Comments on Draft National Framework

For

Electricity Distribution

By

The Major Energy Users Inc

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Executive Summary

The Major Energy Users Inc. (MEU) welcomes the opportunity to provide comments on the proposed changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of distribution network businesses.

The MEU is very disconcerted by the approach taken of seeking to "build on" the AEMC's approach to economic regulation of transmission. The AEMC's transmission revenue Rules determination was a very poor and biased outcome and has decisively favoured the economic interests of TNSP's.

The two areas of most concern – the high WACC parameters prescribed and no requirement for ex-post audits of past capex and opex – open the floodgates for gaming and profiteering by TNSP's.

By adopting the AEMC approach, the SCO is magnifying the mistakes made by the AEMC, at the expected large cost implication for consumers.

This submission provides the MEU's views on:

- The AEMC's Electricity Transmission Revenue and Pricing Determinations
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1. INTRODUCTION

The Major Energy Users Inc (MEU) welcomes the opportunity to comment on the proposed changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution.

The MEU comprises major energy using companies who are members of the Energy Markets Reform Forum (NSW), the Energy Consumers Coalition of South Australia, the Energy Users Coalition of Victoria, the A3P and the Cement Industry Federation.

Electricity distribution costs can represent up to 30-35% of major energy users' landed cost of electricity and therefore can have a major influence on the competitiveness of MEU members' industrial activities. Distribution service performance and reliability are also critical to the operations of MEU members. Outages and dips in electricity flows can have major disruptive impacts on production, leading to lost production and/or causing damage to capital equipment.

Overall, MEU members and most other consumers see that the cost of power is critical, but that this must also be assessed in terms of the quality of supply, its reliability and the sustainability of supply over the long term. These reflect the nature of the investments made by consumers, regardless of whether these investments are for large manufacturing enterprises or at the other end of the scale investments made by residential consumers.

Whilst it is easy to see that a large manufacturing business makes investment decisions based on an assumption there will be a certainty of long term electricity supply, so too does a residential consumer when making decisions about the relative merits of (say) electric cooking over gas cooking. Once this decision is made, the residential consumer has a high cost (in relation to its investment) to make a later change.

Accordingly, the MEU considers that the proposed regulatory framework for the economic regulation of electricity distribution must be consistent with the National Electricity Law Objective, viz "…….in the long term interests of consumers", which applies to all consumers – residential, commercial and industrial. This submission by MEU does not seek to only represent industrial consumers, although this comprises its membership base. The MEU recognises that in regard to this issue of amending the electricity distribution Rules, all consumers are impacted by changes and it makes little difference whether the consumer has a large flat consumption pattern or a small peaky consumption pattern – the investment made by each consumer is predicated on low cost, high quality, reliable and sustainable electricity supplies.

It should be recognised that the cost of electricity distribution services for small consumers is the largest element of the cost of delivered power, whereas for large consumers, it is more likely to be the second largest element of the delivered cost. Additionally the loss of supplies which would be felt by all consumers is predominantly due to a failure in the distribution network.

The MEU, therefore, points out that its comments relating to this review are driven by a recognition that electricity distribution has the greatest impact on costs and quality of all the elements in the electricity supply chain.

From the MEU's perspective, the key outcomes from the proposed regulatory framework must be to deliver **cost reflective** and **economically efficient electricity distribution services.** The MEU seeks a distribution system that is:-

- economically efficient
- cost reflective
- sustainable in the long term
- able to grow to meet consumer needs
- certainty of supply when needed
- secure in the long term
- reliable
- delivering acceptable quality.

In return, the MEU supports the asset owners having:-

- a sustainable and adequate return earned by distribution network businesses
- economically efficient incentives for service improvements

The changes to the Rules will affect the level of prices, which provide signals for (large) investments by consumers. They should also affect incentives:-

- to ensure pricing is cost reflective
- to provide equitable pricing signals
- for providing signals to embedded generation and demand side responses
- for ensuring adequate reliability and quality of supply.

2. The AEMC's Electricity Transmission Revenue and Pricing Determinations

The MEU is somewhat disconcerted by some aspects of SCO's commentary in the Explanatory Material referencing the AEMC's approach to the transmission revenue and pricing Rules, viz:-

> "*To achieve the MCE's objective of consistency where appropriate, the Exposure Draft of distribution revenue Rules largely builds on the AEMC's approach to economic regulation of electricity transmission. The Exposure Draft takes into account differences in the nature of transmission and distribution networks, based on analysis of these differences undertaken during the development of the draft Rules.*
>
> *The exposure draft distribution pricing rules are less prescriptive than the transmission pricing rules. The draft distribution pricing rules articulate a number of principles based on economic efficiency. The rules provide flexibility for the distribution network service provider to nominate in a pricing proposal to the AER tariff classes, the charging parameters for those tariff classes and assign values to those charging parameters and demonstrate compliance with the pricing principles and the rules. The rules will also contain side constraints which will limit the average increase for the tariff class." (Pages 5 and 6).*

The MEU's concerns are as follows:-

- Consistency between transmission and distribution revenue rules are certainly supported where appropriate, and as stated in the Explanatory Material, the Exposure Draft takes into account differences in the nature of transmission and distribution networks. However, achieving consistency for consistency's sake is grossly erroneous. The AEMC's recent transmission revenue Rules and approach took a decisive step in biasing the Rules in favour of TNSPs, apparently predicated on the unproven assumption that TNSPs required more incentive to invest in their networks. The prescription of the major WACC parameters at the high end of the possible range, and the decision not to require an ex-post audit of past capex and opex, opens the door to injecting large revenue gains to TNSPs. It was a very poor regulatory outcome.

- The AEMC has made fundamental changes to the Rules which provide a specific bias in favour of TNSPs that will have significant cost impacts for consumers:-

    1. Preventing the AER from assessing the WACC parameters to reflect prevailing financial conditions
    2. Automatic roll in of actual capex, regardless of it being demonstrably efficient and prudent

3. Assessing capex on an ex ante basis only giving the AER no ability to optimise inefficient or imprudent investments
4. Allowing TNSPs to set their own depreciation, permitting the transfer of liability for asset provision to/from future generations to allow TNSPs to optimise their profitability
5. There is no incentive on a TNSP to connect new consumers to reduce the costs to others
6. There is no incentive to invest where the need is
7. There is now a strong incentive to invest where the penalty/bonus will apply
8. There is no incentive to dedicate opex and capex to needs if this doesn't impact on measured performance
9. There is a positive incentive to devote opex and capex to areas where the bonus can be increased

- Appendix A contains the MEU's analysis of the equity market's assessment of the AEMC's revenue Rules determination. Blindly following the AEMC's approach will mean that the draft distribution Rules will **magnify** the adverse impacts on end users already stemming from the AEMC's erroneous approach on transmission revenue. Poor Rules making by the AEMC must not lead to the enactment of further poor Rules, under the guise of "consistency".

- The Exposure Draft does not sufficiently recognize the important differences between transmission and distribution networks in some key areas. For example, in setting the RAB in the Rules, as well as the roll-forward approach using actual capex and depreciation there is a need to recognise that:

  - with TNSPs there are few but large projects involved, thereby allowing some form of ex ante review of forecast expenditure
  - but with DNSPs, the many projects involved prevent ex ante assessment of forecast expenditure, thereby making an ex-post review of past expenditure even more important, in order to minimize the inevitable gaming by DNSPs.

As for the Exposure Draft's pricing rules being "less prescriptive than the transmission pricing rules", thereby providing more flexibility to the DNSPs to nominate tariff classes, etc, this opens up a vast area for more 'gaming' by DNSPs. Moreover, there is neither incentive for the DNSPs to set pricing signals for efficient demand nor is there any signal for cost reflectivity.

The DNSP's have no incentive to get prices to be cost reflective. The main focus is on maximizing revenue and profitability. As examples of the poor AEMC Rules determination the AEMC's approach in its transmission revenue Rules determination actually results in providing:

- no locational signals to incumbent large generators and very little to new large generators
- a free ride to non-firm (e.g. wind) generation which adds significantly to the capacity needs of the network (yet provides a very low utilisation factor which NEMMCo asserts is 25% only)
- negative locational signals to small, self and embedded generators
- direct connected customers are the only consumers facing locational signals, as consumers embedded in the distribution networks get standard tariffs which have no regard for location, only classes of usage, although it is noted that very large consumers can require their DNSP to provide the transmission cost element of the network service cost
- no analysis to identify the consumer impacts in any of the high level revenue allocation assumptions
- the use of Baumol-Willig (costs to be between avoided costs and stand-alone costs) as the band width for cost reflectivity is too wide and easily used to bias one customer class over another
- the TNSP is given the flexibility to apply Baumol-Willig, thereby allowing for discrimination, with the AER given little scope to verify a fair allocation of costs
- little scope for the AER to assess issues on a holistic basis, thereby limiting the AER's regulatory flexibility.

In short, the AEMC revenue Rules:-

- are unbalanced and are to the substantial disadvantage of consumers
- lack empirical analysis and evidence
- provide too much power to TNSPs to exercise
- straight-jacket the AER
- ignore issues brought up by consumers
- do not resolve issues under the previous Rules

The results of the AEMC revenue Rules determination are:-

- higher transmission network prices
- no pressure on generation to locate where it is needed
- little reliability and investment incentives where needed
- over-investment and gold-plating
- just what the financial engineers want

The inadequate work by AEMC in setting the Rules for transmission revenues has resulted in excessive attention given by consumers in addressing the preparation of the AER guidelines for transmission reviews in order to minimise the ability of the TNSPs to maximise profitability to the detriment of consumers. But these efforts are heavily constrained by the AEMC Rules.

It is, however, important to note that in the AEMC changes to transmission pricing Rules, the AEMC tacitly accepted (after considerable interactions with the MEU) that pricing plays a major part in providing signals to consumers. As a result the AEMC determined that demand is the critical element driving investment in a network, and that therefore demand (and not consumption) had to be the basis for pricing of TUoS charges.

Initially the AEMC had decided that other pricing elements should be left to the TNSP to determine. After extended debate, the MEU convinced the AEMC that pricing was effectively an issue for consumers, and that consumers should have a major say in determining the manner of recovery of the revenue allowed to TNSPs, as TNSPs had little or no incentive under a revenue cap to ensure that the prices they set were key elements in securing cost reflectivity and signals to consumers to encourage better utilisation of the networks.

This is a very important pricing approach adopted and determined by the AEMC, and should form the basis for Rules setting for distribution network businesses.

3. Major concerns of the regulatory process

1. Illustration of Gaming by DNSPs

The MEU provides the following to illustrate the ease at which DNSPs can game the regulatory pricing review process to boost revenues. "Less prescriptive" and "more flexibility" in regulatory Rules increase the risks for consumers.

The MEU notes that there are effectively three elements of cash flow that impact the PTRM model used to set regulated revenues/prices. These are the cash flows for price caps, opex and capex.

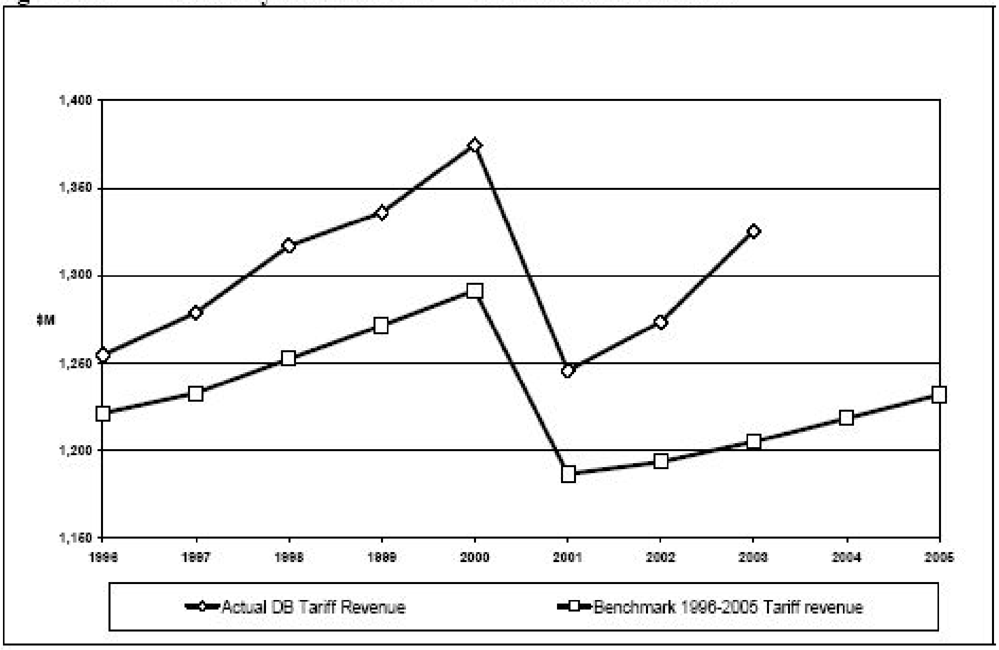
Price caps – currently consumers pay for the use of DNSP assets on a monthly basis. The amount paid each month is based on the same inputs and varies only with the amount of power taken each month. Revenue raised is expected to match the annual revenue permitted by the regulator. By careful selection of specific prices which build the "basket of prices" the DNSP can increase revenue despite there being no apparent change in demand and is adjusted each year for any "unders and overs" incurred in the previous year.

In the review of electricity DNSPs in 2005, MEU affiliate EUCV noted in its response to the ESCoV Position Paper on Electricity Distribution Price Review (EDPR) March 2005 that:-

"…there was a significant over-recovery of revenue through the tariff allocation as the following figure shows[1]:-

[1] ESCoV EDPR Position Paper figure 1.5

Figure 1.5: Industry tariff revenue — actual and benchmarks

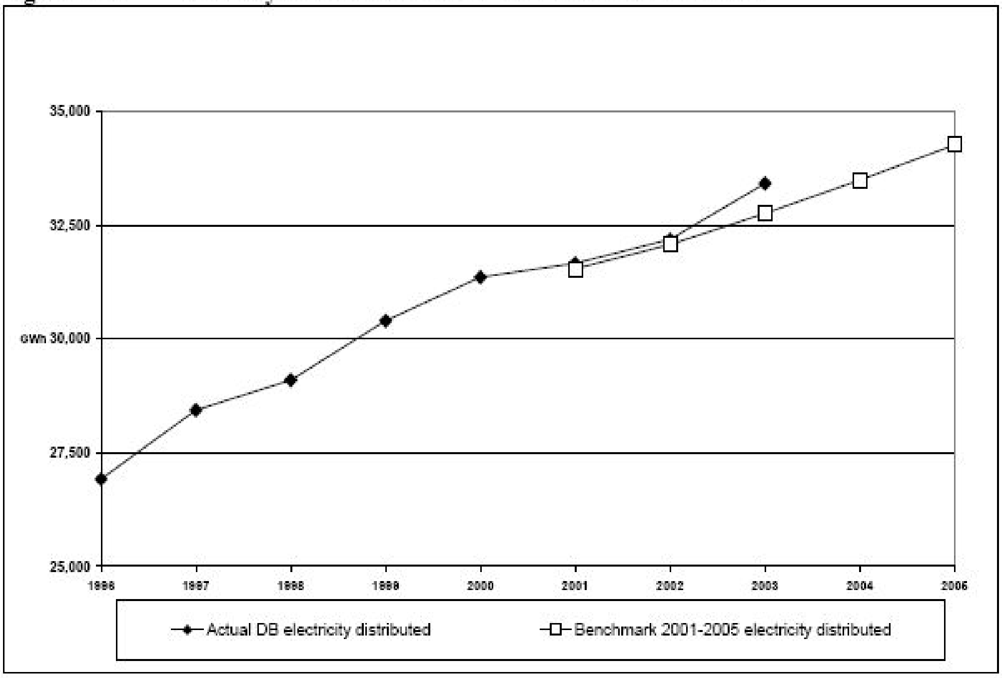


This demonstrates that by re-balancing (read: manipulating) tariffs, the DBs can and did increase their revenue. The Electricity Code requires there be cost reflective allocation of costs to each customer class, but as there has been a significant over-recovery, then some customers must have been over-charged for the service provided."

Some of this over-recovery of revenue was attributable to increases in demand and consumption and a price cap is intended to incentivise a DNSP to seek increases in these parameters so that overall, prices to consumers fall. But the ESCoV provided evidence[2] that this was not the case, and that little of the revenue over run was attributable to un-forecast growth in consumption

[2] ESCoV Position paper figure 1.4

Figure 1.4: Industry GWh distributed — actual and benchmarks



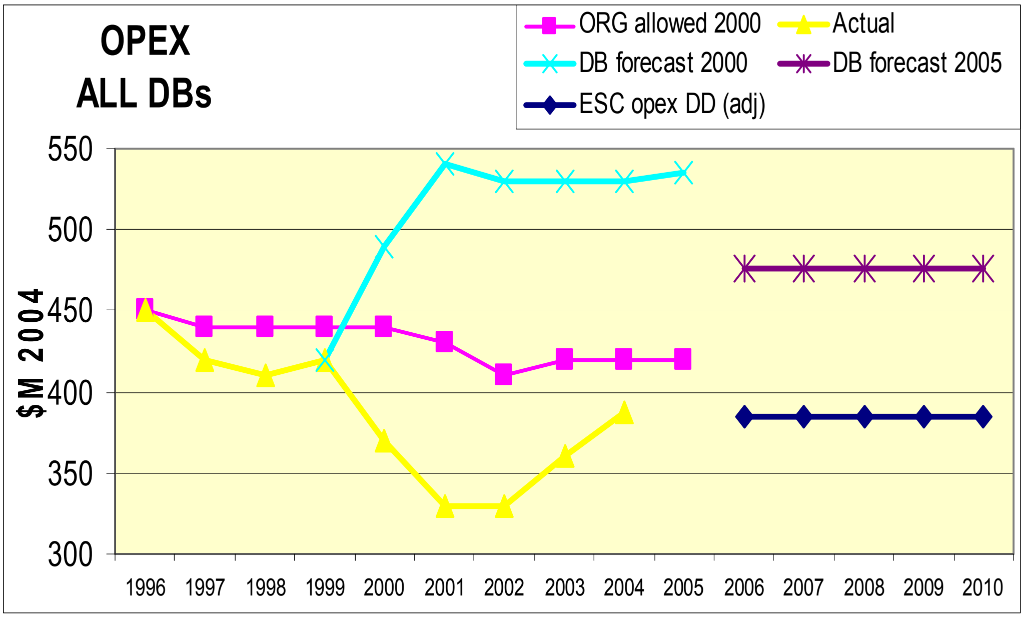
As a result, the ESCoV noted[3] that

"...the Commission has concluded that there would be benefit in developing a structured framework and process for increasing the transparency of the distributors' tariffs and the basis for changes to their tariffs over time."

Opex – the DNSP is assumed to expend its opex on a consistent basis throughout a year and to reflect the amount of opex permitted by the regulator for each year. In fact, it has been readily observed that opex tends to be under spent in the early years and overspent in the latter years of a regulatory period.

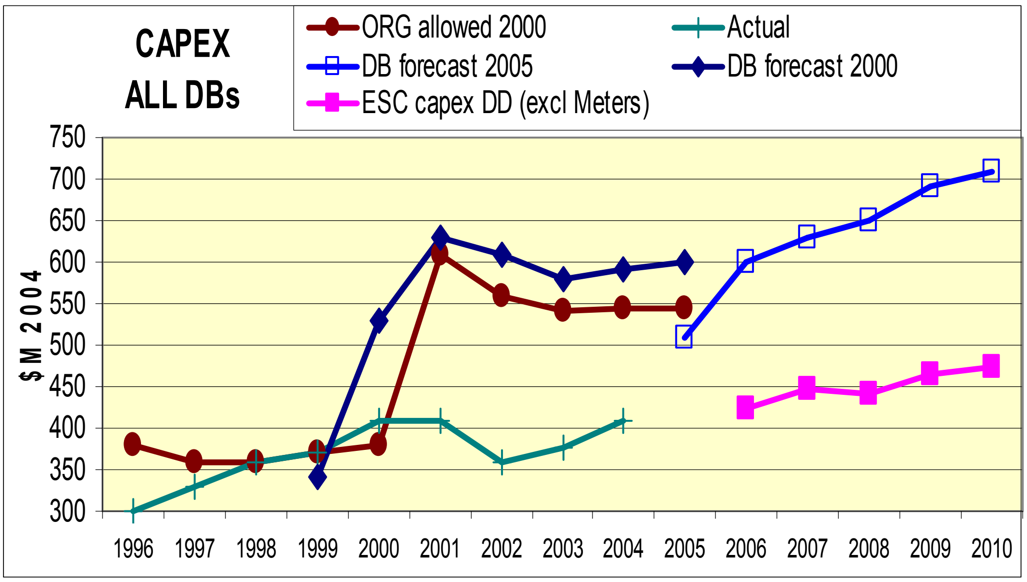
To demonstrate this, the following charts show the opex claims and the actual expenditures incurred since 1995 for all the electricity distribution companies in Victoria. This clearly shows the way regulated businesses seek to manipulate the regulatory environment.

[3] ESCoV Position Paper page 181



Source: ESC Victoria

Capex – the DNSP is assumed to expend its capex on a consistent basis throughout a year and to reflect the amount of capex permitted by the regulator for each year. In fact, as with opex, it has been readily observed that capex tends to be under spent in early years and overspent in the latter years of a regulatory period. The equivalent chart to the one on opex shows a similar approach.



Source: ESC Victoria

Opex and Capex – One very clear observation in preparing these charts by EUCV was to highlight not only the early year under-runs in opex and capex, but to demonstrate that a DNSP is incentivised to request the maximum opex and capex in a review, despite a very real outcome that they have not even spent the lesser amounts permitted by the regulator.

The ESCoV commented that the approach used by the regulator for the Victorian DBs has resulted in lower opex and capex costs in the subsequent period. Whilst the ESCoV has been able to justify much lower opex and capex in the subsequent period than was requested by the DBs it is quite clear that the DNSPs have been able to retain the full benefits of the early period under-runs without having to share these with consumers at all.

There is easy potential for regulated distribution network businesses to manipulate their opex and capex spending within the regulatory period in order to achieve three outcomes, viz

1. increased cash flow benefits from under spending in the early years,
2. maximizing the ability to recover "efficiency" benefits by implying the early years under spends were unsustainable as apparently higher expenditures were required in the latter part of the period, and
3. setting an expectation for the next reset by having large opex and capex amounts in the later years to set a new benchmark for the next regulatory period (which puts pressure on regulators to approve forecast expenditures sought).

At the same time, DNSPs seek to ensure that the revenue tends to be on the high side of permitted revenues, as this provides a cash flow benefit to the DNSP, despite there being an interest impact for any under/over recoveries.

Therefore, the MEU has a concern that to take an approach which attempts to balance the impact of price caps, opex and capex is likely to disadvantage consumers, as the DNSPs will seek, and are capable of using, any approach to their advantage. Providing 'flexibility' to DNSPs in their pricing methodology and approach will ensure this happens.

There is one element of the AEMC view on pricing of transmission services that should be identified – under a **revenue cap**, TNSPs have little incentive to provide cost reflectivity of prices or to provide price signals to consumers to better utilize the assets provided by TNSPs.

In this regard the same can be said of DNSPs under a revenue cap approach. This lack of incentive equally applies to DNSPs using a price cap. There is still no incentive to ensure that the prices set are cost reflective or provide consumers with better signaling.

What a price cap arrangement does is to incentivise DNSPs to encourage consumers to use the network more, rather than to better utilize the network. It also encourages a DNSP to manipulate prices so that increased revenue results.

A price cap arrangement encourages a DNSP to seek greater consumption of power – an issue that is at odds with government policies on greenhouse emission management. Further, a DNSP operating under a price cap has an incentive to increase demand by consumers in order to justify increased augmentation of the network.

In this regard it is intriguing to note that for much of the decade since deregulation, DNSPs were actively encouraging the use of residential refrigerative air conditioners, even to the extent of offering cash incentives to consumers to do so. Fortunately this practice seems to have reduced markedly in recent years, but as a result of the earlier encouragement, the penetration of this type of air conditioning by residential consumers is very high[4].

The MEU, therefore, considers that leaving pricing policy to DNSPs is not an effective control mechanism as the incentive on a DNSP to get cost reflective pricing or to provide adequate signals is either non-existent (under a revenue cap) and provides an incentive to manipulate tariffs to increase revenue.

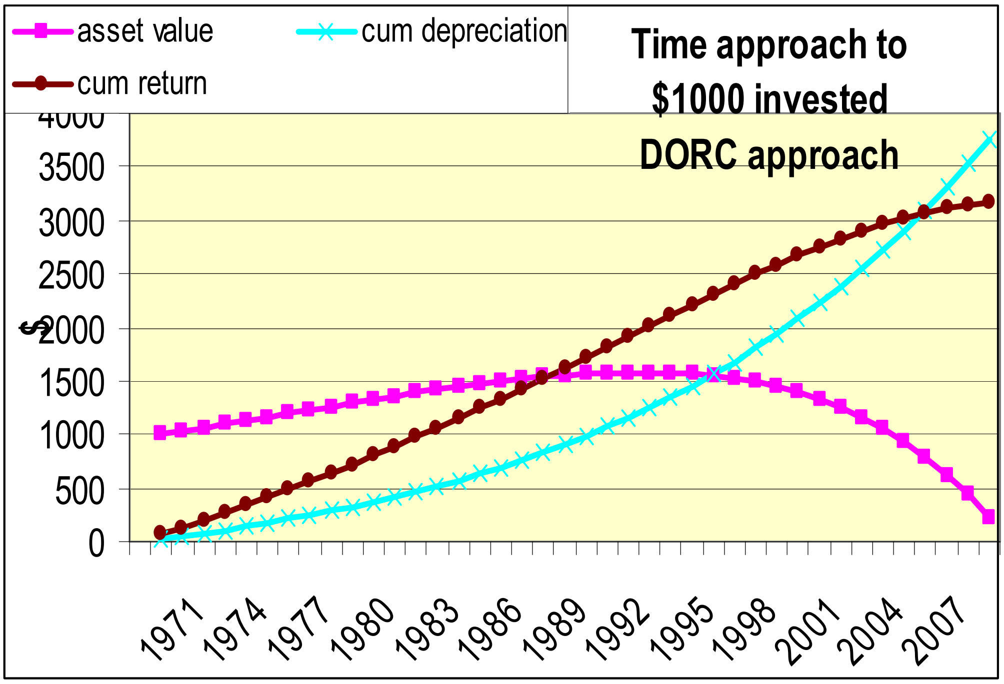
2. Depreciation

The regulatory approach to depreciation provides a significant cash windfall to DNSPs.

Consider the following example:-
Investment of as asset valued at $1000
Depreciation over 40 years
Gearing at 60% debt, Debt premium 150 basis points, MRP 6%,
CPI at average of last 40 years at 5.88%
Average bond rate for last 40 year of 8.82%
Nominal WACC becomes 12.12% and “real” WACC is 6.24%

The return, RAB and accumulated cash over 40 years can be seen as shown in the following chart.

[4] ESCoSA observed during its review of the ETSA reset, that the penetration of air conditioning in SA residences probably exceeded 90%



This shows that there is no residual value for an asset that is no longer useful but the payments made by users have been incurred earlier in the regulatory period. The amount paid for the use of the asset (ie RAB* WACC) is $3,157, and the amount paid in depreciation is $3,754. This means that the user would have paid $6,911 for use of the asset over the 40 years.

Regulatory costs allowed	
Initial investment	$1,000
Period of investment	40 years
Depreciation rate	2.5%
Payment for depreciation (recovery of investment)	$3,754
Residual value of investment	$0
Payment for use of investment	$3,157
Total payment for use and recovery of the investment	$6,911
Required annual fixed payment for use of $1000 investment for 40 years	$173
Effective interest rate[5]	17.3%

This shows that the regulated business recovers an annual payment of $173 per year for the life of the asset. The effective interest rate of

[5] This is the interest rate that would be paid for use of funds with the principal being paid back at the end of the period.

17.3% includes a return on investment of 12.2% nominal (ie nominal WACC).

This nominal return on investment rate can be compared to the average housing purchase interest rate which over the past 40 years has averaged 9.63%. As a housing loan is based on 60% to 80% debt, it needs to be adjusted for an equity return on the balance. Using 60% debt gearing, a comparable nominal WACC is 11.43%.

As the annual payment is at the rate of 17.%, and the return (WACC) is 12.2%, the element of the return on capital (ie depreciation) is the difference or 5.1%.

The imputed return of capital is 2.5% ie the amount needed for each of 40 years to return 100% of the investment. On average the regulator permits the business to recover depreciation at twice the rate assumed to apply.

It is alleged that this over recovery is attributable to inflation on the amount allowed for depreciation over the 40 years. This allegation has not been demonstrated as correct nor is it proven to reflect the reality in a competitive enterprise. **Many MEU members advise that they do not ever recover a full return of investment (ie depreciation) and that the lack of the recovery is an element of the business' overall profitability.**

If this is the case then the development of the market risk premium (MRP) incorporates an element of depreciation as MRP is derived from the dividends provided by listed businesses combined with the growth in value of the business as registered by the ASX – effectively the MRP derives from the changes in the ASX accumulation index.

The purpose of attempting to identify where this over-recovery of rewards is derived from for regulated businesses, is found in the conclusions of Appendix A to this submission. It is quite clear that not only have values of the regulated businesses (as seen by the utilities index) grown out of proportion to the market as a whole, but the dividends provided by the businesses have consistently shown premium to the market average.

The work above recognises that depreciation as paid to regulated businesses by consumers is different to that amount which is incorporated in the accounts of businesses in competition, or indeed as permitted for taxation reasons by the Australian Taxation Office.

4. Comments on the detailed changes

Part A – Introduction

6.1.3 Meaning of terms and conditions of access for distribution services

(a) With respect to "negotiated distribution services" we enquire whether "other terms and conditions" would capture those negotiated services which arise from "capital contributions" by end users. If not, then these services should be spelt out.
(b) The above comment applies equally to "direct control services" which may arise from "capital contributions" by end users.

6.1.4 Access to direct control services and negotiated distribution services

(3) Does the specification "a person who is provided direct control services or negotiated distribution services…….must not engage in conduct for the purpose of preventing or hindering access to those services" prevent that person from seeking by-pass arrangements or in doing so, prevent other users from obtaining access to the services as they may no longer be economic to supply? If not, then it should be made clear in the Rules.

Merits reviews at Law

The MEU notes that the new Rules allow a "small" consumer to be exempted from being awarded costs relating to a merits review. This is inequitable.

The reason propounded is that the risk of costs would most likely prevent a small consumer from using this avenue of seeking equity. It is noted that a decision in favour of consumers sought by a large consumer would most likely have impact on all consumers, yet the large consumer is exposed to costs being awarded against it.

There have been very few appeals (perhaps 1 or 2 at most) initiated by consumers in relation to energy regulatory matters.

In counter to this regulated businesses have been consistent appellants seeking changes to specific elements of a decision, based on getting adjustment to only those elements of a decision they dislike. The cost to likely benefit resulting from an appeal is heavily in favour of the regulated business. For example the cost to appeal a 0.1% adjustment in equity beta is very low compared to the revenue the business will receive if the appeal is successful. These costs are ultimately paid by consumers, so there is a very high reward to risk benefit faced by network businesses.

The risk to even a single "large" consumer fails to compare to the rewards a regulated business will receive. In such a case the benefits of an appeal by the large consumer will flow to all consumers. In such a case the large consumer is at risk of incurring costs when the benefit will flow to more than just the single consumer appellant.

With this in mind, it is recommended that the Law and Rules be amended to prevent costs being awarded to any consumer appellant (regardless of size) if the benefits of the appeal would go to more than the businesses or person appealing the decision.

Part B – Classification of Distribution Services and Distribution Determinations

6.2.1 Classification of distribution services

The current draft Rules assign powers to the AER to classify distribution services and in doing so, to have regard to a range of factors. This is endorsed.

However (c) then specifies that the Rules may over-ride the AER (and its processes) by requiring a particular classification be assigned to a distribution service of a specified kind. This can lead to forum shopping and is not supported. It should be sufficient for the Rules to specify that there should be an AER process to review classification of various kinds of distribution services. There should not be a two forum process.

There are proposed to be three types of classification of DNSP services – direct control, negotiate/arbitrate, and unregulated. It was suggested at the recent public forum there might be a need for a fourth type of service lying between negotiate and unregulated.

The MEU members have experienced times when a DNSP alleges that a service requested is competitive and therefore unregulated. When the consumer approaches other potential suppliers of the service it is found in practice there is competition in the construction of the works but little or no competition in regard to the operation and long term maintenance of the service. This matter was identified by the AEMC in its review of transmission services, and it provided for the potential that in practice the local TNSP was the only potential provider, effectively making provision of the service a monopoly. Chapter 6A allows for there to be arbitration (at the direction of the AER) in this eventuality to ensure that there is no exercise of monopoly powers.

With this in mind, the MEU recommends that there be a right for a consumer to request the AER to identify if a service required is in fact competitive, and if not, for the AER to arbitrate to ensure that the DNSP does not use its effective monopoly position to the detriment of the consumer.

DNSPs allege that they currently only provide two basic services – direct control and unregulated, and there are no negotiated services. The MEU sees that it is the identification of what is truly competitive rather than apparently competitive which needs to fall into the negotiate/arbitrate category. Thus whilst there might not be a fourth type of service, it would be the expansion of the negotiate/arbitrate service (currently not used by DNSPs) which provides consumers with some ability to match the decision of a DNSP to determine if a service provision is truly competitive.

6.2.2 Classification of direct control services as standard control services or alternative control services

(b)(2) With respect to the "possible effects of the classification on administrative costs of the AER, the Distribution Network Service Provider and users or potential users" we believe this clause should be more broadly restated as a cost/benefit test, which, inter alia, encompasses administrative costs and other costs (e.g. cost of the services) of end-users and potential users.

(c) Again there is a concern that providing the Rules with the ability to classify any service and hence over-ride the AER and its processes (as specified under the Rules) will lead to forum shopping and negate the Rules-prescribed role of the AER.

6.2.8 Guidelines

(a)(3) Is the reference to "avoidable" costs really "avoided" costs? If so, please make the amendment.

The detail of this clause is that the AER ***may*** publish guidelines in relation to any matter covered by chapter 6. It is essential that all parties involved in matters determined by the AER should be aware of what the AER requires in relation to carrying out its tasks, and of how the AER intends to address its responsibilities.

The MEU considers that, as with AER responsibilities under chapter 6A, it should be required to prepare guidelines so that the businesses being regulated know how to provide information with their applications, and for Interested Parties to know the basis on which information is to be provided.

It is noted that these guidelines would not be binding on DNSPs, but it should be stated clearly that non compliance with a guideline could well result in a DNSP having to provide additional information sufficient for the AER to properly make its determination.

Part C – Revenue Regulation for Standard Control Services

6.4 Post-tax revenue model

The MEU agrees that there be a single approach to setting revenue. Each of the processes used have minor differences, yet the outcome for consumers paying the costs should be the same regardless of the model used.

What is of concern in the PTRM approach is that the AER will have to assess the amount of tax that a regulated entity will incur, and to add this to the allowed revenue. Not all DNSPs have the same ownership structure, or the same approach to developing their taxable income. In particular, the approach to depreciation for tax purposes varies considerably, as does the remittance of fees for services provided by owners[6].

As a result of different approaches to payment of taxation used by different entities, it should not be consumers that are required to pay the tax determined by the entity. There is a basic assumption that consumers should be totally independent of the way the business conducts its affairs. This is the basis on which the WACC elements are determined.

To achieve this independence, the AER must develop a guideline which sets not only the notional WACC elements but also a notional tax status for the entity. Such a move would set, amongst other issues, the assumed depreciation approach, remittance of fees to owners and part owners, and other assumptions used in development of the amount subject to taxation.

This approach provides for the taxation status of the notional business, and removes the ownership and taxation approaches used by each unique business.

[6] Remittance of fees for services to overseas owners is a neat way of repatriating profits without paying tax. This is a matter for the ATO, but as the AER will have to assess the amount of tax an entity will have to pay as part of the PTRM approach, it also impacts the AER"s decision making.

6.5.1 Regulatory asset base (RAB)

The RAB is based on a declared value of assets at a given time and is stated in schedule 6.2. This amount is to be adjusted by the inclusion of actual capex incurred and depreciation allowed. The RAB is adjusted by actual CPI to define its "real" value.

This approach is as used in the TNSP decision by the AEMC.

The use of the TNSP approach for DNSPs raises a fundamental concern for MEU. The decision by the AEMC to use ex ante assessments for capex was predicated on the view that most TNSP capex is "lumpy", and therefore, because there are few but large projects, TNSP capex programs can be assessed ex ante for prudency and efficiency. The MEU does not agree that this is sufficient, and has had direct experience where a TNSP has assessed a capex program which was accepted as prudent and efficient on an ex ante basis. Subsequent to the actual execution of the project, it was identified that the actual expenditure was significantly greater than the estimate on which approval was granted. In fact, based on the ex post assessment of the project an alternative approach would have been more viable (and still prudent and efficient) than incurring the actual capex.

This then raises the concern that a TNSP has an incentive to understate the expected capex for a project such that it's preferred solution will be implemented, knowing that the actual capex will be included in the RAB at the end of the period without any adjustment. The TNSP has the ability to modify for project implementation timing to ensure that it does not incur any costs. Such an ability is not in the long term interests of consumers.

In the case of a DNSP its projects are much smaller than those of a TNSP. This makes an ex ante assessment of all potential projects more difficult, as it requires assessment of a large number of small projects. This is further complicated by the preferred approaches of DNSPs to use a probabilistic approach to developing capex needs. This approach assigns a probability to each project proceeding in the period. Thus an ex ante assessment for efficiency and prudency requires a review of projects that may not even proceed.

As it is proposed that there be no ex post assessment of projects by DNSPs (following the AEMC approach for TNSPs), having a large number of small projects provided a DNSP an incentive to implement their preferred projects in such a way that they can readily cover any project over runs in their capex and by paid for them. Deferring a project into the next period is readily achieved in a probabilistic capex assessment.

The MEU believes that the ease with which a DNSP can game the capex with impunity in the absence of ex post review is a very significant risk for consumers and even exceeds by a large margin the ability of a TNSP to game the process.

Therefore, the RAB roll forward of capex must only be permitted after an ex post review of capex incurred to ensure that this was indeed prudent and efficient.

6.5.2 Return on capital (WACC)

The MEU supports the decision not to set the WACC parameters in the Rules, as was done for TNSPs by the AEMC. The AEMC did this based on an assumption that the AER should use the parameters used in the ACCC SRP guidelines, which were set some 2-3 years ago. Even then the AEMC decided that at least one parameter was wrong and changed this in favour of the TNSPs. This is an inconsistent approach by the AEMC and is another element contributing to consumer's concerns with the balance of the AEMC revenue Rules determination.

For a decade or more jurisdictional regulators have consistently used WACC parameters which are as used by the ACCC or have been adjusted to reflect the concerns pointed out by consumers.

The MEU supports that the AER should assess WACC parameters on their merits, rather than having them prescribed.

Review of rate of return parameters

(g) The MEU supports the principle that WACC parameters should be assessed on a regular basis. In practice this is done now at each reset review. The concept that a review be done each five years appears to have some merit as there is a view that the parameters do not vary greatly on a year on year basis. In fact all of the parameters vary on a daily basis, and therefore an extended period between reviews might not be in the interests of consumers or regulated business.

The MEU has three basic concerns with the proposal:-

- Setting WACC parameters creates a timing issue. Consider the AER review sets the parameters in mid 2009. In 2010 ETSA is reviewed and will have these parameters applying to them until 2015. NSW DNSPs will be reviewed in 2014, and the AER 2009 parameters will apply to them until 2019, ie 10 years after the review applied. This timing impact of the WACC review is at total odds with the reset review program and will impact each DNSP disproportionately.

- The WACC parameters (especially equity beta and market risk premium (MRP)) effectively vary on a daily basis. If the plan is to have the AER set forward looking inputs into the WACC formula, then the timing between the WACC review and their application to DNSPs, will result in the use of out of date data
- Currently MRP is set at the long term average of 6%. Independent reviews by many economists (such as Prof R R Officer) have shown that the MRP has varied over time and that in the recent 30 year period has been lower than the average. The import of this is that there will be a time when MRP must rise above the long term average. If this occurs, then a DNSP will have difficulty in sourcing funds for capex, as the regulated WACC will be low compared to the market. The only possible outcomes from this scenario is the DNSP will seek a re-opening of the decision, or supply reliability and quality will suffer.

Because of these reasons, the MEU considers that the proposal for five yearly WACC reviews is fundamentally flawed and the MEU recommends there be an AER review of all WACC parameters, including the cost of debt at each and every regulatory reset.

6.5.7 Forecast capital expenditure

As noted above, the MEU has a significant concern with capex being assessed purely on an ex ante basis. Whilst an ex ante basis must be the basis to set capex for the next period, the MEU for the reasons noted earlier, considers it essential for there to be an ex post review of capex incurred to ensure that the capex is prudent and efficient, and that the ability for the DNSP to game the regulator is constrained.

In the TNSP review, the AEMC considered that due to the lumpy nature of TNSP investments, there was a strong case for the introduction of contingent projects. These were identified as projects where there was a large investment required, but a high degree of uncertainty as to the timing for implementation. The AER is permitted to reopen a reset to include such a project if it can be demonstrated that there is a need for it to proceed during a current period.

There is no equivalent high degree of uncertainty for large "lumpy" projects in a distribution network. The MEU considers that the need for a contingent project approach for DNSPs does not arise, and therefore should be excluded as one of the bases for reopening a reset.

6.6.2 Service target performance incentive scheme

A distribution network is where most of the issues of supply are seen by consumers. Generally the supply of power from generators and delivery in the transmission system is of a high performance level that there are few times where consumers lose supply or suffer quality issues.

The MEU supports incentivising DNSPs to find better and lower cost ways to provide the services. Equally, an improvement in performance should be rewarded. A sharing of the benefit is a sound way to recognise the effort provided by the DNSP.

What is of concern is that there is an active incentive to a DNSP to use approved capex and opex for aspects where a bonus can be achieved, without dedicating funds to areas where there is an obvious need but which would not enhance a bonus.

It is the setting of the service standards against which performance is measured which creates the concern. Jurisdictions continue to have the ability to set performance standards, yet it is the AER that provides the mechanism for rewards. There is a disconnect between these two.

There is a view that in many locations in a distribution network that performance standards are acceptable, and to improve these provides little benefit to consumers. Equally there are points at which performance is poor, yet if the volume is low these locations will have little bearing on the overall averaged performance standard.

The MEU would like to see a requirement in the Rules that requires DNSPs to identify the worst served areas in the network and to have an incentive to bring these up to a similar standard available elsewhere in the network.

Part E – Regulatory proposal

The MEU would like to see that a DNSP is required to provide information during a period to the AER, to demonstrate its performance against all of the matters addressed in the reset.

The AER should have the power to establish a standard format for all information provision by a DNSP and that the DNSP must provide information in this format.

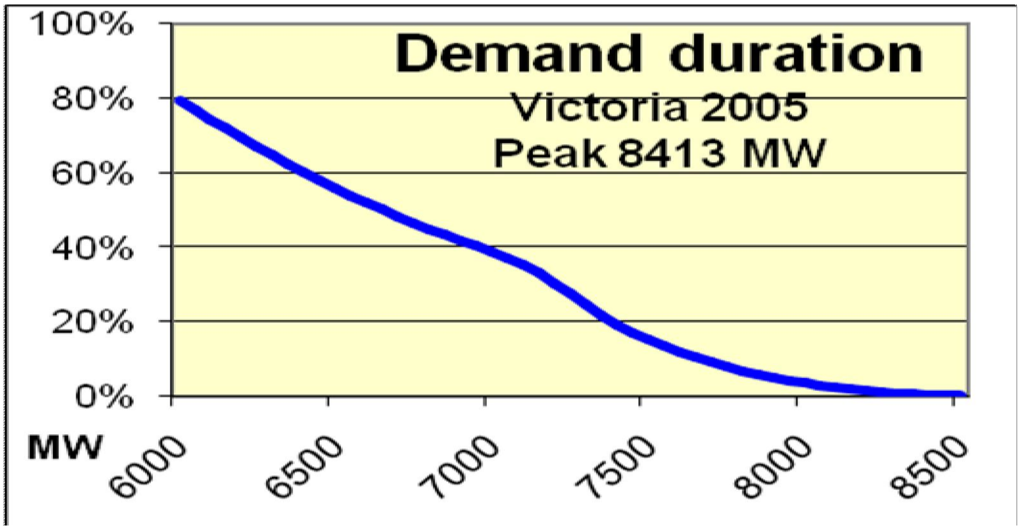
Part–G - Cost Allocation

The Rules must be explicit in that all costs allocated between services must be on a cost reflective basis. As noted above there is either no incentive on a DNSP to allocate costs properly or it has an incentive to allocate costs so that it can maximise its revenue. Neither of these options is in the interests of consumers.

Part J – Distribution Pricing Rules

In its submission to the AER relating to pricing guidelines for transmission, the MEU provided the following observations about the impact of the demand for electricity and its usage patterns (pages 11 and 12).

"In Victoria in 2005[7], the peak regional demand was some 8413 MW. In that year the lowest demand was 3780MW on Christmas Day, a Sunday. Over the year, a low of about 4000 MW was recorded a number of times.

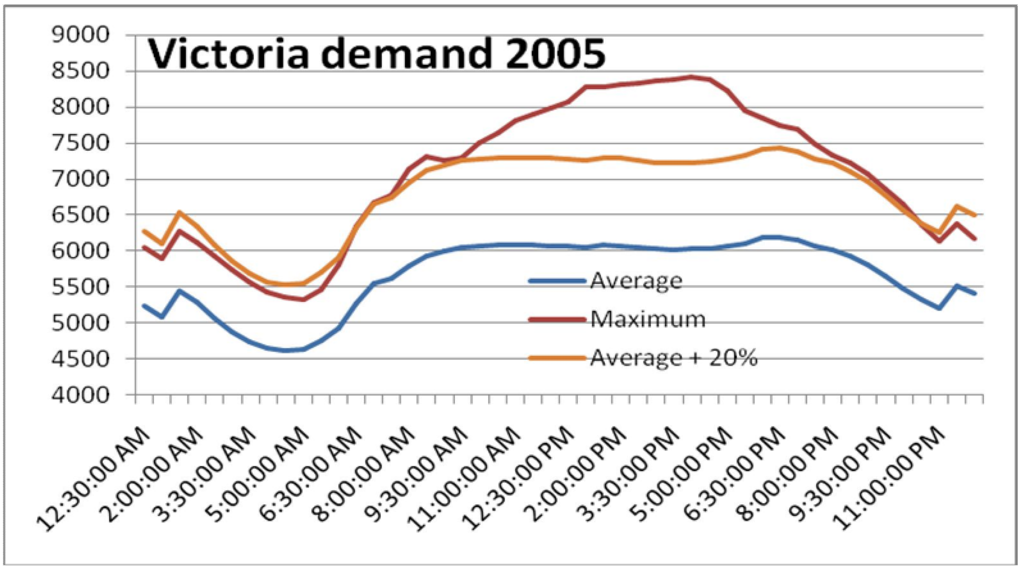


Source: NEMMCo and NEM Review

This chart implies that the Victorian network must be sized to transport a minimum 4000 MW with a peak capacity of over 8500 MW – a range of over two times.

A review of the average daily load shape of the Victorian demand for 2005 shows that, on average, the average minimum demand was some 4600 MW and there is an average peak of 6200 MW. The demand levels below the average peak demand of 6200 MW would have applied for about 70% of the time.

7 This year and region was selected as it is observed that it is typical of most regional demand variation. The demand in SA is more "peaky" than this, but Queensland is less so – NSW has a similar pattern to that of Victoria.



Data source: NEMMCo and NEM Review

> By applying an averaging technique, it is clear that for about 2/3rds of the time during the day the peak demands recorded for each half hour period of the day are within about 20% of the average demand through the year. This analysis indicates that that most users of electricity would have a normal variation in demand of 20% of the average."

There is little doubt that the costs associated with electricity transport are driven by the costs of the infrastructure – that the bulk of the revenue needed by a distribution or transmission business are capital related. The amount of capital invested is driven in turn by the need to match the peak demand of the network, and not at all by the consumption of electricity. This is clearly reflected in the charts included above.

It was because of these concerns the MEU pointed out that (pages 9 and 10) :-

> "Pricing is the allocation of the revenue streams into clearly identifiable elements so that consumers can readily see that the allocation of the permitted revenue is equitably allocated between all consumers representing the share of the cost of the provision of the transmission network. The outcome of this approach provides for all consumers to see that they each pay their equitable share of the jointly used assets. It also provides certainty that decisions made by each user (such as location, time of and frequency of use, and overall demand placed on the network) are adequately recognised by the user, and that no one user is effectively supporting less rational decisions by another user.
>
> Inappropriate pricing of services leads to inefficient outcomes. A user that is convinced that it is paying too much for the service will take a number of actions to reduce its costs, perhaps leading to nationally inefficient outcomes. The user that is not paying its fair share for the service undervalues it and makes inappropriate use of the facility. Over

> allocation of transmission costs can lead to companies deciding to relocate overseas or close down, causing remaining users to provide that contribution from the business ceasing its operations. Equally, under allocation of costs results in the proliferation of occasional users who do not recognise that impact of the decisions they are making."

It is with these observations and concerns in mind that the MEU makes its following comments.

<u>6.18.3 Pricing Proposals</u>

The MEU is concerned that DNSPs' pricing proposals may enable 'gaming' and disadvantage some customer classes unless there are specific AER guidelines that prevent this. The Rules should specify this. The AER guidelines should also contain guidance on the signals for cost reflectivity as the bulk of the costs associated with a distribution network are related to capital needed to match demand than to matching consumption. This means that prices are more driven by demand and not consumption.

The pricing should also provide signals to consumers so that they can fully appreciate the impact their decisions make to the construction of the network. In this regard, we refer to the submission MEU made to the AER regarding its pricing guidelines for transmission (and the origin of the quotations made above) which provides much more detail and explanation of the MEU views in regard to pricing. This submission is posted on the AER website[8] and we note that the drivers of investment in distribution are much as those in transmission making the commentary and reasons behind pricing equally applicable to both.

The MEU notes, in particular, that prices based on the Baumol Willig rule (as detailed in 6.18.5(a)) would produce a very wide range, thereby enabling cross-subsidisation between customer classes, which is likely to be accentuated as side constraints are being proposed (for the ACT/NSW transitional arrangements) in the Rules.

As noted in section 2 above, DNSPs have used the wide discretion available to them by the application of the Baumol Willig range, to maximise revenue, which is effectively a result of financial engineering than of providing a service.

Accordingly, Clause 6.18.3 should contain a reference to the requirement for the AER to develop guidelines that seek to ensure:

- **cost reflectivity**

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[8] www.aer.gov.au/content/item.phtml?itemId=711271&nodeId=2bceb554d62779f8325705bfaa8df49d&fn=Major%20Energy%20Users%20Inc%20(May%202007).pdf

- **recognition of the impacts made by the consumers on the network**
- **and which provide strong signals to consumers of how their decisions will impact on the network, and its capex requirements.**

6.18.5 Pricing Principles

(a) The MEU is concerned that the current draft Rule will result in tariffs that are not cost reflective nor efficient for some customer classes because of the wide range proposed.

The AER should be required to carryout an indepth assessment of the pricing proposed by a DNSP to ensure that the pricing delivers the expected revenue (and no more other than that earned by demand growth) and provides signals from both the DNSP and TNSP to consumers to reflect their usage pattern.

6.18.6 Side constraints on tariffs for standard control services

This clause, in particular, can result in providing no pricing signals to certain customer classes, nor provide cost-reflectivity. The lower the permitted percentage increase between regulatory periods, the more distortive the tariff becomes. This normally would result in cross-subsidisation from large users to small users.

The permissible percentage of CPI-X plus 2% (clause 6.18.6 (b)) is far too small and readily promotes cross-subsidisation between customer classes. It also defeats the moves to cost reflectivity in tariffs thereby fudging signals for demand-management.

5. <u>Savings and Transitional Rules</u>

<u>Form of Regulation, Price Control method and Form of Price Control</u>

The MEU **supports**, in the case of ACT and NSW, the form of regulation that ICRC and IPART applied to distribution services in their last determinations. In addition, it is **strongly agreed** that the price control setting method will be the building block method **based on a post tax revenue model** (rather than a pre tax model previously used by ICRC and IPART).

The MEU **supports** the use of an average price cap for Actew AGL and a weighted average price cap for the 3 NSW distributors.

The above arrangements provide certainty for both regulated businesses and customers. It may, however, be worth considering some transitional arrangements for new pricing proposals to contain both the current **and** new classifications (at least in a few major areas).

<u>The NSW and ACT reviews</u>

At the recent public forum to present the proposed Rules, the MEU representative at the forum made the comment that the NSW government proposal for the transitional Rules for the three distribution businesses and ActewAGL were biased so that every opportunity had been taken to maximise the revenue for the DNSPs before the final Rules were introduced. A careful review of the detail has not changed this view in the slightest.

It is clear that where possible the NSW government (as owner of the three NSW distribution businesses) has used the best of the old IPART and ICRC Rules with the best of the new exposure draft Rules to maximise the revenue for its businesses. The MEU is of the view that either one or the other approach would be a better and more transparent approach for the transition.

1. <u>Opening Regulatory Asset Base</u>

We note that the transitional arrangements state that:-

> "*The opening regulatory asset base will need to include capital expenditure between 1 July 2004 and 30 June 2009. The exposure draft rules roll-in the actual capital expenditure, but the transitionals should only roll-in to the RAB the capital expenditure which would have been eligible under the jurisdictional regulators' criteria.*"

The MEU would prefer to have "actual capital expenditure" rolled-in. However, whichever roll-in method is used, **it must be applied only after an ex-post audit of past expenditure is undertaken by the AER.** As pointed out earlier, DNSPs networks are quite different to TNSPs – there are substantially more projects involved and the dollar amounts are very substantial, so that the opportunities for 'gaming' are considerably enhanced. Automatic roll-in of actual capital expenditure or eligible expenditure under jurisdictional regulators' criteria tips the balance of interests decisively against the consumer. We have shown, earlier, the extent of 'gaming' by DNSPs in Victoria.

We note also the additional concession given to DNSPs viz:-

> "*Acknowledging that the jurisdictional regulators' past determination would not bind future determinations, the AER will need to make any other adjustments to the RAB at the next determination that the jurisdictional regulators had envisaged in their determinations, policies or guidelines" (*Page 44).

It is imperative, in the interests of consumers that, at the very least, the Rules require the AER to conduct an ex-post audit of past capex and opex.

2. Weighted Average cost of Capital

The MEU does **not** support any move for the AER reviews for distribution to adopt the AEMC transmission WACC parameters, especially for the NSW review prior to the AER detailed review of WACC parameters.

The key AEMC WACC parameters are at the high end of the permissible ranges and are completely inappropriate, let alone fair to consumers. As we have pointed out, the AEMC decision was immediately welcomed by equity market investors, who clearly assessed that the AEMC had made a decisive move in favouring TNSPs. (see appendix A).

3. Incentive Schemes

It is generally considered that IPART's incentive schemes have never been supported by major energy users as the penalty for not meeting performance standards is set too low. Moreover, IPART's D-factor scheme to recognize demand management costs incurred by DNSP's opens up a vast avenue for 'double dipping' by DNSPs.

If the transitional arrangements are to adopt the S-factor and D-factor schemes, there must be a requirement for the AER to conduct a careful audit of such schemes, so as to prevent DNSPs from unwarranted profiteering.

4. Guidelines for ACT/NSW resets

The AER has little or no exposure to distribution pricing to date and probably has deficient skills in this area. It is imperative that the AER consults closely with energy consumers who have considerable history of experience with DNSP's pricing and service performance. Key areas are pricing methodologies, cost allocations, service performance and connection agreements. The Rules should be clear on this need for close consultation especially driving the transitional arrangements phase.

Appendix A

MAJOR ENERGY USERS INC.

THE VOICE OF ENERGY CONSUMERS

The Securities Market's Analysis of the AEMC's Determination on Electricity Transmission Revenue

By

The Major Energy Users Inc

January 2007

This monograph has been prepared for Major Energy Users Inc by Headberry Partners and Bob Lim & Co.

The conclusions reached are those of MEU and the authors.

Before market data on Utilities was available

Prior to 2001, there was no suitable ASX index available to Australian energy regulators to assist in establishing an equity beta for the class of energy transport **Utilities** from which could be calculated a regulated revenue stream (arising from the economic regulation of monopoly network businesses). Because there was no such specific asset class regulators had to interpolate an appropriate equity beta from indices published for other asset classes.

For example, in 2002[9] the ACCC used the following chart of equity betas prepared by the AGSM in order to develop a specific **Utilities** equity beta.

Table 2.2 Average equity beta by industry listed on the ASX

Industry	Average Equity Beta
Property Trusts	0.366
Alcohol and Tobacco	0.420
Food and Household	0.424
Transport	0.463
Diversified Industrials	0.719
Engineering	0.756
Building Materials	0.857
Paper and Packaging	0.953
Developers and Contractors	0.954
Banks and Finance	0.967
Infrastructure and Utilities	0.983
Tourism and Leisure	1.084
Chemicals	1.128
Investment and Financial Services	1.131
Retail	1.269
Mining and Energy	1.305
Insurance	1.394
Other Metals	1.502
Miscellaneous Industrials	1.568
Diversified resources	1.571
Gold	1.678
HealthCare and Bio-Technology	1.899
Media	2.076
Telecommunications	2.772

Source: Australian Graduate School of Management centre for research in finance; risk measurement service

[9] As used in the draft decision for ElectraNet in 2002

Based on the above listing, the ACCC determined that an equity beta of **unity** was appropriate as this was about the same as the equity beta for the index for **Infrastructure and Utilities**. The ACCC has not changed this value for equity beta since that time. Almost all jurisdictional regulators have used an equity beta less then 1.0 in recent decisions, using equity betas as low as 0.8 for electricity utilities (eg ESCoSA on ETSA Utilities although this was revised to 0.9 on appeal) and 0.75 for water Utilities (eg ESCoV).

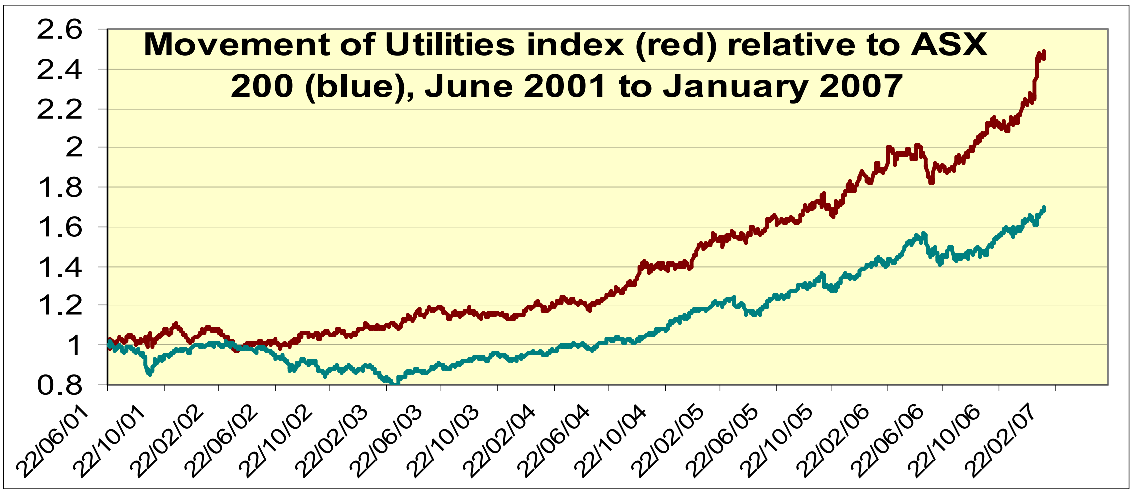
The clear import was that an equity beta of 1.0 was seen by most regulators as being too high.

Market data is now available for Utilities

Since June 2001, the ASX (with Standard and Poors) has published details of an asset class (and an index) purely for **Utilities** coded XUJ. This index comprises the listed gas utilities such as APT, Envestra, Alinta and the listed electricity utilities such as Spark and SP Ausnet. These asset owning companies cover electricity and gas Utilities in Victoria, South Australia, Western Australia, Northern Territory, Queensland and NSW. The movement of this index relative to the ASX 200 is best shown using the starting point of both indices as unity.

Analysis of the financial performance of **Utilities** compared to the market average shows that **Utilities** have significantly out performed the market (as typified by the ASX 200). In fact, the **Utilities** index has increased at a rate 50% more than the rate of increase of the ASX 200 over a period of nearly six years of its existence. Based on five year trend lines the performance of the **Utilities** index implies a market risk premium (MRP) of 11.26% using the equity beta of 1.0 as used by ESCoV, whereas the ASX 200 shows an MRP of 4.5% at an equity beta of 1.36 derived from an asset beta of 1.0 and gearing of 36%[10].

[10] See appendix 1 showing gearing of the “All Ords” as D/E = 36%



Source: CommSec

The ASX200 was used as the surrogate index for the average of the market performance as it comprises the companies comprising the bulk of the ASX's market capitalisation.

The Major Energy Users Inc. (MEU) has previously provided information to the AEMC (during its review of electricity transmission revenue and pricing) that the outworkings of the performance of the **Utilities** index implied a market risk premium (based on an equity beta of 1.0 used by AER and ESCoV) of nearly twice that used by regulators of 6%.

The impact on equity beta

Analysis of the risk and stability performance of the **Utilities** index by the independent assessor CommSec implies an asset beta of 0.3 is typical for this class of assets as measured over the past 5-6 years. This compares well with the observed asset beta for similar utilities operating in other countries, such as the US. The following table 9.5 provided by the ESCoV in its recent decision on electricity distribution companies demonstrates this clearly.

Table 9.5: Lally (2005) asset beta estimates, with equity beta estimates

Source	Data Period	Number of firms in sample	Electricity Utilities Asset Beta	Electricity Utilities Equity Beta	Gas Asset Beta	Gas Equity Beta	Overall Asset Beta	Overall Equity Beta
Value Line	1999 – 2003	83	0.35	0.88	0.17	0.43	0.29	0.73
Value Line	1994 – 1998	147	0.26	0.65	0.26	0.65	0.26	0.65
Bloomberg	2002 – 2003	93	0.27	0.68	0.20	0.50	0.25	0.63
Alexander	1990 – 1994	35	0.33	0.83	0.22	0.55	0.27	0.68
Ibbotson	1999 – 2003	50	0.12	0.30	0.06	0.15	0.11	0.28
Ibbotson	1993 – 1997	108	0.32	0.80	0.33	0.83	0.32	0.80
S&P	1999 – 2003	80	0.18	0.45	0.19	0.48	0.19	0.48
S&P	1994 – 1998	73	0.19	0.48	0.32	0.80	0.26	0.65
S&P	1989 – 1993	65	0.34	0.85	0.29	0.73	0.32	0.80
Median			0.27	0.68	0.22	0.55	0.26	0.65

Source: Lally (2005, p. 14). The Commission has generated equity betas consistent with 60 per cent gearing.

A continuing view has been that the lower levels of historic equity betas, such as those available from the US market were a result of a “tech boom and bust” in the equities markets resulting from the impact of technology stocks of the late 1990s.

Whilst accepting that this “tech boom and bust” might have impacted assessment of equity betas in the early part of this century, nearly six years of recent market data in Australia and overseas supports that the impact of this “tech boom and bust” might well have been grossly overstated (or at least been quite short lived) as equity betas derived after many years since the “boom and bust” period still maintain the similar levels (see appendix 1) as they were during the period of the “tech boom and bust”.

CommSec has also noted that the current (30 Jan 07) gearing of the **Utilities** sector is 102% (Debt/Equity) which when used with the current (30 Jan 07) asset beta of 0.39, results in an equity beta of 0.79. Previous values of asset beta developed by CommSec were significantly lower than the current 0.39, implying that the current equity beta of 0.79 is on the high side of the average. Attached as appendix 1 is a summary of the ASX sector analysis provided by CommSec on three separate dates, all some 6 months apart.

Much of this information was provided to the AEMC as part of its review of transmission revenue, but it elected not to investigate this issue at all. Without undertaking any of its own assessment, the AEMC determined in the transmission revenue Rules that transmission companies should be granted a market risk premium of 6% and an equity beta of 1.0, and locked these into the Electricity Rules, preventing any changes being made, although it has required the AER to undertake another review of the CAPM inputs by 2008. **In the meantime all AER reviews must use these AEMC prescribed inputs.**

The AEMC stated that by fixing these inputs in the Rules it created more certainty for transmission companies, and therefore it was likely that increased investment would result. Certainly this would result in more profits for the electricity transmission businesses!

But there was even more from the AEMC

The AEMC also determined that the AER should be more influenced by the claims of the transmission companies for opex and capex to be included in the revenue application and determined that the AER role in oversighting past capex incurred should be prudent and efficient should be minimal.. Again, the AEMC concluded that this would provide an incentive for the transmission companies to invest – it certainly enables the businesses to “gold-plate” investments and make life easier for the businesses!

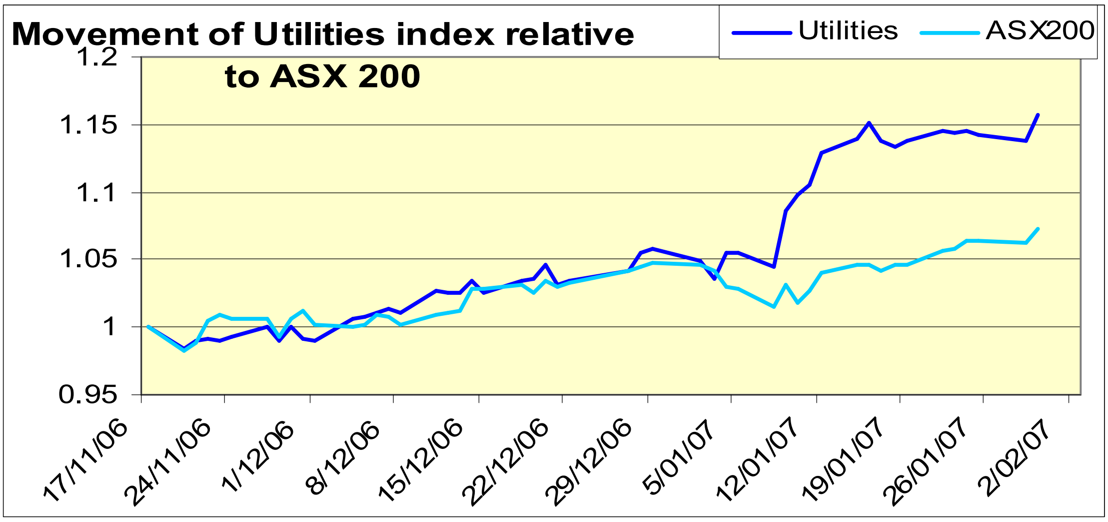
The MEU had pointed out to the AEMC that there had already been significant investment in transmission assets and that transmission companies were in fact not constrained in investing by the regulatory approach, but more by their own inability to manage the investment programs already approved. The MEU requested the AEMC to identify where investment had been constrained, but the AEMC did not undertake any research which might have supported their view.

The MEU had also advised the AEMC that its proposed Rule changes would increase the profitability of transmission companies and not necessarily result in expanding investment. The AEMC ignored this contention.

The AEMC released its final determination and rules on electricity transmission revenue on 17 November 2006 and on transmission pricing on December 21, 2006. Since then, the **Utilities** index has risen so significantly compared to the market average that the release of the AEMC Rule changes and this increase cannot be dissociated from each other.

The following chart shows that the decisions of the AEMC have contributed to a significant increase in the market value of Utilities. Allowing for the time for market analysts to assess the outcome of the AEMC decisions, the chart clearly shows that the market recognises that Santa (in the guise of the AEMC) has delivered an excellent present to Utilities and their investors.

Investors can clearly see that the utilities will be even more profitable businesses (relative to risk) than before. The chart shows a massive outperfomance of the Utilities Sector relative to the ASX 200.



Source: CommSec

The chart relates both the Utilities index and the ASX 200 back to unity at 17 November, the day the AEMC released its decision on transmission revenue. On 17 December the AEMC released its decision on transmission pricing. The fact that after an early surge in January as the AEMC decisions were analysed, the spike flattened and the two indices resumed similar but parallel tracking as before.

Whilst the AEMC can state that their decision only relates to electricity transmission, there can be no presumption that this decision will not flow (in whole or part) to all energy transport services of gas transmission and gas and electricity distribution. The earlier efforts by the jurisdictional regulators (ICRC, IPART, ESCoSA and QCA) in reducing equity beta for regulated energy transport businesses and to control any excesses of the regulated energy businesses have come to nought.

It is quite clear that the market has seen the AEMC decision as a Christmas present of the first order.

Appendix 1 Data sourced from Commonwealth Securities Web site

	ASX code of typical company in sector	Beta			Sector div yield			sector gearing D/E % 30 Jan 07
		27-Feb-06	23-Aug-06	30-Jan-07	27-Feb-06	23-Aug-06	30-Jan-07	
All ords		**1.08**	**1.04**	**1.02**	**4.3**	**4.3**	**3**	**36**
Consumer discretionary								
Automobiles and components	BOS	1.02	0.86	1.45	6.2	6.2	0.8	
consumer durables and apparel	GUD	1.75	1.39	1.42	5.3	5.2	5.3	44
consumer services	TAH	0.93	1.19	0.96	4.3	3.9	3.3	38
Media	PBL	1.51	1.39	1.03	4.5	4.4	3.9	21
Retailing	HVN	1.18	0.99	0.98	4.6	4.7	3.2	32
Consumer staples								
Food and drug retailing	WOW	0.62	0.64	0.64	3.8	3	3	75
Food beverage and tobacco	LNN	0.58	0.51	0.6	4.3	3.9	3.1	46
Energy		**0.96**	**1.04**	**1.21**	**3**	**2.8**	**2.8**	
Energy Equipment and services	HZN							
Oil and Gas	ORG							
Financials ex property								
Banks	CBA	0.86	0.68	0.82	4.3	4.1	4.4	
Diversified financials - resources	BNB	1.19	1.16	1.17	3.5	3.7	3.6	
Diversified financials - holdings	SOL	1.19	1.16		3.5	3.7		
Insurance	AMP	1.58	1.54	1.44	4.2	4	3	
Property Trusts		**1**	**1.04**	**1**	**6.9**	**6.9**	**3.8**	
Investment trusts	WDC							
management and development	CEQ							
Health Care								
Equipment and services	SHL	1.19	1.09	1.01	2.8	3	2.7	7.2
Pharma & Biotech	SIP	1.81	1.52	1.01	2.3	2.9	2.7	7.2

Data sourced from Commonwealth Securities Web site								
	ASX code of typical company in sector	Beta			Sector div yield			sector gearing D/E % 30 Jan 07
		27-Feb-06	23-Aug-06	30-Jan-07	27-Feb-06	23-Aug-06	30-Jan-07	
Industrials								
Capital goods	COA	1.11	1.12	1.04	4	4.1	3.6	34
Commercial services and supplies	BXB	1.11	1.19	1.27	4	3.9	3.4	28
Transportation	ADZ	0.9	0.99	0.96	4.7	4.9	3.4	40
Info Tech								
Software and services	CPU	1.82	1.61	1.34	4.6	4.6	3.4	54
hardware and equipment	KYC	1.15	1.02	0.89	4.4	3.9	2.7	0.7
Semiconductors	LGD	1.15	1.02	0.89	0	0	0	58
Materials		**1.39**	**1.15**	**1.22**	**3.1**	**3.2**	**3.1**	
Chemicals	ORI							
Construction materials	ABC							
Containers and packaging	AMC							
Aluminium	AWC							
Diversified metals and mining	BHP							
Gold	NCM							
Precious metals and minerals	ERA							
Steel	BSL							
paper and forest products	PPX							
Telecomms		**0.44**	**0.29**	**0.37**	**5.7**	**6.2**	**3**	**15**
Diversified	ENG							
Wireless	HTA							
Utilities		**0.31**	**0.23**	**0.37**	**5.2**	**5**	**4.1**	**102**
Electric	HDF							
gas	ALN							
Multi	SPN							
Unclassified	BQF	**1**	**0.98**		**6.9**	**6.9**		