AER Preliminary Position paper

DMIS, Control Mechanism for ACS and Materiality in Pass through for NSW/ACT businesses

January 2008

1 Introduction

EnergyAustralia is pleased to respond to the AER Preliminary Positions paper on matters it is required to address for NSW/ACT businesses under the new National Framework. We note that many of the suggestions we made in response to the earlier Preliminary Positions document were adopted and expect that this second round of consultation should refine the proposals.

2 Demand management incentive scheme

2.1 Approach to D-Factor

EnergyAustralia supports the AER's decision to apply a similar incentive mechanism to that applying in the current regulatory control period (the D-factor). As noted in our response to the AER issues paper, the existing D-factor mechanism:

- effectively compensates DNSPs for a limited number of investments for the tariff revenue loss;
- neutralises the risk driven disincentives; and
- provides a positive incentive by allowing recovery of the project cost (usually an opex cost rather than capex) and any associated time value of money due to the two year lag.

The D-factor as administered by IPART has been an effective mechanism for promoting the wider use of this category of demand management activity.

However, as we also raised in our previous response, D-Factor incentives are limited to a specific category of proven demand management investment. Existing incentives for non-tariff demand management only apply when a demand-side option is identified as being an efficient alternative to a supply-side (network) solution to address specific network capacity constraints. These types of projects are location specific and linked explicitly to a supply side project that is capable of being deferred or potentially removed from the capital program.

2.2 Approach to Learn by Doing

EnergyAustralia continues to support the expansion of the current D-factor to include a "learn-by-doing" style approach to ensure innovative approaches to capital deferral which are at a conceptual stage can be investigated, developed and, if successful, implemented when future opportunities arise. This approach would supplement the existing D-Factor.

EnergyAustralia believes that customers would be willing to pay to ensure innovations lead to more energy and cost efficient solutions in the future, particularly when the incremental impact on tariffs is negligible.

In short, EnergyAustralia fully supports the AER's analysis and its proposal to establish a learn by doing fund. However we believe the expenditure limits for this activity proposed by the AER fall well short of those necessary to foster any noticeable expansion in the range of practical and reliable DM options available to DNSPs.

In its preliminary positions paper, the AER:

- Acknowledges it is aware of the modest results achieved to date from the operation of the D-factor alone[1];
- Suggests a small allowance to further encourage DNSPs to undertake demand management, such as a learning-by-doing fund, may be in the long term interests of energy users[2];
- Notes there is currently insufficient information on customer willingness to pay for demand management, and
- Considers a modest learning-by-doing fund will enable DNSPs conduct demand management trials of a more experimental nature which will provide greater information on customer willingness to pay, without resulting in significant customer price increases.[3]

We fully support this analysis, but cannot reconcile it with the final recommendations. The AER proposes that the fund will be capped at amounts dependent upon the DNSP's size, varying from $1 million in total for EnergyAustralia to $100,000 for ActewAGL, during the 2009-2014 regulatory period.

For EnergyAustralia, in 2006/07 this average of $200,000 per annum for learn by doing equates to:

- 0.0035 % of the RAB;
- 0.03% of the capex spend; and
- 0.018 % of revenue.

These percentages will be lower still at the time the scheme is implemented.

EnergyAustralia believes such a small amount will fail to deliver any noticeable change in the future expansion of demand management activities. EnergyAustralia's feedback from stakeholders supports a view that customers would be willing to contribute at a significantly higher level to achieve positive outcomes in demand management and a substantially higher cap is warranted.

2.2.1 Will it further encourage DNSPs to undertake demand management

At the proposed thresholds, the AER's approach will not provide adequate funding for any significant demand management investment.

Three examples of projects with a demand management focus which EnergyAustralia undertook during the current determination are as follows:

1. The Strategic Pricing Study is currently underway and was intended to test consumer acceptance of and response to dynamic price signals, seasonal Time of Use prices and in home displays. The study involved a statistically robust sample of 1,300 customers and has so far cost in excess of $1.6 million.
2. The Advanced Metering Infrastructure pilot program was a technology trial which involved the installation of 7,000 meters with two way communications, using a range of different manufacturers and communications technologies. To date, this investigation has cost $6.2 million and is planned to be extended into the next regulatory period.

   The two projects above were not foreseen or foreseeable at the time of the submission to the 2004 determination, but arose during the current period with the development of more affordable advanced metering technology. Had they been foreseen, the costs would have formed part of EnergyAustralia's regulatory proposal. This was the case with the roll out of

1 Preliminary positions paper p16
2 Preliminary positions paper p20
3 Preliminary positions paper p22

interval meters and Time of Use tariffs to customers with consumption between 15 and 160 MWh, where IPART permitted funding of $46 million as part of its determination[4].

3. A demand curtailment project was undertaken to examine the feasibility of reducing demand in the Sydney CBD, by employing more sophisticated management of air conditioning and services in office buildings. The project involved two stages and included commercial engagement with a third party provider and consultant reviews of the technical feasibility. This project cost in excess of $1.0 million and confirmed that this form of demand management would be very expensive in relative terms and of insufficient in impact to permit a year's deferral of augmentation works.

   This project was initiated before IPART's decision concerning the form of the D-Factor had been finalised, in anticipation that an allowance for such learn by doing projects would be provided. This proved not to be the case.

4. The Demand Management and Planning Project, jointly undertaken by EnergyAustralia, TransGrid and the NSW Dept of Planning is a five year project designed to provide robust information about the potential quantity and cost of demand management options in the Sydney Inner Metropolitan Area. Due for completion in early 2008, the project has reviewed demand reduction opportunities at approximately 800 high energy using sites and is conducting a series of demonstration projects designed to validate the cost and performance of these opportunities. The project has taken over five years and cost $10m.

5. EnergyAustralia is developing an Energy Efficiency Centre as a focal point for promoting existing and future demand management initiatives such as Time of Use pricing, smart metering and sustainability initiatives. It will also be used to promote staff, industry and stakeholder awareness and training on demand management, energy efficiency, greenhouse gas abatement and sustainability and is an important element of corporate social responsibility. This project is now well advanced, being scheduled for completion in the second quarter of 2008.

   The cost to set up the centre will be in excess of $3 million and its annual operating costs in the vicinity of $0.3-0.4 million. Those operating costs will be included in EnergyAustralia's regulatory submission.

The AER will be aware that these projects have provided valuable insights into the debate on investment in new technologies. We would have considered that these are precisely the types of projects that the AER should be encouraging, rather than restricting.

It is apparent that the AER's proposed threshold would be inadequate to fund even a single project of any reasonable scale in the next determination period. In the case of ActewAGL, it is questionable whether the allowance from the fund would be sufficient to cover the costs of complying with the scheme.

As a general principle, those costs that are reasonably foreseen, including demand management related activities, should form part of the DNSP's regulatory proposal. As an example, this is very likely to be the case in 2008 with the preparations EnergyAustralia needs to make for the roll out of AMI. The D-factor should be employed where those activities that cannot be foreseen, as in the case of individual projects or programs where the detailed analysis has not been completed, or where new technology emerges.

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4 NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Report - Other Paper No 23, June 2004, Independent Pricing and Regulatory Tribunal of NSW, p37

2.2.2 Impact on pricing and willingness to pay

For EnergyAustralia, the proposed learn by doing funding of $200,000 per annum equates to 0.0007 ¢/kWh, or 4-5 cents per year for the average domestic customer. From a customer impact perspective, a multiple of 50 to 100 times the allowance proposed by the AER would be barely noticeable, at about $1 in an average quarterly retail bill of over $200. In any case, such expenditure is likely to enjoy a significant level of customer acceptance and support, particularly if it is aimed at developing technologies that will see a reduction in the overall bill at a future point in time.

2.2.3 Limitations on the use of the fund

EnergyAustralia notes that applications under the fund are proposed to be limited:

- to programs which are innovative; and
- target broad based demand reductions across the DNSPs' networks.

Leaving aside the issue of whether any worthwhile projects of this nature would fall under the limits imposed by the AER, these criteria misunderstand the fundamental requirements and would limit the value of the initiative.

There are two categories of demand management activity that are not catered for under the current D-Factor that should be considered under this alternative mechanism. One is broad based initiatives, the other is innovation in location specific demand management techniques.

EnergyAustralia suggests the application of funds be limited to projects that are either:

- innovative, have the potential, if successful, to be repeated as commercially efficient projects in other locations or sectors, but where related capital deferrals cannot be specifically identified; or
- intended to reduce peak demand on the network system, but most appropriately implemented in a broad based framework and therefore not related to changes in specific investment needs.

The former category will lead to an expansion of the range of proven and commercially prudent demand management approaches available for deployment by DNSPs. The latter will enable the implementation of projects that will result in more diffuse reductions and savings that cannot be specifically identified as generally required under the current D-Factor.

2.3 Suggested EnergyAustralia approach

EnergyAustralia requests that the AER further consider the approach we proposed in response to the preliminary positions paper, where the existing D-factor mechanism can be readily expanded to include the reasonable costs of innovation and development (learn by doing) and broad based demand management programs. This approach would maximise incentives for businesses to undertake non-network investments while minimising administrative costs.

The level of funding must be considered in the context of the level of investment DNSPs are expected to undertake in the next regulatory control period and the customer impact.

Under this approach, the D-factor allowance would include costs and related revenue forgone for both development and innovation and broad based demand management projects. Total costs claimable for the combination of these two would be subject to a predetermined annual cap (somewhere in the order of 1% of revenues). Like the existing D-factor regime, this incentive scheme would need to continue into the next regulatory control period.

The determination would identify the criteria for inclusion of projects under this cap, but in our view should include:

- Demand reduction projects and programs in specific areas that could be used in future to defer or avoid growth related capex, but where the current levels of experience and confidence in out-turn impact or costs are insufficient to justify prudent business investment; and
- Broad based demand management programs that will result in a clear reduction in demand but cannot be allocated to a specific project deferral. Costs would be limited to a specific $/kVA value that represents an average value of demand reduction.
- Projects that are primarily for the purposes of aiding demand management in the longer term, but could not readily be seen as providing immediate demand reductions, whether local or global. Such projects are primarily information gathering in nature, to support demand reduction projects under the two points above in the future.

If a project met these criteria, and also fell under the cap, a claim under the D-factor could be made for costs, revenue foregone and the time value of money.

There would be many advantages to this expansion of the existing D-Factor mechanism:

- The cap would ensure that the impact on customer bills is limited to a very small amount. Bills are only impacted upon application for D-Factor payments. The AER may consider a higher value of cap in early years of the regulatory control period. This would boost the incentive to undertake innovation and develop projects early and give earlier signals for projects that could deliver cost effective DM options under the "normal" D-Factor;
- A $/kVA limit on broad based programs would ensure that longer term reductions in capex will exceed costs (noting the existing D-factor does not consider the longer term flow-on benefits of demand reductions over time);
- The introduction of a cap and inclusion in the existing D-Factor removes the need for up-front initial approval and funding. This means that customers only bear the costs of the actual investment. Administrative costs of justifying and approving projects ex-ante of the investment under a funding option and reconciling these costs to the underlying incentive regime for opex and capex make a modification to the existing D-Factor a more attractive option; and
- It is a true incentive arrangement based on a "use it or lose it" approach. In the event that sufficient projects are not identified and implemented by the DNSP, customers would face no additional costs. This may be particularly beneficial for smaller networks such as ActewAGL where opportunities for innovative development programs are more limited.

2.3.1 Effective limits arising from EnergyAustralia approach

The 2006/07 revenue for EnergyAustralia is approximately $1.05 billion, so a cap of 1% of this would represent about $10 million per annum. As the level of system capital expenditure in the same year was $700 million, the cap would correspond to 1.4% of capex, which would still represent a relatively small portion of the cost of augmenting the network.

The amount proposed is equivalent to the current Regulatory Test threshold and significantly smaller than many of the individual projects, such as zone substations, which form part of the capex program.

2.4 Other issues

2.4.1 Clarification of Rule Requirements

EnergyAustralia would like to take the opportunity to clarify several statements by the AER regardin g the rule requirements. At section 2.5.2 the AER seeks to set out the effect of clause 6.5.7 of the Rules.

EnergyAustralia appreciates that the AER was not establishing its legal interpretation of the Rules as part of these guidelines and is seeking to explain its position as simply as possible. Nevertheless, in the context of a new framework, it is important to ensure that statements regarding rule requirement s are as accurate as possible to avoid misinterpretation by stakeholders.

As an example, the AER states that clause 6.5.7(e)(10) requires "DNSPs to demonstrate to the AER that in making capital expenditure forecasts they have had specific regard to demand management alternatives to capital expansion for each capital expansions project.". Clause 6 .5.7(e)(10) does not impose an obligation upon DNSPs to demonstrate that it has had specific regard to demand management alternatives, this obligation is imposed elsewhere in the Rules and in the case of NSW DNSP through DNSP licence conditions. Clause 6.57(e)(10) imposes an obligation upon the AER to consider the extent to which a DNSP has considered such alternatives. In response to this a prudent DNSP will ensue that it puts forward the details of such considerations as part of its regulatory proposal.

Similarly, in the same paragraph the AER states "The Transitional Rules state that if the AER is not satisfied with the DNSP's forecast expenditure, the AER must not accept the DNSP's forecast capital expenditure.; This is an over simplification of the AER's decision making obligations. It is not simply a matter of the AER not being satisfied, it is a matter of the AER determining whether it is satisfied that the forecast capex put forward by the DNSP reasonably reflects the capital expenditure criteria set out in 6.5.7(c) taking into a count a range of matters, one of which is 6.5.7(e)(10).

2.4.2 Interaction with other incentive mechanisms

We reiterate that any EBSS intended to incentivise reductions in operating costs must exclude spending on demand management, to avoid these incentive schemes acting in opposition to one another. If these costs are subject to disclosure and review under a D -factor submission process, they will be clearly identified and their exclusion relatively straightforward.

2.4.3 Costs that will be incorporated into the capital and operating expenditure programs as efficient costs under 6.5.6 and 6.5.7

The issues paper notes that the mechanism must look at incentives for DNSPs to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way. Consequently, the discussion above relates specifically to the incentivisation of DNSPs to develop and undertake demand management activities.

It is now widely recognised that network businesses such as EnergyAustralia need to invest more broadly in research and development as standard practice across their businesses. This is particularly the case in the current climate where businesses are seeing new and innovative ways to response to issues such as aging assets, increasing customer needs and climate change. The education of customers in the safe and efficient use of the product EnergyAustralia delivers is also recognised as an integral part of carrying on such a business.

EnergyAustralia believes that the operating expenses it sets aside for consumer education, and network research and development purposes represent efficient costs for a benchmark DNSP. This would mirror how non-regulated businesses in capital intensive industries cater for such expenditures.

It is important to recognise that these activities include a much wider range of matters than the focus on demand management in the discussion above.

The current D-factor does not, and should not, cater for investments in education or research into network and energy issues more generally. These costs should be considered a standard part of DNSPs' operations. EnergyAustralia will include these costs as part of its normal operating and capital expenditure forecast within its regulatory proposal.

3 Control Mechanisms for Alternative Control Services

3.1 AER's preferred form of control

EnergyAustralia supports the AER's approach to maintaining consistency with the current control mechanism, particularly given that our obligations to submit a regulatory proposal are a mere four months away.

We also support the approach to move toward a price path approach, although we would argue that this should also maintain consistency with the current arrangements, ie:

- a control on the total revenue the DNSP can earn for public lighting infrastructure in each year of the regulatory control period;
- a further control on the movement in revenues earned from a customer (such as councils);

Again, we would stress that an alternative form of control would be difficult to establish in a reasonable time.

3.2 Implementation for public lighting under the Rules framework

We believe that the AER has struck an appropriate balance between general guidance in the approach to regulation for public lighting and the flexibility offered in the Rules for control mechanisms for alternative control services. We support the approach proposed by the AER in Section 3.6.2.

EnergyAustralia appreciates that the AER is responding to the requirements of the Rules regarding the application of a control mechanism to the construction and maintenance of public lighting. We also note that the Rules have been prepared on the assumption that the construction and maintenance of public lighting is a "distribution service" under the Rules and in turn an electricity network service under the NEL, despite the fact that public lighting does not involve the conveyance or control of electricity.

Notwithstanding this, to be consistent with the current form of regulation any control mechanism should be on the revenues earned over the period with a side constraint on customer charges if necessary.

3.3 Development of efficient costs

The AER notes in its Preliminary Positions Paper

The AER proposes to conduct a high level evaluation of the existing DNSP regulatory asset bases for public lighting. The AER will apply the historical asset base with any adjustments resulting from the current regulatory control period. To assist the AER in its evaluation, DNSPs must provide historical and proposed regulatory asset base and pr ovide supporting information, including

- The regulatory asset base and asset register as at 1 July 2004
- the proposed regulatory asset base and asset register as at 30 June 2009
- information to support the proposed opening regulatory asset base value.

EnergyAustralia notes that the existing excluded services Rules applying to public lighting did not formally establish an asset value, nor where revenues linked to a specific return on revenue. It will therefore be very difficult to establish a roll forward appr oach to asset valuation.

It its response to the Issues Paper EnergyAustralia accepted the fact that, as part of its regulatory proposal, EnergyAustralia will need to submit the basis of its efficient costs, including demonstration of the regulatory asset value. Implicit in this asset value are several assumptions which reflect the legacy assets which EnergyAustralia holds. For example, EnergyAustralia of necessity makes some high level assumptions about remaining life of some legacy assets. A more in dep th analysis would require an audit of around 1.3 million different assets.

We understand that businesses will differ in terms of how they establish an opening asset value. EnergyAustralia believes the Rules permit a flexible approach in this regard – the ability for a DNSP to propose a set of efficient costs (including the regulatory asset value) and the ability for the AER to assess those costs.

Further, an asset register used for accounting or tax purposes cannot be a surrogate for a regulatory asset value. Asset registers of this nature are usually a reflection of historic cost and do not provide sufficient indication of the true efficient cost of providing the service over 5 years.

3.4 Information Requests

EnergyAustralia notes that the AER has indicated the type of information that must be provided to support the proposed control mechanism and that this has also been reflected in the draft Regulatory Information Notice (RIN) released in December 2007 . EnergyAustralia notes however that there is not complete alignment between the information described in the statemen t of approach and the draft RIN. In particular the statement of approach includes a reference to justifying any material differences between historic and proposed costs. It would be appropriate for the draft RIN to also include this information so that all the required information is set out in the RIN.

We also wish to raise concerns with some of the specific information the AER has requested.

3.4.1 Asset Base

There is no confirmed RAB as at 1 Ju ly 2004. While EnergyAustralia and IPART agreed on the price that is applicable for public lighting, it should be noted that the means at arriving at that price were not consistent or agreed.

EnergyAustralia is able therefore to provide the AER with an understanding of the asset value on which services were provided as at 1 July 2004 and the changes between that asset value and the asset value that should apply at 1 July 2009

We note our uncertainty behind what is meant by an asset register. EA has a fi xed asset register which contains accounting and tax values of public lighting system assets. We do not have an asset register that contains regulatory values.

3.4.2 Historic capex

While we are able to provide historic capex for public lighting (both system and an allocation of non system), we note historic values by driver (replacement capex or augmentation capex) have not been previously reported and therefore may be more difficult to report.

The definition of registered assets is again unclear in this context.

3.4.3 Justification of any material differences between historic and proposed opex and capex costs

EnergyAustralia seeks clarification at to "proposed" (is it the proposed forecasts for the current regulatory period or those proposed for the next regulatory period?). The current form of regulation does not provide for a specific "allowance" of capital expenditure. Therefore the current regulatory framework does not require justification for expenditure variation between forecast and actuals.

If the justification is intended to be against "proposed" costs – ie. what we expected to spend at the beginning of each regulatory year, this will need to be clarified.

3.5 Service Levels

The AER makes the following commentary in section 3.5.3 of its preliminary positions paper.

"The AER considers that it is appropriate that there is a clear relationship between service levels and prices in the next regulatory period. As such, the AER will allow DNSPs to collect revenues through prices which are reflective of the costs of providing efficient public lighting services of a particular standard. The AER will apply the voluntary NSW Public Lighting Code as this standard of service level performance. The AER considers that using the standards outlined in the Code as the basis of costs and prices should ensure that there is a greater transparency for users, as raised by SSROC and the LGA."

We accept that there are linkages between the service provided, the costs of providing this service and the prices charged to customers. However, these factors should not be observed in isolation. We note concerns by customers on price impacts and in particular the difficulty of implementing significant price rises over the regulatory control period.

IPART previously addressed customer concerns as to price by constraining price increases to customers such that the revenues fell below the efficient costs of the service. IPART allowed a "transition" to cost reflectivity. It would be inevitable that in some circumstances this would come at a compromise to service levels.

The AER needs to make clear its objectives in line with the revenue and pricing principles under the NEL. If it is most concerned with service levels, then prices will need to rise commensurate with the additional costs to meet those service levels. In a regime where prices are constrained, there must be a recognition that DNSPS may need to transition to the level of service required over the regulatory control period.

If the primary concern relates to customer prices, then prices will need to transition to cost reflective levels over the period, potentially providing inadequate funding to meet desired service levels.

In summary, the price-service offering must be considered as a "package" and any service benchmark must be balanced with a proportional response in efficient costs and efficient prices. It is not appropriate for the service to public lighting customers to continue to be subsidised by other network users, as is currently the case.

4 Guideline for Materiality on pass through events

4.1 Threshold level

EnergyAustralia accepts and supports the AER's approach to identifying a threshold amount. In particular, establishing the limit based on the first regulatory year removes any uncertainty surrounding when the limit is reached in any one year. Nevertheless, to ensure complete certainty, EnergyAustralia would like the clarification that the revenue amount is the annual revenue requirement for that year and the threshold is a nominal (not real) amount.

EnergyAustralia still believes the threshold amount may be too high and has some residual concerns about the operation of the materiality threshold for pass through purposes:

- The threshold amount must recognise the new incentive-based and codified regime in which it operates.
- The threshold must be set with the revenue and pricing principles in mind.
- The AER must either recognise the potential for unforseen costs in either the pass through threshold or in expenditure allowance.
- If the AER uses the pass through provision in a similar manner to the contingent project regime for transmission, by transferring some capex into it from the program, the threshold should be such as to permit full recovery of the associated expenditure.
- The guideline must cover the related issues.

4.2 Purpose of a threshold in a highly codified, incentive based regulatory framework

The AER believes that the purpose for establishing a threshold "is linked to the ability of a business to absorb some costs – this measure is intended to address only those events that impact seriously on the DNSP's financial position". In addition the AER states

"The value of the threshold needs to take account of the capacity of the business to absorb a shock. Establishing the threshold as a percentage of revenues overcomes the problem of defining a specific amount. Larger businesses have greater capacity to absorb shocks."

EnergyAustralia finds it difficult to reconcile these statements to the new National Framework which is heavily codified and places strong incentives on DNSPs to deliver outturn expenditure which is below that considered efficient and prudent by the regulator at the beginning of the regulatory control period.

Under the previous regime (which established the 1% revenue threshold the AER intends to emulate) there was an allowed true-up of expenditure at the end of the regulatory period. IPART was able to review expenditures "ex-post" and make a determination as to whether the foregone depreciation and revenue could be recouped. Therefore the regulator had the option to ensure the DNSP was no worse off from expenditure beyond its control (but below any pass through threshold).

The new National Framework does not allow such discretion for the regulator and therefore the level of the threshold must be considered in the context of allowing a DNSP to recover appropriate return on investments unknown at the time of the determination.

We also note the concerns of the AER in establishing too low a threshold:

"Setting the threshold too low and creating a 'cost-plus' form of regulation – The extreme cost-plus form of regulation would see the businesses approaching the AER and making an excessive quantity of applications. In addition to being contrary to the regulatory framework, it would also place an inappropriate administrative burden on the AER and DNSPs."

The new National Framework is incentive based and does not allow an extreme cost plus form of regulation. The AER is only allowed to adjust the revenue allowance in specific circumstances identified in the Rules. In addition, setting too high a threshold only dilutes the incentive properties inherent in the Rules. Cost efficiencies gained by DNSPs are offset by pass through costs below the threshold.

EnergyAustralia's view is that the threshold should not be set so high as to preclude recovery of efficient costs. On the other hand, setting the threshold too low could potentially make the regulatory costs of administering the pass through arrangements outweigh the benefits of the pass through mechanism under incentive regulation. This may indicate the need for the materiality guideline to include an approach which does not rely on a threshold but which will acknowledge as material an event which results in an increase in capital and or operational expenditure such that the DNSP will not be able to meet the relevant expenditure objectives in the manner accepted by the AER at the time of the determination.

4.3 Revenue and pricing principles and recovery of unforseen costs

The AER notes

"The requirement under the NER is to set a threshold that excludes pass through events which are not material. The NER do not provide any guide to how the AER should assess materiality. In the interest of regulatory consistency the AER has taken account of thresholds set by IPART and the ICRC as well as other materiality thresholds that apply (these are set out below)."

Section 16(2) of the National Electricity Law states that when exercising a discretion relating to a distribution determination, it must take into account the revenue and pricing principles. EnergyAustralia believes the relevant revenue and pricing principles the AER needs to take into account are

- A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in:
  a. providing direct control network services; and
  b. complying with a regulatory obligation or requirement or making a regulatory payment.
- A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides.
- A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.
- Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

EnergyAustralia's interpretation of these principles in the context of the National Regulatory framework is that the AER should provide a threshold low enough to allow for a reasonable opportunity to recover efficient costs, but not too low as to make the administration of such arrangements inefficient. The AER should recognise the risk of costs incurred during the regulatory control period that are below any threshold in the expenditure allowances at the time of the determination.

4.4 Other Issues

EnergyAustralia reiterates concerns from the issues paper that were not covered in the preliminary positions paper:

- Approach to specific pass through: there is a strong inter-relationship between the forecast capital program which is incentive based on an ex ante approach, and the appetite for off-ramps (or exceptions to the rule), which has the effect of decreasing the power of the opex and capex (ex ante) incentive implicit in the Rules. In the transmission sector, EnergyAustralia notes an obvious movement toward contingent projects in circumstances where there is uncertainty as to the timing or scope of the project. A better understanding of whether the AER intends to use specific pass through events as a surrogate for the contingent project mechanism for the next regulatory control period, and the proposed approach taken, will assist with the development of EnergyAustralia's regulatory proposal. EnergyAustralia would also like an understanding of whether the approach will differ between distribution and transmission investment.
- "Dead zone" events: EnergyAustralia has raised informally with the AER the potential for a pass through event to be triggered during the current regulatory control period but after the lodgement of the regulatory proposal. The implementation of Advanced Metering Infrastructure could potentially occur in this time frame. Further guidance on how the AER would be prepared to address such issues as part of the 2009-2014 determination would be of great assistance to DNSPs in developing their approach to the specific pass through clauses they are required to submit as part of their regulatory proposal.
- "Contingent project" events: In recent electricity transmission decisions, the AER has made extensive use of the contingent project regime. Projects that the AER considers to have a level of uncertainty are excluded from the capex program and price path and are subject to a separate ex ante approval process before the price path is adjusted.

  There is no provision for contingent projects in the distribution rules; however, if the AER chooses to use the pass through mechanism in a similar manner to the contingent project regime, by transferring some capex into it from the program, the threshold for such events should permit the full recovery of costs as though they had been included in the regulatory allowance. To do otherwise would not meet the pricing principles objective in Schedule 7 of the National Electricity Law, which requires the AER to allow a network service provider "a reasonable opportunity to recover at least the efficient costs the operator incurs". The threshold for "contingent project" pass through events should therefore be such as to permit full recovery of the associated expenditure on an "as spent" basis.