570 George Street
Sydney NSW 2000

Address all mail to
GPO Box 4009 Sydney
NSW 2001 Australia

www.energy.com.au

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16 October 2008

Mr Mike Buckley
General Manager
Network Regulation North Branch
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

Dear Mr Buckley,

Response to submissions on EnergyAustralia's regulatory proposal

EnergyAustralia is pleased to provide our responses to stakeholder submissions on EnergyAustralia's building blocks proposal to the AER. The responses are outlined in the attached table. We will provide the AER with a separate letter which addresses the concerns raised by local councils on EnergyAustralia's proposal for public lighting services.

EnergyAustralia's customers are key stakeholders to the outcomes of the 2009-14 regulatory determination. In this context, we consider it important to respond to the concerns that have been raised in stakeholder submissions. Our intention in providing this submission is to assist the AER in its consideration of these issues prior to making its draft determination.

We note that our regulatory proposal submitted to the AER on 2 June 2008 addresses the majority of the concerns raised by stakeholders. Our detailed response to the submissions highlights the relevant parts of the regulatory proposal (including attachments to the public version of the proposal) where this information can be found. The AER may wish to make the attachments available to stakeholders (upon request) to more easily assist in their review of the substantial information that EnergyAustralia has provided in the proposal.

At a high level, the concerns of stakeholders relate mainly to the magnitude of EnergyAustralia's proposed capital and operating expenditure forecasts. EnergyAustralia's regulatory proposal demonstrates that the forecasts are those required to achieve the capital and operating expenditure objectives set out in the National Electricity Rules. As noted below, it is important to understand the drivers and context for these expenditure forecasts and the prudent process that EnergyAustralia has undertaken to determine forecasts.

Forecast of capital expenditure requirements

While we understand stakeholders' concerns on the size of the forecast capital expenditure requirements, it appears that submissions have not recognised the multiple drivers that underpin these requirements. For instance, a key theme of submissions was to question whether the growth in energy demand justified the growth in capex over the period. Growth related capital expenditure only accounts for 29 per cent of the proposed capital program. A broad range of drivers underpin EnergyAustralia's forecasts including the need to replace the oldest distribution network in Australia (42 per cent of the capital program). These expenditures are not driven by increases in peak demand.

Stakeholders also questioned whether EnergyAustralia's planning processes considered whether capital expenditure could be deferred to future regulatory periods. EnergyAustralia undertook a prudent capital planning process that explicitly considered deferral of projects where this would not expose us to unacceptable risk of non-compliance with licence obligations. We deferred $350 million of investment to the 2014-19 regulatory period and $250 million of investment within the period. Any further deferral of expenditure will result in significant costs to customers in future regulatory periods and will impact on the safety and reliability of the network.

Stakeholders also raised specific concerns with the demand management (DM) activities of NSW distribution businesses. EnergyAustralia has been an industry leader in the development of energy efficiency initiatives and innovative demand management programs. In particular:

- EnergyAustralia explicitly considers opportunities to use DM to defer investment as part of its capital governance processes.
- We have implemented 'tariff based' DM including Time of Use initiatives which encourage customers to shift energy use to times where network capacity is available.
- We have developed innovative strategies to educate customers on energy efficiency.

As noted in our detailed comments, EnergyAustralia has implemented significantly more DM in the current period than other NSW distribution businesses even when accounting for differences in size. Further, the capex program explicitly identifies the impact of DM on the forecast capital requirements including from deferral of investment and the impact of tariff based DM. This has been taken into account in the forecasts of capital expenditure requirements.

Forecast of operating expenditure requirements

In response to statements by stakeholders on the efficiency of the forecast operating expenditure, we note that its planning, forecasting and decision making processes are grounded in prudent considerations and are motivated towards delivering efficient outcomes.

Stakeholders also raised concerns regarding the methodology that EnergyAustralia applied to determine its operating expenditure forecasts. EnergyAustralia's methodology is consistent with recent regulatory determinations and is set out in detail in our regulatory proposal. Our response to the specific statements made by stakeholders in relation to operating expenditure forecasts are set out in the attached table.

Should you have any questions in relation to this submission please contact Ms Catherine O'Neill on (02) 9269 4171.

Yours sincerely

Trevor Armstrong
Executive General Manager (Acting)
System Planning and Regulation

EnergyAustralia's detailed responses on the statements made by stakeholders in submissions

<table>
<tr><th>Issue</th><th>EnergyAustralia response</th></tr>
<tr><td>Magnitude of capital expenditure</td><td></td></tr>
<tr><td>The Energy Markets Reform Forum (EMRF) stated:

"Across the board capex demands are massively inflated from the current period, as is opex. Against this backdrop, there is a very modest increase in consumption, and a slightly higher forecast increase in demand."(p6)</td><td rowspan="3">The drivers of EnergyAustralia's forecast of required capital expenditure are discussed in chapter 4 of its building block proposal (the proposal). These drivers include demand growth, age and condition, reliability, new connections and real input cost changes. Chapter 6 of the proposal provides evidence to demonstrate that the forecast expenditure is reasonably required to meet the capital expenditure objectives in the National Electricity Rules (NER).

EnergyAustralia's capex program is not driven solely by increases energy demand. In fact, only 29% of the capex program is growth related. As noted on p42 of our proposal, the driver of growth related capex is the disconnect between the growth rates of peak demand and annual energy. This impacts on EnergyAustralia's requirements to provide sufficient network capacity to supply all connected customers. The driver of peak demand is the penetration of air conditioning in residential premises which have a disproportionately higher impact on system peak demand compared with annual energy because they are used for reasonably short periods of time.

The condition of the network is the most significant driver of EnergyAustralia's capital expenditure accounting for approximately 42% of the forecast of required capital expenditure. The requirement for significant replacement in this period is explained by the condition of EnergyAustralia's aging network and not increases in demand.

Chapter 5 of the proposal sets out the prudent planning processes EnergyAustralia undertook to determine its forecast capital expenditure requirements. This included separate investment plans for each driver of investment. Importantly, to the maximum extent possible, synergies between these plans were used to minimise overall expenditure.

It is not valid to compare the levels of expenditure for NSW distribution businesses. The differences in capital expenditure reflect the size and particular circumstances of each network. For instance, other DNSPs will need to replace more assets in the next few regulatory periods as their networks reach the age of EnergyAustralia's network.</td></tr>
<tr><td>The EMRF stated:

"The EA application shows a massive increase in capex, far outstripping demand, and … in excess of needs…The excess claimed is ~50% of the claimed capex." (p16)</td></tr>
<tr><td>The Energy Users Association of Australia (EUAA) stated:

"Integral Energy has proposed significant capex proposals for the next regulatory period, but we note that the level of the increase is significantly less, especially relative to Energy Australia… This makes the Energy Australia capex proposals, in particular, even more curious." (p22)</td></tr>
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<td>The Public Interest Advocacy Group (PIAC) stated:

“PIAC asks the AER to ensure that the DNSP capital programs are reasonable …This is important to minimise the risk of over-recovery, which would see consumers paying for network upgrades regardless of whether they are able to be completed during the period covered by this regulation decision.” (p3)</td>
<td>EnergyAustralia has provided comprehensive information on why the forecast expenditure is reasonably required to meet the capital objectives in the Rules.

In relation to the delivery of the capital program, section 5.5 of the proposal outlines EnergyAustralia’s multi-pronged approach to ensure delivery of the forecast required capex. This is further discussed in the comments below.</td>
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<tr>
<td>Delivery of capital expenditure program</td>
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<tr>
<td>The Public Interest Advocacy Group (PIAC) stated:

“PIAC asks the AER to ensure that the DNSP capital programs are reasonable …This is important to minimise the risk of over recovery, which would see consumers paying for network upgrades regardless of whether they are able to be completed during the period covered by this regulation decision.”(p3)</td>
<td rowspan="3">Sections 6.5.4 and 5.4.2 of the proposal outline the consideration that EnergyAustralia applied to ensure efficiency of the total capital program. In preparing its expenditure forecasts EnergyAustralia considered a number of alternative development strategies for its major projects and selected the least cost alternatives. As discussed below (see comments on ‘deferring capital expenditure’), this included explicit consideration of the projects that could be deferred within and beyond the regulatory period

EnergyAustralia’s mandated licence conditions dictate the timing of capacity driven projects and, in general, do not allow deferral of these projects beyond 2014. For replacement expenditure, EnergyAustralia’s planning process considered the long term (ie:15 to 20 year) risk to the network. Replacement requirements were identified through in-depth condition and risk analysis of asset populations. Individual assets were prioritised for replacement within specified timeframes. The consequences of delaying these strategic replacement programs may result in inability to maintain effective supply to the network and further significant increases in replacement expenditure in the 2014-19 period.

In relation to the delivery of the capital program, section 5.5 of the proposal outlines EnergyAustralia’s multi-pronged approach to ensure delivery. This strategy has various projects aimed at improving efficiency within current resource limits and using external resources where appropriate including:
the standardisation of designs;
streamlining of planning and approval processes;
increasing apprentice numbers;
IT innovations, including new design software and mobile computing to improve the productivity of existing field staff;
a suite of contracting arrangements with external partners;
industrial negotiations are underway to target increases in the availability of work for accredited service</td>
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<td>The EMRF stated:

“…the AER should assess not so much that there may be a need for the capex claimed by the DBs, but whether the implementation of all these capital projects is essential to be implemented now …when resources are scarce (and therefore more expensive” (p7)</td>
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<td>The EUAA stated:

“have the DBs undertaken cost/benefit analyses to take into account the ability the DBs may have to defer the timing of capital expenditure?...how much more would it cost to undertake this capex in the next regulatory period instead of waiting for a different, more normal point in the cycle where costs are lower? …The analysis of this important matter provided by the DBs is only partial and inadequate for our purposes. “(p14)</td>
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The EUAA stated: It is arguable whether the level of capital expenditure proposed can be implemented on time and within budget with the three DBs concurrently requiring large quantities of products and services from the market which is already suffering from shortages associated with a high point in the economic cycle." (p4)	providers, which will free up internal resources to meet other deliverables; • continue existing outsourcing arrangements for civil construction and cable laying as well as some architectural design and construction; and • establishing alliance agreements with major infrastructure groups to deliver parts of the capital program in 2009-14, delivering capital outcomes in parallel with EnergyAustralia's traditional outsourcing relationships.
Deferring capital expenditure	
The EMRF stated: "…there would appear to be considerable scope for capital deferment or smoothing in the third area above (i.e. asset renewal) through targeted maintenance programs."(p13)	As noted in section 6.5.4 of the proposal, EnergyAustralia applied specific consideration to the total level of capital expenditure to ensure that it represented a prudent and efficient profile. In particular, EnergyAustralia considered the timing of the forecast over the period. Section 5.4.2 of the proposal outlines the process that EnergyAustralia undertook to defer capex within and beyond the regulatory control period. The details of these deferrals are found in Attachment 5.13A to the proposal. As a consequence of this process, EnergyAustralia: • deferred $300m replacement capital expenditure into the 2014-2019 regulatory period; and • deferred $250m capital expenditure within the regulatory period. This was achieved by identifying project deferral options that would not expose EnergyAustralia to unacceptable risk of licence non-compliance or increased operational risk from managing a larger population of assets in poor condition. In relation to asset renewal, EnergyAustralia notes that sections of the network are at or near the end of their lives. When this occurs equipment becomes subject to random failure modes which cannot be addressed through inspection and corrective maintenance because the assets are operating outside their design criteria. Should equipment not be proactively replaced, increasing levels of functional failures will occur, with associated safety, reliability and cost impacts. EnergyAustralia used a robust method for making decisions on when to replace assets. This model was audited by CSIRO and reviewed and accepted by previous regulators including ACCC and IPART. EnergyAustralia gave specific consideration to whether maintenance can be used to efficiently manage an identified failure mode. Page 47 of our proposal notes that where a failure mode cannot be efficiently managed or mitigated through maintenance practices, an asset repair or replacement decision is required.

The EMRF stated: "What has not been done is a risk assessment of the likely downside if the work is delayed…Until such an assessment is made and the risks analysed, the AER cannot approve any of the capex programs. (EMRF p13)"	EnergyAustralia has already undertaken an assessment of the risks and consequences of additional deferrals as noted in sections 5.4.2 and 6.5.4 of the proposal. The primary risk and consequences relate to the limited and narrow windows of time available to undertake maintenance, repair and replacement as well as limited opportunities to make new connections to the existing network. This is particularly relevant for investment in the sub-transmission network. If EnergyAustralia does not invest in these available windows, it would be exposed to the following consequences: • network reliability will be compromised; • future investment options will be limited; and • an overlay sub-transmission network will be required to facilitate future works, which would be at significant cost to EnergyAustralia and customers. As noted in our comments above on 'delivery of capital program', EnergyAustralia has adopted a long term risk assessment to develop its replacement expenditure requirements.
Non-network alternatives (Demand Management)	
The TEC stated: "The three NSW distribution networks have vastly under-utilised the potential of demand management (DM) to meet demand and have instead opted for an inefficient, peak-driven, asset-base expansion program. Energy Australia's (EA's) proposal stands out for its excessive claim for $8.6 billion of capex compared to a mere $23 million, or 0.26%, for DM." (p2)	As noted in the covering letter, EnergyAustralia is an industry leader in innovative demand management (DM). Our capital governance processes explicitly consider deferring investment through DM and this has resulted in cost effective DM in the current period. EnergyAustralia also uses tariff based DM such as Time of Use (ToU) initiatives which encourage customers to shift energy use to times where network capacity is available. EnergyAustralia has 400,000 customers on ToU meters and 250,000 customers being charged ToU network tariffs. EnergyAustralia is also a pioneer in educating consumers on energy efficiency initiatives. It is incorrect to assume that total capital expenditure is an appropriate indicator of the potential savings that can be made through DM opportunities. DM is not relevant for non-growth drivers of EnergyAustralia's capex program such as replacement (42 per cent of capex), customer connections, non-system capital expenditure (property and IT) and maintaining modern infrastructure standards. Further, much of the proposed investment that is "allocated" to the growth driver has multiple drivers such as replacements. If the demand driver was removed, many of these investments would still be required. EnergyAustralia acknowledges that DM activities could be used to defer some growth capex, however this type of capex only accounts for 29% ($2.4 billion) of the proposed requirements. As detailed in Section 6.7.2 of the proposal EnergyAustralia has explicitly identified the likely impact of DM from capital deferral and tariff based DM in the capital program. This is summarised below. Demand management for capital deferral EnergyAustralia has not forecast the impact of demand management on individual projects. This is because demand management projects are locational and timing specific and it is impossible to reasonably predict the

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<td>take-up of initiatives that could result in capital deferral at an individual project level two to seven years in advance.

Instead, EnergyAustralia has made provision for the costs and benefits of demand management based on results derived during the 2003-07 period at a global program level. The implementation of DM projects throughout the period is projected to result in approximately $50 million being deferred from the 2009-14 period into the 2014-19 period. Further information can be found at Attachment 5.13 to the regulatory proposal.

Tariff based demand management
EnergyAustralia has also explicitly adjusted the growth related capital expenditure forecast in the period to take into account tariff based DM. EnergyAustralia has taken this into account by adjusting the capital expenditure at a global level for the lower growth rate that is expected as a result of behavioural change. Further information can be found at Attachment 5.13.

In the context of the above summary, we note that stakeholders appear to have singled out EnergyAustralia for scrutiny of DM activities. In response, EnergyAustralia notes that it is the only NSW distributor to identify impacts on the capital expenditure program from future DM activities.</td>
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<td>The EUAA stated:

“Whilst the DBs have implemented some DM initiatives over the current regulatory period and we welcome this, these have been largely confined to trials or small scale projects. Their efforts in this area remain very limited as a result and the impact of DM stunted.”(p17)</td>
<td rowspan="2">As noted on p104 of the proposal, EnergyAustralia has a long standing commitment to investigate cost effective DM opportunities as part of its capital governance process. All growth related capital projects of material value are investigated for DM options via a screening study and further investigation. Many of these studies are available on EnergyAustralia’s website.

EnergyAustralia’s experience has shown limited scope for effective network DM relative to the overall requirement for growth capital. Notwithstanding, EnergyAustralia has achieved DM outcomes in the current period as evidenced by:

• EnergyAustralia has responded positively to the incentives under IPART’s D factor mechanism by undertaking DM projects in the current period. EnergyAustralia has received significant incentive payments relative to other DNSPs even when accounting for the size of the networks.
• During the 2003-07 period, EnergyAustralia’s DM impacted approximately $58 million worth of capital investment and resulted in a capital deferral benefit of $9 million at a cost of $5 million. EnergyAustralia has also undertaken tariff based DM activities during this time

EnergyAustralia’s DM projects have not been limited to trials or small scale pilots. In fact these types of projects are very difficult to undertake under the D factor mechanism, which only rewards projects where there is a reasonable expectation of actual capex deferral.</td>
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<td>The TEC stated:

“The failure of NSW distribution networks to utilise an adequate amount of DM has been recognised for many years. In 2004 IPART noted that the practice of addressing increasingly peaky demand with more augmentation has resulted in reduced asset utilisation, increased capex, reduced efficiency and impacts on end users. As IPART noted, 10% of EA’s network is used for 1% of the time. “(p2).</td>
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The EUAA stated: "The reasons for the low impact – past and future – of Demand Management (DM) programs on curbing peak demand should be investigated, and actions taken so that DM becomes a significant part of DBs' capital investment strategies. Under the DBs' proposals, DM will continue to remain a token gesture during the 2009/2014" (p4).	As noted above, EnergyAustralia has taken DM very seriously in the current regulatory period and has responded positively to the incentives under IPART's D-Factor mechanism. EnergyAustralia has also advocated more powerful incentives to allow DNSPs to undertake research and development on potential demand management activities. As part of our response to the consultation process on the demand management incentive scheme to apply to NSW DNSPs (January 2008), EnergyAustralia submitted that it should be allowed to recover additional revenue (0.5%-1% of total revenue or about $10m per annum) for additional demand management activities. EnergyAustralia's proposal was to allow a $10m per annum for the purpose of trialling new innovative DM options. The AER allowed $1m per annum with specific conditions as to how the money could be spent.
The TEC stated: "EA's proposal shows that the majority of new demand occurs at peak times making DM the most cost-effective approach, EA's proposal (p.43), demonstrates that peak demand is growing at almost double the rate of average demand." (p2).	As noted in our proposal, a key driver of capital expenditure forecasts is the disconnect between growth in peak demand and energy consumption. EnergyAustralia plans to meet or manage the peak demand, in accordance with the reliability standards specified in its licence. The forecast has been designed to meet these requirements and not exceed them. In EnergyAustralia's experience DM options often are not always cost effective because they often do not result in sufficient demand reductions to defer the cost of investment. This is evident in the screening studies and further investigations that we undertake as part of our capital governance process and which are available on EnergyAustralia's website.
The Total Environment Centre (TEC) stated: "Despite the generous allowance by regulators for networks to recover the cost of DM in addition to foregone revenue, the D-factor has only resulted in reductions equivalent to 7% and 3% respectively of the average annual growth in summer peak demand in NSW in 04/05 and 05/06 respectively." (p4)	It is unclear where the data has been sourced for this calculation. Regardless, it should be noted that the objective of **network** DM is not to reduce overall state demand but to impact on localised peak demand that drives distribution network expenditures. DM has to be effective for the specific load profile in question. For example, the compact fluorescent light) campaign is not going to be effective in areas where peak demand occurs during the day.
The TEC stated: "Californian regulators have ensured that utilities have secured peak reductions of 6000 MW per year and reduced overall electricity consumption by around 20,000 GWh per annum or about 7% of total electricity consumption." (p3)	EnergyAustralia is unclear on the source and context for this claim. A report prepared by the California Energy Commission ("California Energy Demand 2008-18 staff revised forecast", p3) published in November 2007 demonstrates that state-wide non-coincident peak demand in California has increased significantly since 2001 (after a decline in peak demand between 2000 and 2001). Further, the California Energy Commission is forecasting an increase in peak demand over the next decade. In summary, EnergyAustralia is actively pursuing all avenues to reduce peak demand including ToU pricing, DM projects and energy efficiency campaigns. The impacts of DM in the 2009-14 period have been explicitly taken into account in EnergyAustralia's capital forecasts.

<table>
<tr><th>Early replacement of assets</th><th></th></tr>
<tr><td>The EMRF stated:

"…there is a commercial driver for a regulated business to physically dispose of written off" assets before their technical life may be over. As such, EMRF recommend that DNSPs use a financial model to justify replacement rather than rely on condition based monitoring." (p24)</td><td>This is an incorrect observation. EnergyAustralia has a number of assets in service that are older than the standard lives of the asset class. As noted in our comments on 'the delivery of the capital expenditure program', parts of EnergyAustralia's network are at or near the end of their lives. When this occurs equipment becomes subject to random failure modes which cannot be addressed through inspection and corrective maintenance.

EnergyAustralia uses a sophisticated condition based maintenance regime to monitor asset condition and thereby enable investment managers to balance risks and costs of ongoing service of these assets. The use of such a regime is appropriate given that deterioration of assets and failures in assets generally increase as an asset ages. EnergyAustralia's replacement plan is described in Section 4.2.2 of the proposal and in more detail in Attachment 4.08 to the proposal.</td></tr>
<tr><th>Operating expenditure efficiency savings</th><th></th></tr>
<tr><td>The EMRF stated:

"…with such a significant increase in capex projects, the DBs (especially EA) should be required to provide much larger efficiency saving. " (p25)</td><td rowspan="3">EnergyAustralia's forecast operating expenditure represents the total forecast required to achieve the operating expenditure objectives in the Rules. Chapter 11 of our proposal provides further evidence to demonstrate that the forecasts reasonably reflect the operating expenditure criteria.

EnergyAustralia's planning, forecasting and decision making processes are grounded in prudent considerations and motivated toward delivering efficient outcomes which reflect the particular circumstances of our businesses. We note that:

• In section 11.4.5 of the proposal, EnergyAustralia details the explicit consideration it has given to the substitution possibilities between capital and operating expenditures. This approach ensures the forecasts represent an efficient balance between capital investment and ongoing operating costs.

• EnergyAustralia's forecasts are based on Reliability Centred Maintenance approaches, which have been in place since 2004 and which have delivered significant efficiency benefits to the business during the period. SAHA found that "EnergyAustralia meets or exceeds best practice thresholds for asset management practices [which] ensures that maintenance programs are optimised for both cost and operational performance".

• EnergyAustralia's forecasts explicitly account for deferral benefits associated with existing demand management programs and expected demand management initiatives.

• Our approach to strategic asset management (using our strategic capital development framework, our capital governance framework and our delivery strategy) demonstrates an efficient approach to forecasting both operating and capital expenditure for this period as well as future periods.</td></tr>
<tr><td>The EMRF stated:

"However, what is seen is a large step increase in opex as well as the large capex claim. It is alleged that all of the augmentation projects would result in increased opex, but opex only increases in the capex is for new "greenfields" augmentation. Increasing the size of existing hardware merely constitutes similar opex for new but larger asset."(p25)</td></tr>
<tr><td>The EUAA stated:

Performance indicators measuring operational productivity and asset productivity are needed to provide assurance at a high level that the DBs are operating efficiently and that there is a program in place for continuous productivity improvements." (p7)</td></tr>
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The EUAA stated: "Integral Energy has covered the important issue of productivity very explicitly by detailing their strategy towards efficiency savings, trade off between capital expenditure and opex, as well as benefits from Demand Management." (p21)	EnergyAustralia has not reduced its forecast inputs (ie labour) as an offsetting mechanism against productivity. Rather productivity is implicit in the forecasts provided. In this context EnergyAustralia notes: • We adopted the average labour based escalator for the electricity sector even though historic evidence suggests labour escalation in EnergyAustralia's network area is higher than the average due to its CBD location and difficulty in attracting appropriately skilled staff. • We adopted a labour based escalator for "non-system" related labour costs which is below the escalator for the electricity sector; • While we included a real cost escalator on contracted services (eg. tree trimming, meter reading, labour hire, other general contracts etc.) we did not apply any real cost escalation for non-labour components of operating expenditure. Attachment 5.15 to the proposal provides supporting evidence for the labour escalations used to forecast operating expenditure. An arbitrary reduction would not reflect the realistic price of labour or would require EnergyAustralia to reduce the quantity of labour utilised. Neither option would be prudent in the circumstances of EnergyAustralia given its strategy for delivery of a record capital program.
Operating expenditure variations	
The EMRF stated: "The EMRF is very concerned with the accuracy of the EA actual opex for 07/08. The previous year the opex was some $370m yet it rose by $104m the following year, an increase of some 30%. This indicates there is an error, EA is playing games or EA is not able to manage its business in a sensible manner."(p26)	EnergyAustralia has started with the 2006-07 actual operating costs as the starting point for its forecast. As explained in section 10.1.6 of the proposal, EnergyAustralia removed $46 million ($08/09) from the starting point to ensure only ongoing recurrent costs were used as the basis for forecasts. As a result, the increase in opex between 2006-07 and 2007-08 is approximately 13.8%. The variance between 2006-07 and 2007-08 is discussed in section 10.1.8 and is mainly driven by real increase in labour, the additional increase in opex from the approved pass through for the DRP licence conditions and other increases such as land tax, property and insurance.
The EMRF stated: "The EA application shows a very high start value for opex compared to the IPART allowance which should not be expected to be in error by over 30%" and "It is impossible to accept that IPART was so wrong for its estimate for 07/08 (an error of some $90m), when for the other two DBs the IPART assessment so closely matches the amounts of opex actually used. Equally, it is hard to accept that EA is so demonstrably incompetent."	In section 10.1.2, EnergyAustralia has addressed the issue of the variance between actual opex and the forecasts at the time of the 2004 determination. This analysis shows the impact of forecasting errors at the beginning of the period and the compounding nature of the errors over time. The variance between the regulatory allowances and actual 2006-07 expenditure is largely represented by changes in cost inputs and incidental increases in operating costs to support a capital. The factors for the variances are set out in section 10.1.5. It is important to realise that EnergyAustralia lost value under the opex incentive framework as a result of spending opex in excess of the allowance. That is, the business will never be compensated for opex that is higher than the allowance despite the fact that these costs are legitimate and reflect real network assets.

The EMRF stated: "The EA claim is totally inconsistent with conventionally accepted criteria for a step change." (p27)	Information on EnergyAustralia's operating cost model (which was used to determine the forecast of expenditure for 2007-08) is set out in section 10.2 of the proposal. EnergyAustralia has started with the 2006-07 actual operating costs as the basis for its forecast. These costs have been examined to establish how they are likely to change over time taking account of factors that drive workload, input costs and step changes in activities that may result from external factors such as the introduction of a new obligation or business function (ie an assessment has been made of the fixed and variable component at activity levels). These escalators are applied to the variable portion of each activity cost. Sections 10.2.2 (step changes), 10.2.3 (workload escalators), 10.2.4 (price escalators) of the regulatory proposal provides more information on this process. EnergyAustralia has used the term "step change" to identify systematic changes in costs that are on-going (ie: recurrent costs). Examples of this include increases in system and non-system operating costs associated with the investment of new capital i.e. new substation sites incur new rates and land taxes, new IT systems incur new licence and support fees. The term "step change" does not equate to "one-off change". EnergyAustralia agrees that one-off changes/adjustments to operating costs should not be included in the base year costs upon which forecasts are made. As noted above, EnergyAustralia made specific adjustments to base year costs to ensure this did not happen. The recurring operating costs in EnergyAustralia's regulatory proposal are legitimate and justifiable.
Cost Escalation	
The EMRF stated: End users would urge the AER to seek robust independent analysis of the cost escalators and the ability of the DBs to efficiently manage them. We are concerned that the DBs be required to apply rigorous cost management disciplines across their businesses to ensure that costs are being minimised and their proposals do not contain elements of cost padding or slack management due to their regulated monopoly status. The regulatory reset is the only chance of ensuring this. (p14)	EnergyAustralia engaged an independent consultant (CEG) to develop a methodology for forecasting real cost escalation. This is at Attachment 5.15 to the proposal. The method used by CEG is a similar approach to what was adopted by the AER and their consultants in the recent regulatory decisions including the ElectraNet regulatory determination. EnergyAustralia will continue to use rigorous cost management approaches. In the case of materials and equipment procurement, Energy Australia uses contractual arrangements to appropriately manage material price risk. For contracted services such as civil construction, Energy Australia procures these through a competitive tendering process. Labour costs have been forecast based on the average wages in the electricity sector even though historic evidence suggests labour escalation in EnergyAustralia's network area is higher than the average due to its CBD location and difficulty in attracting appropriately skilled staff. The sector is currently facing a skills shortage which requires businesses in this sector to provide wages sufficient to attract appropriately skilled people. EnergyAustralia has been proactive in trying to increase the supply of labour with electrical skills through extensive apprentice programs.

The EMRF stated: ““Much of the capex budget is in relation to construction cost, which is driven by construction wages and materials costs.”	This is incorrect. As shown in figure 5.8 of our proposal, over the 2004-09 period, civil construction represented 15% of capital expenditure.
The EMRF stated: “EMRF provide evidence from EconTech and what appears to be CEG’s report to show that “provides clear evidence that there is no need at all to increase the allowance for capex to reflect rising construction wages growth.” (p19)	This statement is incorrect. This does not recognise the distinction between rates of change and absolute changes. While the rate of growth in construction wages is not increasing at the same rate as other wages, construction wages are increasing in real terms. Wages are only a component of construction costs. Independent forecasts set out in Attachment 5.15 to the proposal indicate that total construction costs are not forecast to increase at the same rate as the recent past but they are still forecast to increase by around 1.4% pa in real terms over the next regulatory period. This needs to be factored into forecast capital costs otherwise allowed revenues will be insufficient to fund forecast capital projects.
“In fact, there is an argument that construction wages are falling relative to average wages”	
The EMRF stated: “The clear import of this data is that the DBs have been experiencing a premium of wages growth over average wage growth equivalent to that forecast by CEG, but in the current regulatory period, and despite this premium have been able to constrain their operating expenditures at the same time.”	This statement is incorrect. EnergyAustralia’s opex for the 2004-09 period will be significantly above the forecast amount in the 2004 determination. A key driver of the higher than forecast opex was that real labour costs were higher than assumed in the 2004 determination. This was due to significant skills shortages in the EGW sector which resulted in higher real wages compared to average wages. EnergyAustralia’s labour escalation is based on independent forecasts of wages growth in EGW sector and is driven by continuing skills shortages that will occur over the period. The effect of labour escalation is to ensure that revenues are based on the expected cost of labour in the 2009-14 regulatory period. There is no reason to assume that the labour costs in the 2004-09 regulatory period will necessarily be the same as the 2009-14 regulatory period.
The EMRF stated: “..there is no basis to allow any premium for expected wages growth over the coming period as there is no step change between the current period and the next period in respect to wages growth.”(p32)	

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<td>The EMRF disputed CEG's view that increases in the costs of materials are likely to further increase in real terms from now on. EMRF show movements in the LME since the report by CEG which shows that over past five months, there has been:
• 5% fall in aluminium for 27 month forward buying.
• 10% fall in copper for 27 month forward buying.
• static future crude oil price with some volatility.]</td>
<td rowspan="2">As noted in Attachment 5.15, CEG developed forecasts based on LME forward prices (for the period for which they were available) and an average of independent forecasts for the period beyond.
It should be noted that commodities are priced in $US and that Australian businesses are exposed to movements in Australian dollar which impacts real commodity prices to Australian businesses. The Australian dollar is significantly influenced by movements in commodity prices and as a result reductions in commodity prices will be associated with an offsetting depreciation of the Australian dollar. This is noted in Attachment 5.15.

The forecasts contained in EnergyAustralia's capital proposal assumed the following movements in commodity prices (as at 5 March 2008).
<table>
<tr><th></th><th>Change $US (2008-2014)</th><th>Change $AUD (2008-2014)</th></tr>
<tr><td>Copper</td><td>-13.1%</td><td>-8.5%</td></tr>
<tr><td>Aluminium</td><td>+13.5%</td><td>+19.6%</td></tr>
<tr><td>Crude Oil</td><td>+13.4%</td><td>+19.5%</td></tr>
</table>
</td>
</tr>
<tr>
<td>The EMRF stated:

"Whilst the new data does indicate that in some ways input prices could increase, they also show that some input costs are reducing." (p14)</td>
</tr>
<tr><th>Cost of capital</th><th></th></tr>
<tr>
<td>The EMRF stated

"The EMRF therefore expects the AER to carefully assess those few aspects where it has discretion, to ensure that it recognises the essential fact that the financial market is robust and not be misled by the DBs that sourcing the capital they need will be more expensive than it really is." (p34)</td>
<td>As noted in section 8.3 of the proposal, EnergyAustralia has used the deemed parameters and calculations specified in the transitional Rules. Where the Rules require the use of market parameters, EnergyAustralia has used the values in recent AER regulatory determinations for the purpose of providing an indicative price path. Actual market parameters will be used to calculate the value of WACC in the AER's determination.</td>
</tr>
<tr><th>Demand and Consumption forecasts</th><th></th></tr>
<tr>
<td>The EMRF stated:

"It would also be useful to aggregate all of the claims by the distribution businesses against the values used by NEMMCo and TransGrid as the basis for setting generation adequacy and forecast transmission usage and demand." (p36)</td>
<td>This information is available in Transgrid's 2008 Annual Planning Report (page 86) which provides a comparison of TransGrid's peak demand forecasts with the aggregate forecasts of NSW DNSPs. EnergyAustralia considers that such a comparison would not provide any meaningful evaluation on the merit of EnergyAustralia's demand forecasts. EnergyAustralia's capital program is, in part, influenced by demand at a spatial level. There is little relevance of TransGrid's peak demand to EnergyAustralia, particularly as EnergyAustralia contributes less than half of the state peak demand.</td>
</tr>
</table>

The EUAA stated: "What is the MW contribution of residential air conditioners to the peak demand – both actuals for the 2004/2008 period, as well as forecasts for the 2009/14 period? What was the methodology adopted to arrive at these figures?" (p12)	Section 3.5.1of Attachment 13.2 to EnergyAustralia's proposal sets out the 2008 and 2014 estimated breakdown of peak demand by customers with and without air conditioning, and the methodology behind the estimates. It should be noted that a footnote to Table 3.1 in Section 3.5.1 was inadvertently omitted from Attachment 13.2 and should have read: "Estimates of sectoral contributions to peak demand shown above are before adjustment for global warming and time-of-use tariff impacts". The respective figures for 2004 are: Summer, customers with air conditioning = 1,277 MW; Winter, customers with air conditioning = 1,448 MW.
The EUAA stated: "On a broader scale, has any form of end user demand forecasting been done, as a bottom-up method of forecasting system demand, to act as a double check of the main methods described in the regulatory proposals? If not, what are the reasons for not doing such a double check, given the pivotal role of peak demand forecasts in all proposals? Unless there are valid reasons to the contrary, we would urge the AER to insist on this work being done by the DBs for this review to ensure robustness in their proposals." (p12).	Appendix C of Attachment 13.2 of EnergyAustralia's proposal sets out, in detail, the end-use approach adopted to forecast residential energy consumption. With regard to peak demand forecasts, it is considered that the adopted end-use approach, of distinguishing between customers with and without air conditioning, is an appropriate level of end-use detail. EnergyAustralia has provided detailed information in Attachment 13.2 of the proposal to demonstrate that it has thoroughly analysed all issues relating to peak demand and energy forecasts.
The EUAA stated: "it is reasonable, and indeed necessary, for the AER to satisfy itself that the DBs have thoroughly analysed all the issues relating to demand and energy forecasts… and all options to manage them, as part of their case for their exceptionally large capital expenditure programs." (p12)	In relation to managing peak demand, EnergyAustralia is an industry leader in demand management (DM) and has an extensive track record of implementing demand management projects that defer capital investment and influence energy consumption behaviour. Specifically, page 104 of the regulatory proposal notes the impact of tariff based demand management initiatives on peak demand and energy growth. EnergyAustralia has made an explicit adjustment to the growth related capital forecast in the regulatory period. This adjustment considers, among other things, the proportion of peak demand attributable to time of use customers. The methodology of applying this adjustment is outlined in Attachment 5.13 of the regulatory proposal.
The EUAA stated: "The EUAA would suggest that, if not already being done, DBs should investigate the potential impacts of an extended MRET target on the DBs' proposed forecasts of peak demand, annual energy capital and operating expenditure and service level standards such as reliability and power quality." (p12)	Section 1.4.2 of Attachment 13.2 to EnergyAustralia's proposal clearly specifies that EnergyAustralia's submitted forecasts do not, for a number of key reasons, allow for the impact of the highly uncertain future trend in electricity prices. The network faces costs that are not driven by demand. The investment costs of not meeting these requirements must be met through revenues to support these investments.

Pass Through	
The EUAA stated: "The EUAA agrees with the Australian Energy Regulator's view, expressed at the NSW public forum on 30 July 2008, that pass throughs need to be tightly defined in the first instance so there is a proper sharing of risk between business and consumers, and that the distributors should not use pass throughs to remove all risk." (p19)	A pass-through mechanism has been established in the Rules for a specific purpose of providing a risk management mechanism. EnergyAustralia has proposed pass-through events as part of its regulatory proposal, which it believes manages risks outside of the control of the business and to which non-regulated entities would be able to pass through. Chapter 15 of the proposal provides more information.