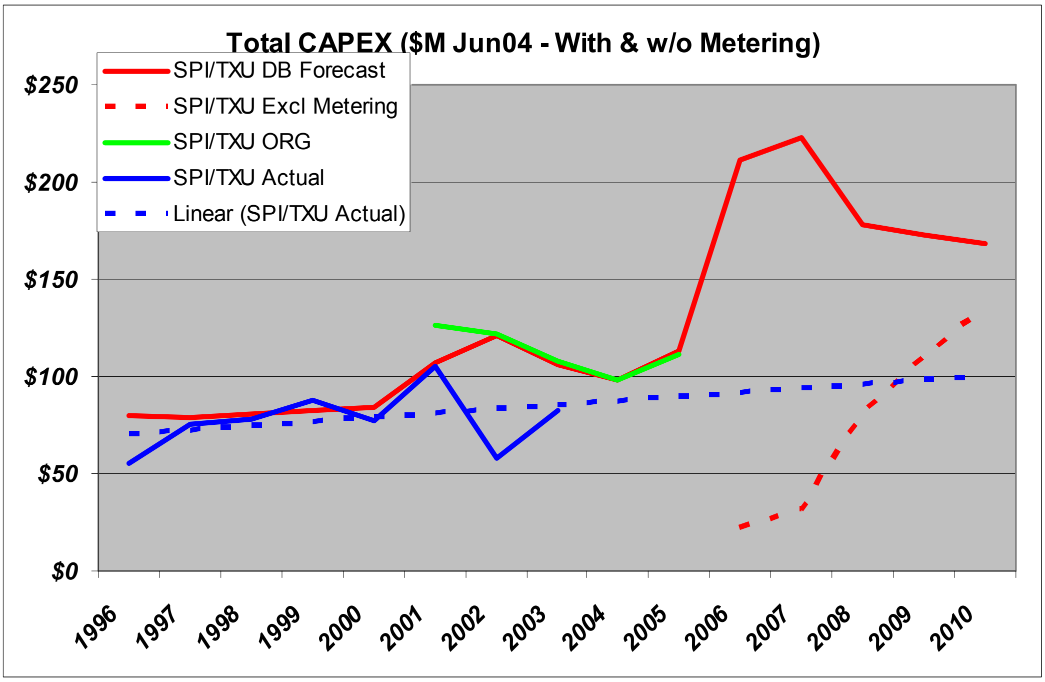

FIGURE A.4 TXU/SPI CAPEX PERFORMANCE

Note: We have not examined TXU's submission in sufficient detail to understand why the Capex forecast excluding metering appears to be much lower than actual Capex for the current regulatory period.

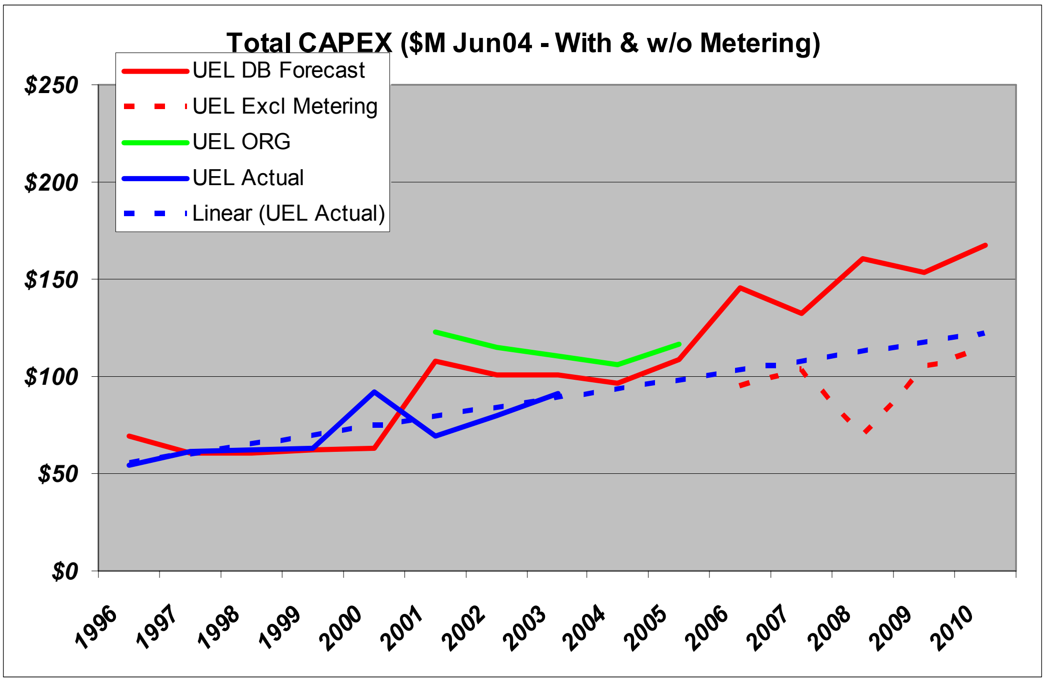

FIGURE A.5 UNITED ENERGY CAPEX PERFORMANCE

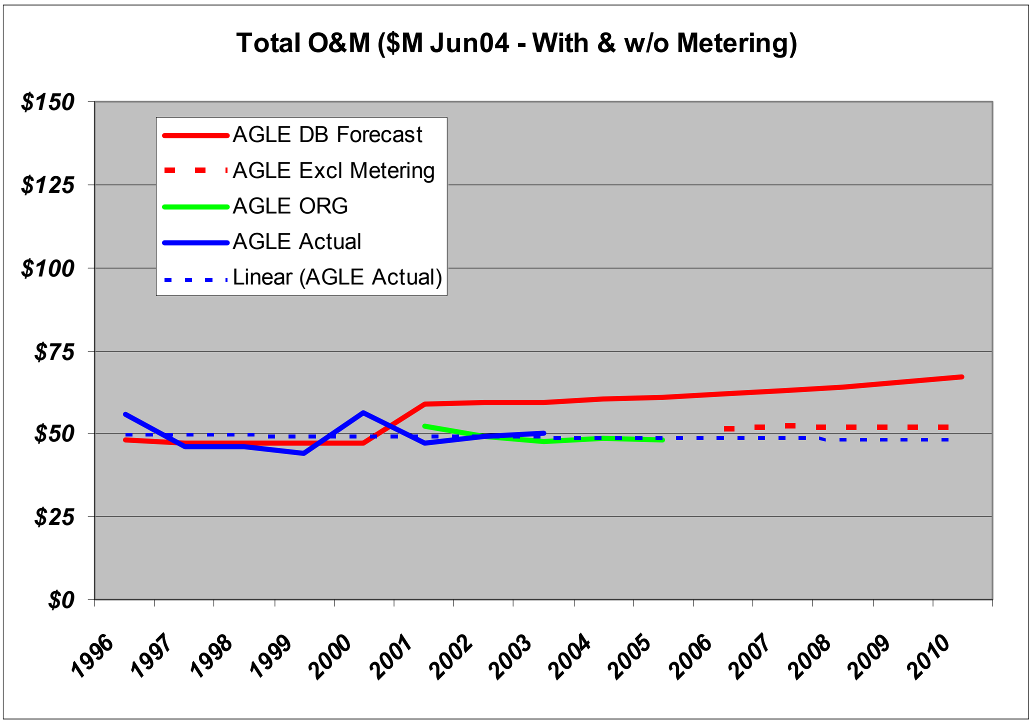

FIGURE A.6 AGLE OPEX PERFORMANCE

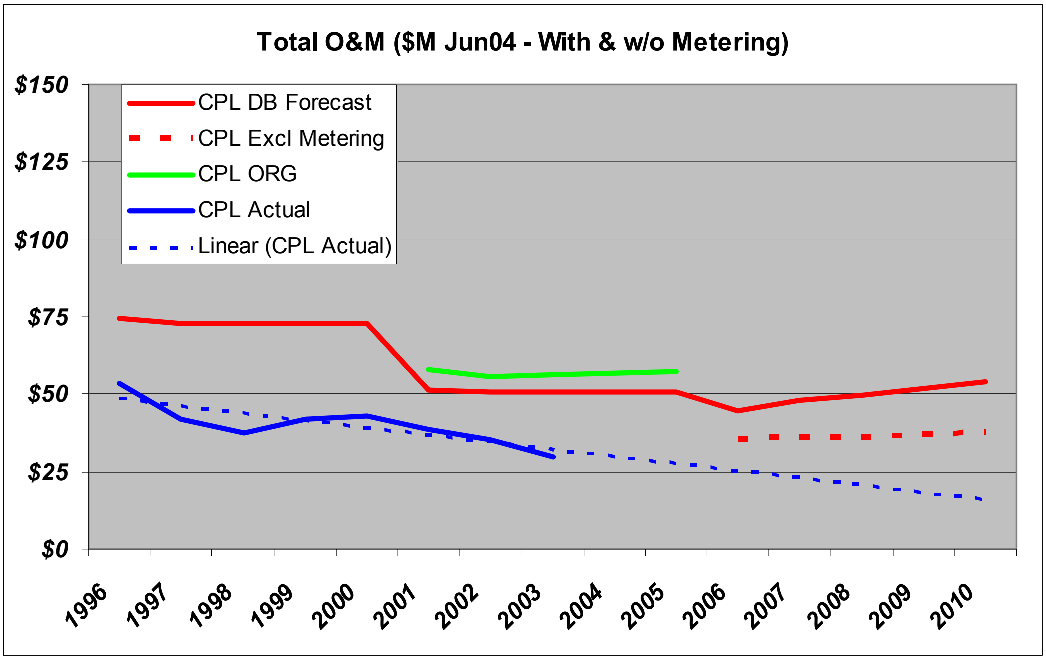

FIGURE A.7 CITIPOWER OPEX PERFORMANCE

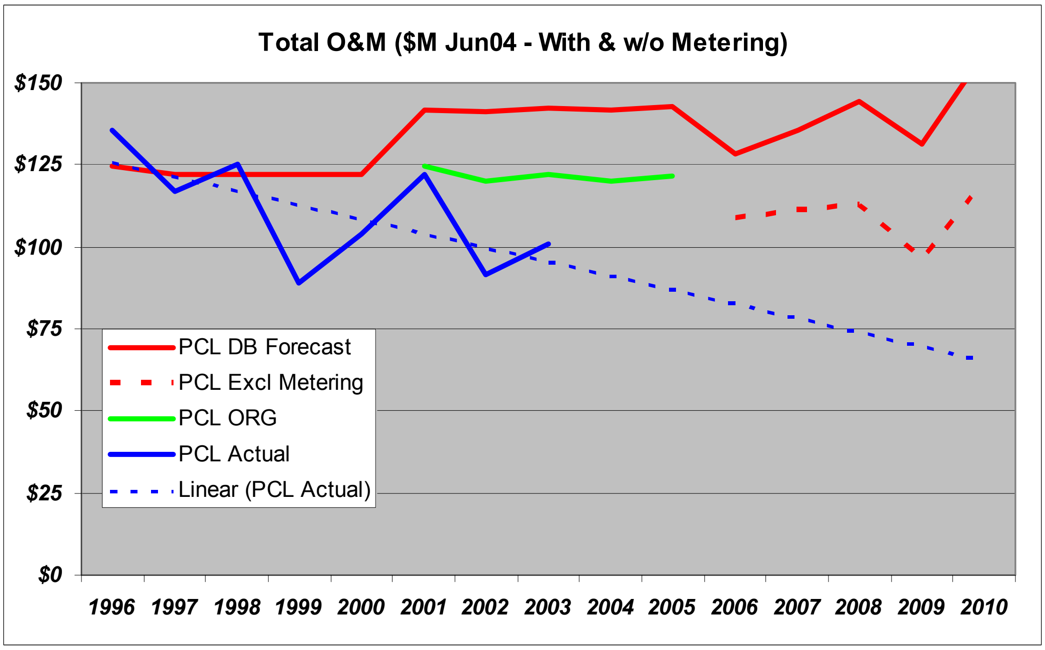

FIGURE A.8 POWERCOR OPEX PERFORMANCE

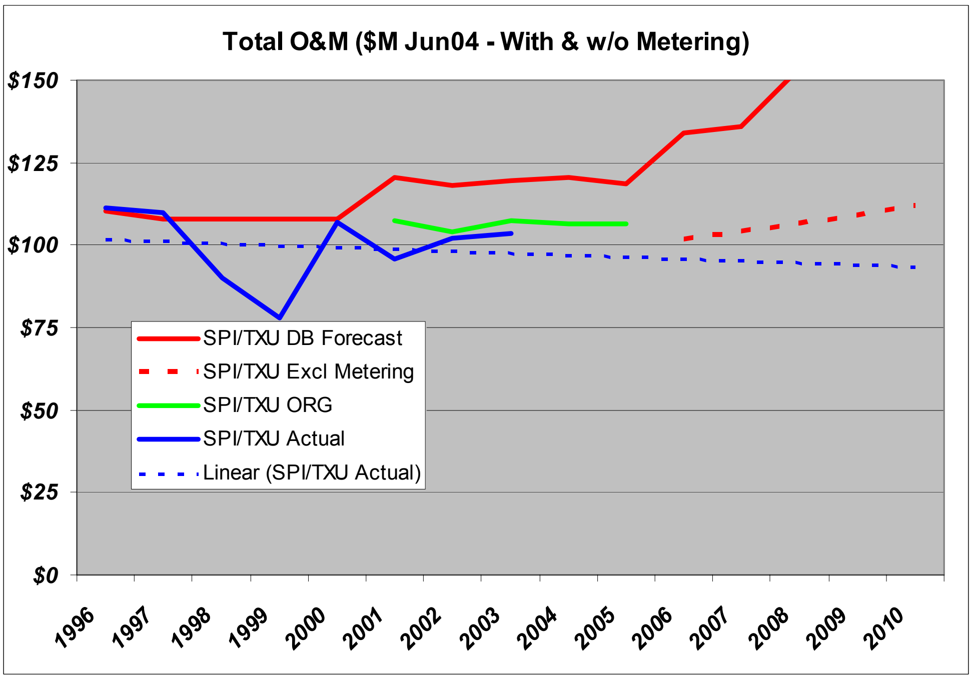

FIGURE A.9 TXU/SPI OPEX PERFORMANCE

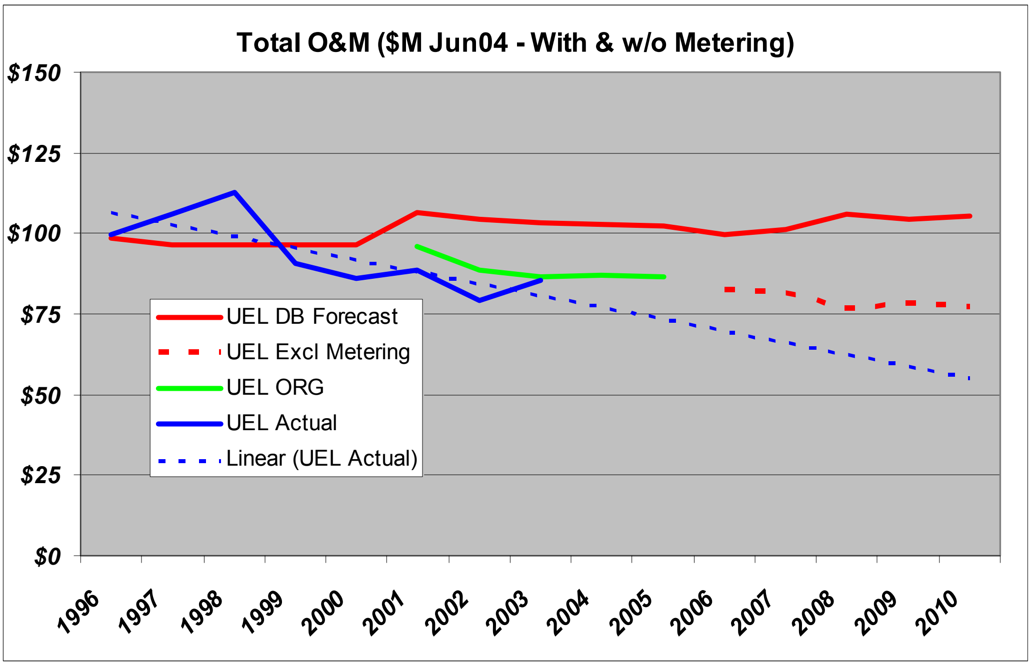

FIGURE A.10 UNITED ENERGY OPEX PERFORMANCE

Appendix B: WACC Comparisons

Industry-Jurisdiction	Regulatory Decision		WACC PARAMETER							
			Cost of debt		MRP	Equity beta	Post-tax RoE		Post-tax WACC (Vanilla)	
			Nom	Real	Nom		Nom	Real	Nom	Real
ELECTRICITY - AUS	IPART 1999 ED (Mid)	(Mid)	7.50%	*4.37%*	5.50%	0.960	12.00%	*8.64%*	*9.30%*	*6.08%*
	SA EPO 1999 ED (Mid)	(Mid)	6.76%	4.15%	6.50%	1.015	12.24%	9.00%	*9.23%*	*6.52%*
	ACCC 2000 ETN (Mid)	Transgrid (Mid)	7.81%	*4.52%*	6.00%	1.015	**12.88%**	*9.43%*	*9.84%*	*6.49%*
	ORG 2000 ED		*7.73%*	5.00%	6.00%	1.000	*12.19%*	9.50%	*9.51%*	**6.80%**
	QCA 2000 ED		7.01%	*4.83%*	6.00%	0.710	9.62%	*7.39%*	**8.05%**	*5.85%*
	ACCC 2001 ETQ	PowerLink	6.85%	*4.43%*	6.00%	1.000	11.80%	*9.12%*	**8.83%**	*6.30%*
	ACCC 2002 ETS	Electranet SA	6.39%	*4.23%*	6.00%	1.000	11.17%	*8.92%*	**8.30%**	*6.11%*
	ACCC 2002 ETV	SPI PowerNet/VENCOR	6.32%	*4.19%*	6.00%	1.000	11.09%	*8.90%*	**8.23%**	*6.08%*
	OTER 2003 ED		6.30%	*4.12%*	6.00%	0.950	10.75%	*8.48%*	**8.08%**	*5.87%*
	ACCC 2003 ETT	Transend	6.77%	*4.35%*	6.00%	1.000	11.84%	*9.32%*	**8.80%**	*6.34%*
	ICRC 2004 ED		6.80%	*4.53%*	6.00%	0.900	11.10%	*8.66%*	*8.52%*	*6.18%*
	ACCC 2004 ETN	TransGrid (Draft)	6.76%	*4.22%*	6.00%	1.000	11.87%	*9.22%*	**8.80%**	*6.22%*
	IPART 2004 ED (Mid)	(Mid)	7.00%	*4.39%*	5.50%	0.945	11.20%	*8.39%*	*8.68%*	*5.99%*
	ERA 2005 ED	(Draft)	6.45%	*3.80%*	6.00%	1.000	11.33%	*8.56%*	*8.40%*	*5.71%*
	ESCoSA 2005 ED		7.40%	4.90%	6.00%	0.800	10.60%	8.00%	*8.68%*	*6.13%*
	QCA 2005 ED		*6.83%*	*3.96%*	6.00%	0.900	11.01%	*8.03%*	**8.50%**	*5.59%*
GAS - AUS	IPART 1997 GD (Mid)	(Mid)	9.00%	*6.34%*	7.00%	0.740	10.88%	*10.22%*	*9.94%*	*8.28%*
	ACCC 1998 GTV	TPA	7.20%	4.60%	6.00%	1.200	**13.20%**	10.40%	*9.60%*	*6.94%*
	ORG 1998 GD		*7.20%*	*4.59%*	6.00%	1.200	13.20%	10.40%	*9.60%*	*6.93%*
	OFFGAR 2000 GD		*7.47%*	*4.56%*	6.00%	1.080	12.70%	9.70%	9.60%	6.60%
	IPART 2000 GD (Mid)	(Mid)	7.44%	*4.48%*	5.50%	1.000	12.00%	*8.86%*	*9.26%*	*6.23%*
	QCA 2001 GD		7.51%	*4.89%*	6.00%	0.990	11.90%	*9.17%*	**9.27%**	*6.60%*
	ESC 2002 GD		7.40%	*5.09%*	6.00%	1.000	11.80%	9.40%	*9.16%*	**6.80%**
	ACCC 2002 GTV	GasNet	6.90%	4.63%	6.00%	1.000	11.15%	8.80%	*8.60%*	**6.30%**
	OFFGAR 2003 GT	EPIC DBNGP	*6.48%*	*4.14%*	6.00%	1.200	12.48%	10.00%	*8.88%*	*6.48%*
	ICRC 2004 GD (Mid)	(Mid)	6.75%	*4.08%*	6.00%	0.995	11.38%	*8.59%*	*8.60%*	*5.88%*
	IPART 2004 GD (Mid)	(Mid-Draft)	6.55%	*3.95%*	6.00%	0.900	10.85%	*8.10%*	*8.27%*	*5.61%*

Industry-Jurisdiction	Regulatory Decision		WACC PARAMETER							
			Cost of debt		MRP	Equity beta	Post-tax RoE		Post-tax WACC (Vanilla)	
			Nom	Real	Nom		Nom	Real	Nom	Real
WATER -AUS	IPART 2000 W&S (Mid)	(Mid)	7.30%	*4.39%*	5.50%	0.835	11.10%	*7.99%*	*8.82%*	*5.83%*
	GPOC 2001 BW (Mid)	(Mid)	6.44%	*4.07%*	6.00%	0.773	10.37%	*7.91%*	*8.41%*	*5.99%*
	QCA 2003 RW	Burdekin	*7.97%*	*5.34%*	6.00%	0.400	*8.57%*	*5.92%*	**8.27%**	*5.63%*
	IPART 2003 W&S (Mid)	(Mid)	5.95%	*3.67%*	5.50%	0.775	9.45%	*7.01%*	*7.35%*	*5.00%*
	ICRC 2004 W&S (Mid)	(Mid)	*6.87%*	*4.60%*	6.00%	0.900	*11.02%*	*8.66%*	*8.53%*	*6.22%*
	GPOC 2004 W (Mid)	(Mid)	6.23%	*4.00%*	6.00%	0.773	10.17%	*7.86%*	*8.20%*	*5.93%*
	QCA 2004 W&S	Gladstone	6.77%	*4.17%*	6.00%	0.640	*9.25%*	*6.59%*	**8.02%**	*5.38%*
	ESC 2005 W&S	(Draft)	*6.31%*	*3.71%*	6.00%	0.750	*9.71%*	*7.03%*	*7.67%*	**5.10%**
OTHER - AUS	IPART 1999 Rail (Mid)	(Mid)	6.37%	*4.50%*	5.50%	0.850	10.06%	*8.11%*	*8.03%*	*6.12%*
	QCA 2004 Ports	Dalrymple	*7.14%*	*4.45%*	6.00%	0.660	*9.80%*	*7.04%*	**8.20%**	*5.48%*
ELEC - UK	OFFER 1994 ED (Mid)	(Mid)	*5.98%*	3.90%	3.75%	0.550	*7.46%*	**5.35%**	*7.30%*	**5.20%**
	UKCC 1994 ED	(SHE Appeal - Mid)	*6.23%*	4.15%	4.00%	0.575	*8.11%*	**5.99%**	*7.96%*	**5.84%**
	OFGEM 1999 ED		*6.86%*	4.30%	3.50%	1.000	*8.56%*	6.00%	*7.71%*	*5.11%*
	OFGEM 2000 ET	NGC	*7.02%*	4.45%	3.50%	1.000	*8.82%*	6.25%	*7.74%*	*5.14%*
	OFGEM 2004 ED		*7.22%*	**4.10%**	*3.50%*	*0.800*	*8.50%*	**7.50%**	*7.77%*	**5.50%**
GAS - UK	OFGEM 2001 GT&D	Transco	*7.02%*	4.45%	3.50%	1.000	*8.82%*	6.25%	*7.69%*	*5.09%*
WATER - UK	OFWAT 1994 W&S	(Mid)		4.50%	3.00%			6.00%		**5.50%**
	OFWAT 1999 W&S (Mid)	Large W&SC (Mid)	*7.37%*	*4.50%*	3.50%	0.750	*8.20%*	***5.30%***	*7.79%*	**4.75%**
	OFWAT 2004 W&S (Mid)	(Mid)	*6.89%*	3.85%	4.50%	1.000	*10.39%*	7.25%	*8.47%*	**4.75%**

Notes:

- Figures shown in *red italic font* have been estimated using parameter values taken from regulators' decisions.
- Figures shown in **bold font** are parameters/WACC values adopted in regulators' decisions.
- Figures shown in normal font are parameters/WACC values quoted in regulators' decisions.
- Where regulators quote ranges for parameter values, a mid-point value has been used.