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EnergyAustralia®

6 March 2009

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

Dear Mr ~~Buckley~~ Mike,

Response to stakeholder submissions on AER's Draft Determination

EnergyAustralia has reviewed stakeholder submissions on the AER's draft determination for NSW, ACT and Tasmanian network service providers and would like to respond to the issues raised. In doing so, we have also taken the opportunity to respond to stakeholder comments on the revised proposals of network service providers including EnergyAustralia.

Most issues raised by stakeholders have been addressed in our June 2008 regulatory proposal and revised proposal and interim submission of January 2009. The purpose of this latest submission is to clarify our approach to revising elements of our regulatory proposal in the context of specific stakeholder responses and to direct stakeholders and the AER to the relevant sections of our proposal for more detail. Our detailed responses are set out in the attached table.

EnergyAustralia has used best endeavours to respond expediently to the issues raised by stakeholders to provide the AER with sufficient time to fully consider our submission. While our detailed comments are provided in the attached table, EnergyAustralia would like to make some high level comments on the major issues raised by stakeholders relating to:

- the impact of higher network prices on energy users, particularly disadvantaged customers;
- the impact of deteriorating economic conditions on capital expenditure forecasts; and
- the need to incorporate a growth factor adjustment to address the uncertainty relating to energy forecasts.

Stakeholders expressed concern over the proposed increase in prices for network services. We recognise that an increase in network electricity prices will impact consumers of electricity, particularly disadvantaged customers. EnergyAustralia actively supports measures aimed at minimising the impact of prices on low income households. We believe that these initiatives are most effective when they are dealt with at the "whole of bill" level rather than through economic regulation of network services.

EnergyAustralia's retail business has a number of initiatives in place to ease financial pressures on disadvantaged customers. We are investing more than $3.5 million on a program to help customers who have long term difficulty paying their electricity bills. Such programs complement the initiatives of State and Federal governments to provide household assistance to low income households.

Our retail business also undertakes a number of measures aimed at promoting energy efficiency, which should assist domestic and commercial customers to minimise their energy bills. For instance, we fund community groups to provide 'no interest' loans on essential energy efficient appliances such as fridges. EnergyAustralia also offers energy efficiency advice, energy audits and installations. In addition to this, our network and retail businesses have been at the forefront of trialing and implementing interval and smart meters technology in homes and businesses and tariff design that helps give customers more control over their electricity bills. More information on these initiatives is provided in our detailed response.

We would also like to provide stakeholders with more information on the drivers of the increase in network prices over the forthcoming period. In part, the proposed price increase is a result of the past distribution regulatory regime which has not kept pace with EnergyAustralia's capital and operating expenditure requirements. For instance, at the beginning of this process the average real price paid by EnergyAustralia's customers for the use of our network was lower than it was 10 years ago despite a significant increase in capital requirements over the period. EnergyAustralia estimates that a price adjustment of 18.6 per cent is necessary to rectify the legacy of previous regulatory decisions.

EnergyAustralia also notes that the price increase is related to significant investment in renewing the network. A large proportion of EnergyAustralia's network was built between 1965 and 1980 and its age is therefore approaching, or above, 40 years old. EnergyAustralia notes there would be unacceptable risk (and additional costs) in future periods in terms of the performance, safety and reliability of the network if we do not begin this investment to renew the network in this period.

Stakeholders also questioned the extent to which businesses have considered the impacts of deteriorating economic conditions on capital expenditure forecasts. EnergyAustralia's revised proposal has been prepared to address specific matters raised by the AER's draft determination. In doing so, EnergyAustralia has specifically considered the impact of deteriorating economic conditions on investment requirements in the period. It is important to note that growth related capital expenditure is less than 30 per cent of our capital program. The other key drivers of the investment program such as replacement and capital expenditure to meet new licence requirements are not affected by deteriorating economic conditions.

EnergyAustralia's revised capital expenditure forecast is $356 million lower than the June 2008 proposal (excluding equity raising costs). This includes:

- A reduction of $234 million in growth related capital expenditure to account for lower peak demand forecasts from deteriorating economic conditions. This represents a 10 per cent reduction in growth related capital expenditure over the next regulatory period compared to the June 2008 proposal.
- A further reduction of $145 million to take into account most up to date forecasts of real cost escalators over the next regulatory period.

In relation to the AER finalising its determination, we note that one of the capital and operating expenditure factors the AER must take into account under clauses 6.5.6(e)(3) and 6.5.7(e)(3) is any analysis undertaken by or for the AER and published before the distribution determination is made in its final form. We look forward to the opportunity to review and respond to any material or analysis that the AER proposes to take into account when making its final determination relating to economic conditions. Specifically, we look forward to addressing any material or analysis that relates directly to the AER's decisions on capital or operating expenditure, such as peak demand forecasts, as well as material relevant to its other constituent decisions such as the control mechanism, X factors and the energy forecasts relied upon to make those decisions and the financial conditions in the market.

A further issue raised by stakeholders concerns the uncertainty relating to energy forecasts for the next regulatory period. In our revised regulatory proposal, we proposed a growth factor (G-Factor) adjustment in the control mechanism to symmetrically protect revenues from falling and rising as a result of significant fluctuations in actual energy volumes compared to forecast.

Integral Energy supported our proposal for a G factor in the control mechanism for NSW DNSPs but considered that the adjustment should be limited to out-turn volume changes relative to the forecasts underpinning the final determination. EnergyAustralia considered this option when developing our proposed G factor arrangement. However, on balance, we found an adjustment based on revenue to be more transparent in addressing the problem of inherent uncertainty in volume forecasts. We will seek additional information from Integral and welcome joint discussions with the AER on this issue.

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
System Planning and Regulation

Encl.

Attachment – EnergyAustralia's response to stakeholder submissions on the AER's draft determination

Stakeholder	Page	Stakeholder comment	EnergyAustralia response
Issues relevant to Part I, Chapter 3-6 of EnergyAustralia' proposal (Capital expenditure)			
Impact of economic growth on capital expenditure requirements			
EUAA	15	"…the DNSPs, apart from Integral Energy, have elevated their capital expenditures above their June 2008 figures and well above the AER determinations; this is extraordinary in an environment of economic downturn. This applies particularly to Energy Australia and we fail to understand why their revised proposal should increase capex significantly above what was already a highly questionable original proposal."	The statement made by EUAA in its submission is incorrect. Chart 8 (p16) of the EUAA submission shows that EnergyAustralia has reduced its forecast of capital expenditure for the 2009-14 period. We have reduced our forecast growth related capex forecasts by more that 10 per cent in response to expected lower peak demand based on more up to date information. Our revised forecast of capital expenditure is $356 million (or $177 million including equity raising costs) lower than the June 2008 proposal. The revised forecast total capital expenditure is $8.303 billion (excluding equity raising costs). This compares with our total of forecast capital expenditure in the original proposal of $8.659 billion. The revisions clearly take into account the lower peak demand forecast over the period and updated cost escalation data based on current economic conditions. This is discussed in our responses to specific issues below. Any comparison between the original and revised forecast of capital expenditure should exclude equity raising costs. EnergyAustralia included equity raising costs in the revised capital expenditure forecast to address the AER's preference that equity raising costs be capitalised rather than included as operating expenditure.

Origin	3	"Origin submits the AER take further account of the economic downtown, in relation to capital programs, operating expenditures and demand forecasts with a view to ensuring expenditure for the next regulatory period remains at efficient levels."	EnergyAustralia notes that its revised forecast capital expenditure is $234 million lower than the original proposal to take into account lower peak demand forecasts. This represents a reduction of 10 per cent of growth related capital expenditure compared to the original proposal. We also note that capital expenditure associated with peak demand growth accounts for less than 30 per cent of total forecast expenditure. In revising our capital expenditure requirements, EnergyAustralia undertook a 2 step process: 1. The energy and global peak demand forecasts were revised to take account of more up to date economic growth projections as well as the impact of electricity price movements, which had become more certain since the June 2008 proposal with the release of information relating to the CPRS, various NSW government levies and the AER's draft determination for the period 2009-10 to 2013-14. Attachment 13A to the revised proposal sets out the details behind the revised volume forecasts. 2. The impact of the revised global peak demand forecasts on capital expenditure was, due to time constraints, undertaken as a high level review. EnergyAustralia considered the impacts of revised peak demand forecasts on growth related capital expenditure which was set out in its Area Plans, 11kV development plan and low voltage capacity plan. For instance, EnergyAustralia undertook a high level review of the impact of revised peak demand forecasts on its Area Plans and consequently deferred capacity driven projects which were due for completion after 1 January 2012 by up to 12 months. Further information on the process EnergyAustralia undertook to consider the impacts of the revised peak demand forecasts on growth related capex is set out at Attachments 3A, 3B, 3C and 3D of the revised proposal. As noted on page 14 of Attachment 13A to the revised proposal, the revised global summer peak demand forecast is 3.1% lower in 2013/14 than the June 2008 forecast. Half of this reduction (1.6%) is a result of the more
EUAA	9	"The economic downturn will also result in reduced demand for electricity which will have flow on effects, including in that portion of capital expenditures aimed at meeting forecast network growth."	
EMRF	12	"In particular, capital programs proposed by the DBs must be reassessed in terms of the impact such large reversals of previously accepted growth forecasts will cause."	

			pessimistic economic outlook, and the other half (1.5%) of the lower forecast is due to the assessed impact of the assumed electricity price increases.
EMRF	26 5	"The EMRF is of the view that growth is likely to be much lower than forecast as a result of the economic downturn. If the expected growth is much lower than forecast much of the capex targeted to address growth becomes unnecessary." "The increases in capex and opex were supposedly justified on significant growth in electricity demand, yet the movements in economic growth in Australia and particularly NSW since the middle of last year have all evaporated and the next few years will see either very low growth or recessionary conditions, and hence, little or no growth in electricity demand. To assume a high growth path for the NSW economy as do the draft decision and the applications is simply wrong."	The comments made by EMRF focus on growth driven capital expenditure. It should be noted that load growth and resulting network capacity constraints account for approximately 30% of EnergyAustralia's capital program. The remainder of the program is driven predominantly by asset condition, and mandatory reliability, environmental and regulatory standards. In relation to growth related capital, EnergyAustralia took account of the most up to date economic projections available at the time the revised proposal was submitted. The GSP projections used to develop the revised peak demand forecasts were: ▪ 0.50% growth in 2008/09 (ANZ forecast) ▪ 1.25% growth in 2009/10 (ANZ forecast) ▪ 2.78% growth in 2010/11 to 2013/14 (being the average of the KPMG Econtech's October 2008 forecasts for the last four years of the regulatory period). These economic growth assumptions were published by independent experts. The resultant economic growth profile was for reasonably weak growth in the first year of the regulatory period, followed by a strong recovery in NSW economic growth for the final four years of the period. EnergyAustralia notes that an independent expert (Oakley Greenwood) reviewed EnergyAustralia's processes for revising energy and peak demand forecasts. Oakley Greenwood's full report is at Attachment 13B to the proposal. It found that (p5): "… EnergyAustralia's approach to the development of its revised energy and demand forecasts to be based on sound principles and to be prudent given the inherent risks of the changes outlined."

City of Sydney	3	"EnergyAustralia is now anticipating a reduction in total energy consumption of 10 per cent. In this context of falling energy consumption, the forecast increase in peak demand of about 14 per cent over the same period appears all the more dramatic."	In order to ensure that our forecasts reflect a realistic expectation of the future period, EnergyAustralia has relied, where possible, on independently produced projections of the drivers of energy and peak demand growth, and price elasticity estimates which have been recommended by NEMMCO. A key driver of the revised forecasts is the reductions in energy volumes resulting from electricity price increases expected over the regulatory period. However, the NEMMCO price elasticities relate to energy consumption, not peak demand. The likely elasticity of peak demand to price is not significant enough for us to conclude that our capital expenditure requirements will be lower than our revised forecast. Our experience is that customers will react to price changes by conserving their energy usage on relatively mild days, but are unlikely to materially change their consumption habits on the few extreme temperature days which are experienced each year. For example, EnergyAustralia notes that air conditioners (the key driver of peak demand events) are still likely to be used by consumers on days of extreme temperature despite a price in the general level of electricity prices. In our Further Submission of February 16, EnergyAustralia noted recent electricity growth trends in South Australia which support the contention that peak demand is less sensitive to price changes than annual consumption. This information is set out on p12 of the Further Submission. EnergyAustralia has also relied on Oakley Greenwood's independent expert advice in respect of our demand forecasts: "It is also our view that these price increases, in combination with changes in attitudes toward and responsibility for greenhouse gas emissions will result in material reductions in total electricity consumption, but very small if any associated reduction in peak demand growth. This growth in peak demand on NSW's electricity networks is being driven by air conditioning load.

			Without very dynamic pricing options being made available (which will be difficult due to metrology limitations that will persist during most of this regulatory control period) the propensity for residential customers to use air conditioners on high temperature days is well proven – even if they economise in other ways (including reducing air-conditioner use on milder days) to reduce overall electricity use and cost”
EMRF	12	“The impact of the loss in buying power by some 30-35% due to currency movements will have a major impact, as will the general loss of consumer buying power resulting from the economic downturn. The impact of this loss of buying power will be to reduce the incidence of new electrically driven equipment, especially residential air conditioners which are one of the large drivers of demand growth.”	The impact on the price of major electrical appliances of the significant fall in the $AU against other countries is expected to be offset by a fall in the price of air-conditioning equipment that has been occurring since 2005. The Australian Bureau of Statistics reported that consumer prices fell 0.4 per cent in the December quarter, led by an 18 per cent slide in the price of petrol along with a 2.4 per cent fall the price of cars. Despite a lower Australian dollar, which would normally push up prices of imported items, household appliance prices fell 0.6 per cent and computing equipment prices 2.9 per cent. Further, EnergyAustralia notes that air conditioning penetration rates were strong throughout the 1990s despite the exchange rate being at current levels. This economic evidence suggests that despite the current economic downturn, global economic factors will continue to influence the price of air-conditioners available to customers in future.

<table>
<tr>
<td>Origin</td>
<td>5</td>
<td>“… (Origin is) concerned with the predicted increases in labour and material costs based on earlier periods which suggests the data relied upon regarding labour and material cost growth is ceasing to reflect actual changes. Clearly all economic data is pointing to stable labour and reduced material costs (see copper and aluminium indices above) in 2009-10 compared with the 2006-07 and 2007-08 financial years.”</td>
<td>EnergyAustralia revised its forecast of capital expenditure to address issues raised in the AER’s draft decision, by taking account of most up to date information for cost escalators. EnergyAustralia used the most up to date information available at the time which took into account the current economic outlook. The revised cost escalators resulted in a reduction of capital expenditure of $145 million compared to the June 2008 proposal.

As can be seen from the table below, Energy Australia’s revised cost escalators for copper and aluminium take into account latest forecasts of material prices.

June to June escalation factors for EnergyAustralia
<table>
<tr><th></th><th>June 2007</th><th>June 2008</th><th>June 2009</th><th>June 2010</th><th>June 2011</th><th>June 2012</th><th>June 2013</th><th>June 2014</th></tr>
<tr><td>Copper</td><td>-8.4%</td><td>-6.7%</td><td>-14.8%</td><td>-4.1%</td><td>7.1%</td><td>5.6%</td><td>-6.0%</td><td>-6.4%</td></tr>
<tr><td>Aluminium</td><td>1.0%</td><td>-15.9%</td><td>5.3%</td><td>7.6%</td><td>6.6%</td><td>3.5%</td><td>-0.8%</td><td>-1.1%</td></tr>
<tr><td>Crude oil</td><td>-12.6%</td><td>29.4%</td><td>-0.2%</td><td>0.9%</td><td>6.8%</td><td>2.9%</td><td>0.3%</td><td>-1.0%</td></tr>
<tr><td>Steel</td><td>-7.3%</td><td>5.8%</td><td>42.9%</td><td>-8.2%</td><td>2.1%</td><td>-3.8%</td><td>-4.7%</td><td>-5.0%</td></tr>
<tr><td>EGW wages</td><td>1.2%</td><td>1.4%</td><td>3.3%</td><td>3.6%</td><td>3.2%</td><td>2.9%</td><td>2.4%</td><td>2.0%</td></tr>
<tr><td>General labour</td><td>0.6%</td><td>0.9%</td><td>0.7%</td><td>1.3%</td><td>1.7%</td><td>1.7%</td><td>1.4%</td><td>0.8%</td></tr>
<tr><td>Construction</td><td>0.5%</td><td>1.1%</td><td>0.4%</td><td>1.0%</td><td>2.3%</td><td>1.1%</td><td>-0.8%</td><td>-0.7%</td></tr>
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EUAA	16	“The current global economic woes have seen falls in materials costs domestically and globally. The Reserve Bank of Australia’s Index of Commodity Prices shows a decrease in commodity prices of 4% in December 2008.”	EnergyAustralia notes that its cost escalators reflect the expected price of materials at a detailed level. It is not appropriate to apply a general commodity price index to determine cost escalators. The data provided by EMRF of recent movements in commodity prices, is expressed in $US. The quoted declines in material prices need to be adjusted for corresponding movements in the Australian dollar to reflect the impact of commodity prices on Australian businesses. It is important to note that the $AU has declined by more than 30 per cent since the start of the year.
EMRF	13	“The EMRF has also pointed out that the premiums for specific labour and materials used by the DBs and the AER have already been allowed for in the base capex and opex allowances, and by applying these ”real cost escalators” to the whole amount of the capex and opex is effectively double counting.”	The base capital and operating expenditures are based on actual labour rates and reflect current costs. The application of real cost escalators does not “double count” and purely indexes current costs for forecast real cost movements. EnergyAustralia's cost escalation model is very detailed and has been scrutinised by the AER and audited by PWC. The detailed nature of this model not only ensures that there is no double counting, but that only the relevant escalator is applied to that cost component. For example, if only 10% of the cost of a substation is attributable to skilled labour, then the electricity, gas and water (EGW) index is applied to only 10% of the substation costs. Further, where the required unskilled labour, for example civil construction, then a general labour index is applied to that portion of costs attributable to unskilled labour.

EMRF	14	".. the AER should not just increase allowances for opex and capex by the "real" increases in sectoral labour rates but to discount the base productivity (ie: premium of wages over inflation) from any increases that sectoral labour rates might be indicating."	EnergyAustralia updated its labour costs forecast to be consistent with the AER's proposed method to apply KPMG Econtech's forecasts. While we have concerns with relying on one forecaster, we consider it appropriate to use latest data on forecast labour costs. Specifically in relation to the EMRF's comments concerning the premium of wages over inflation, we note that the EMRF have not considered that productivity in particular sectors can differ markedly from the overall economy average. In the case of the Electricity, Gas & Water sector, changes in productivity are heavily impacted by the investment cycle. In this respect we note the comments of the Productivity Commission (http://www.pc.gov.au/research/productivity/primer/measures) which states that: "Labour productivity should be interpreted very carefully if used as a measure of efficiency. In particular, it reflects more than just the efficiency or productivity of workers. Labour productivity is the ratio of output to labour input; and output is influenced by many factors that are outside of workers' influence - including the nature and amount of capital equipment that is available, the introduction of new technologies, management practices and so on." Since capital equipment in the EGW sectors have long lives, there are periods where significant capital investment is required to replace or refurbishment significant elements. This is illustrated by the ABS Experimental Measures of Industry Multi-Factor Productivity (ABS Cat. No. 5260.0.55.001 Information Paper)which show that in the EGW sector: ▪ Multi-factor Productivity (Gross Value Added Based) increased 1.5% on average since 1985 but has declined by 2.5% on average between 1988/89 – 2005/06. ▪ Gross Value Added (chain volume index based) increased 2% on average since 1985 but has increased by 1.1% on average between 1988/89 –

			2005/06. ▪ Labour Productivity in the EGW sector increased 4% on average between 1985 – 2005/06 but has declined by 3.5% on average between 1988/89 – 2005/06. ▪ Capital inputs increased 1.9% on average between 1985 – 2005/06 but increased by 3.3% on average between 1988/89 – 2005/06. It is anticipated that productivity in the EGW sector will continue to fall until the period of major investment, primarily driven by replacement and refurbishment, returns to a levels which reflect an average level of investment. In terms of productivity at a project level, all our project costs have been estimated on the basis of generic estimates that have been independantly compared against industry benchmark data.
EMRF	16	"The AER has built into its escalators, a real increase of 4.1% for the entire five year regulatory period. The market is showing that land prices (especially residential land in NSW) are at best static if not actually falling, and with increasing office vacancies the value of commercial land is also falling. This is a result of the current economic conditions. For the AER to factor into its allowances for the DBs, a strong increase in land values is patently out-of-step with the current actual market conditions."	EnergyAustralia proposed a land cost escalation methodology based on independent forecasts. This was rejected by the AER who considered that a more appropriate approach was to use historical average movements. EnergyAustralia's forecast and the AER's long term average resulted in an equivalent rate of escalation. The forecasting of land prices is difficult, which suggests that an approach based on longer term movements in prices is not unreasonable.
Reliability capex			
EMRF	26	"The fact that the service standard performance to date has exceeded requirements raises the question as to whether capex in addition to that included in the current capex allowances is necessary to achieve the licence levels set by the government."	EnergyAustralia has performed well against the reliability standards set by DWE in recent years. However, it should be noted that the DWE licence conditions require improvements to reliability over time. We have undertaken analysis that shows this means that if current reliability levels are maintained there is an unacceptably high risk of non-compliance each year with the Reliability Standards in 2010/11 and beyond. To ensure compliance in future, EnergyAustralia has forecast a program of expenditure targeted to improve reliability to ensure we meet the mandated standards

			in future years. This is set out in Attachment 4.9 to our original submission. It should be noted that the Licence Conditions framework goes beyond the Schedule 2 Reliability Standards discussed in the EMRF submission. EnergyAustralia is obliged to comply with the Design Reliability Performance standards outlined in Schedule 1 which sets out network design input standards. We are also obliged to meet the requirements of the Schedule 3 Individual Feeder Standards. EnergyAustralia's reliability based capital program has been driven by compliance with all three schedules.
EMRF	26	“A supplementary issue is whether non- achievement of the service standards will result in a penalty anyway. In the absence of financial penalties (such as the AER decision not to apply despite recommendations from consumers) it is unlikely that the government can impose significant sanctions on DBs (they have never done so yet!) that fail to meet the licence conditions. This removes much of the risk faced by the DBs.”	It is incorrect to infer that EnergyAustralia has an option to fulfil its licence requirements. EnergyAustralia is under mandated licence requirements and must meet its obligations. Further, the Rules require that a DNSP’s building block proposal must include forecast of capital expenditure that is considers is required to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services. EnergyAustralia’s forecast capital program has been planned with these requirements in mind.
Replacement capex			
EMRF	6	“In addition to the expected demand growth, the DBs all pointed to the need to replace ageing assets. The AER draft decision has assumed that this is a key element within the reset yet analysis of the applications and the AER consultant’s reports highlight that 40-60% of the total capex budget is directed at growth projects, whilst a relatively smaller proportion is for replacement.”	EMRF’s statement is incorrect in relation to EnergyAustralia. Asset condition is a driver of more than 40 per cent of EnergyAustralia’s capital expenditure requirements for the next regulatory period. When expenditure to meet modern standards is added, this accounts for approximately 50% of the capital program. As mentioned above, EnergyAustralia’s growth driven capital accounts for less than 30% of the total program.
EMRF	26	“The capex programs include for an even greater rate of replacement raising the concern that assets still used and useful are being retired purely because the DBs will no longer receive a return on them as they have been fully depreciated.”	This is incorrect. EnergyAustralia outlined its methodology for determining its replacement capital expenditure requirements in section 4.2.2 of its June 2008 proposal. The process is grounded in condition assessments of network assets obtained through maintenance, on-going testing programs, or specific asset investigations. All network assets have been analysed using sophisticated analysis including:

			▪ Failure Mode, Effect and Critically Analysis, which is the tool used to examine how assets fail and what maintenance steps can be taken to avoid asset failure. ▪ Reliability Centred Maintenance, which directs maintenance to assets that have reached a certain age or time in service. RCM requires condition monitoring to ensure that maintenance is appropriately directed. Wilson Cook reviewed EnergyAustralia's policies and procedures. It noted that (Review of Proposed Expenditure, October 2008,Volume 2, p36): "We were satisfied that EnergyAustralia had followed reasonable policies and procedures that include the identification of need and the determination of least-cost solutions when making investment decisions. The level of expenditure (and its implicit timing) proposed by EnergyAustralia for the next period appears reasonable in that it demonstrates a consistent and rising trend that is matched to the company's understanding of the age and condition of its network and to the ability of the company to resource the substantial scope of works." It should be noted that this approach results in the presence on EnergyAustralia's system of significant numbers of assets over their "standard" lives. We also note that EnergyAustralia will be replacing significant quantities of underground cables which are not yet fully depreciated. More information on EnergyAustralia's approach for determining replacement capital expenditure requirements is set out in Attachment 4.8 to the June 2008 proposal.

Deliverability of capex			
EMRF	21	"In its assessment, Wilson Cook has only assessed whether the capex can be justified (which it confirms it can be, on both a needs basis and a cost basis), and has not assessed whether there is an ability to raise the cash needed for the works."	In our June 2008 proposal, EnergyAustralia identified a suite of delivery strategies to ensure the capital expenditure program is delivered. Wilson Cook reviewed the ability of EnergyAustralia to deliver the proposed capital program (Review of Proposed Expenditure, October 2008,Volume 2, p66) and found that: "EnergyAustralia has recognised the need to increase its resources to deliver its proposed investment programme and has taken measures to ensure that it is able to do so.' Further, Wilson Cook concluded that EnergyAustralia had proposed a reasonable implementation strategy and that they had no reason to suppose that EnergyAustralia will be unable to carry out its proposed program. The AER also reviewed the deliverability of the program and concluded that EnergyAustralia's plans to deliver the capital program were robust (p498 of AER's draft determination). Wilson Cook was not engaged to provide comments on EnergyAustralia's ability to raise capital needed to fund the investment program. Nevertheless, the EMRF is correct in highlighting that financing decisions are made more complicated by additional challenges brought upon by the global financial crisis. We understand that the AER is investigating this issue further on behalf of EMRF and other stakeholders. EnergyAustralia is unaware of any current or pending matter or circumstance that may affect EnergyAustralia's ability to obtain finance for the deliverability of our proposed capital program. The issue of availability of finance should not be confused with the costs of obtaining funds over the period. In this regard we disagree with the AER's assumption that capital investment requirements can be hedged or
EMRF	28	"The risk of the DBs not getting the funds required for the capex programs is high… The government finance corporations (such as T-Corp in NSW) are being limited in their ability to borrow. Australian banks have had to be supported by the Federal government to protect their borrowings and overseas banks have indicated they will be reducing lending in Australia. As a result of these constraints, bank lending has been tightened."	

			borrowed within the averaging period used to set WACC parameters. The AER's assumption does not hold for EnergyAustralia practically or pragmatically given the size of the financing involved and the current market circumstances. Our original proposal recommended an earlier observation period for calculating the risk free rate to enable certainty in obtaining finance arrangements before and during the period. We note our dissatisfaction with the AER's rejection of our preferred averaging period set out in the original proposal. We have noted that the AER's preferred observation period for calculating the risk free rate will result in an estimate of the rate of return that is materially biased below that required of investors in a similar commercial business. In our revised proposal we have suggested an alternative period that addresses the AER's reasons for rejecting the original period. The revised period goes some way to minimising risk associated with the cost of obtaining finance over a longer period when compared to the AER's assumptions on the rate of return using its preferred averaging period. Irrespective of this separate issue, we have every intention and expectation of being able to obtain the necessary finance to fund the capital expenditure program. EMRF also question whether the mini-budget will impact on NSW DNSPs' ability to deliver the capital program. The AER concluded in its draft determination that (p498): "The AER has assessed this financing constraint against the proposed capex programs from 2009–10 to 2011–12, and is satisfied that this need not adversely impact on the deliverability of the program. The reduction in the borrowing program represents a relatively small proportion of the capex program and its impact may be offset by increased internal efficiencies in each of the businesses and or by a change in the timing of dividend payments to the to the shareholder."

			In respect of this issue, it is our understanding that the amounts in the mini-budget (announced prior to the release of the draft determination) relevant to NSW DNSPs and TransGrid were the NSW Government's own view at the time of the determination process plus some initiatives in regards to leasing (which is unlikely to apply to EnergyAustralia as it already undertakes leasing of some fleet and IT). We are not aware of any other decision to reduce EnergyAustralia's borrowing capacity and we have every intention of obtaining the necessary finance to meet our requirements in the usual manner.
EMRF	30	"Whilst in the long term the EMRF does accept that the work EA has included in its program is probably necessary, the EMRF queries whether it is essential that all this work is needed to be carried out in the next five years, and not over a longer period."	We note that our EnergyAustralia's system capital expenditure program has been forecast from a bottom up consideration of drivers of network expenditure over the next 5-20 years. This included analysis of future load growth, asset condition and risk, and assessments of compliance with existing modern infrastructure and reliability standards. All projects incorporated into the program can be linked to a specific driver. The program was reviewed for deliverability, and given its size, was smoothed as much as possible to the point at which further smoothing (deferral of projects beyond the period) would result in EnergyAustralia not complying with its obligations. We consider that the program is deliverable, and that failure to deliver it will result in unacceptable levels of risk for the network in terms of long term asset management. EnergyAustralia's capital proposal can therefore be seen to represent the limit to which the investment plans can be smoothed using project deferral while still achieving licence compliance and balancing operational risk. The capital smoothing process not only improved the deliverability of the capital program, it also smoothed the price outcomes for customers. We also noted in our June 2008 proposal (p9) that any reduction in replacement expenditure would not address the existing backlog and would allow the proportion of assets over technical design age to increase resulting in unacceptable risk in future periods.

			Following our June 2008 proposal, EnergyAustralia investigated the impact of lower peak demand forecasts on growth related capital expenditure requirements as part of its revised regulatory proposal. This has resulted in a deferral of projects, resulting in a reduction of forecast capital expenditure of $234 million from the original proposal. This represents a deferral of 10 per cent of growth related capital expenditure and further improves the delivery of the total capital program.
Equity raising costs			
Integral Energy Country Energy	9 3	Integral Energy's comments in Chapter 4 of Submission of 16 February 2009– "AER's cash flow modelling" Country Energy comments in Submission of 16 February 2009– "Equity Raising Costs in the PTRM"	EnergyAustralia notes the submissions of Integral Energy and Country Energy on the AER's cash flow modelling for calculating equity raising costs. We support and concur with Integral Energy and Country Energy's analysis that there is an inconsistency between the cash flow modelling used in the calculation of equity raising cost and the PTRM. This inconsistency relates to the assumption by the AER that a dividend payout ratio of 70% is consistent with a gamma of 0.5 specified in the Transitional Rules. We had highlighted this inconsistency in page 3 and attachment "I" of our Further Submission of 16 February 2009. Attachment "I" recommended that the correct dividend policy is one that ensure the full distribution of imputation credits. Our recommendation is consistent with one of the options recommended by Integral Energy which states that the dividend payments should be "the dividends necessary to fully distribute all imputations credits". We consider that the AER needs to review its dividend payment calculation to ensure consistency between its cash flow modelling and the PTRM. We also note that Integral Energy's submission provided further independent advice to support its view that a cash outflow to reflect the repayment of debt must also be included in the cash flow modelling. This is to ensure that the benchmark gearing assumption of 60% is maintained during the regulatory period. We had highlighted this required amendment to the cash flow modelling in

			our revised proposal of 14 January 2009 and incorporated it in our revised equity raising costs. In summary, we note the consistent views, supported by independent expert advice, expressed by the NSW businesses in relation to the cash flow modelling used for the calculation of equity raising costs. We submit that the AER should reconsider its cash flow modelling to ensure consistency with the underlying assumptions used in the calculation of revenue.
Issues relevant to Part I, Chapter 8 of EnergyAustralia's regulatory proposal (Rate of Return)			
Integral Energy	16	"While there are some imperfections with the AER's approach of taking the Bloomberg fair yield for BBB rated 8-year corporate bonds and adding the Bloomberg fair yield spread between A rated 8 and 10-year corporate bonds to derive a proxy 10-year BBB+ corporate bond yield, Integral Energy considers that the AER's methodology is not unreasonable for the purposes of determining the benchmark debt risk premium." "Integral Energy notes the proposals from other network businesses to use an average of the annualised BBB+ debt risk premium rates derived from the Bloomberg and CBA Spectrum. Recognising that greater statistical confidence may be achieved from increasing the number of data points, Integral Energy submits that the use of an average of the two services may reduce errors in measuring the DRP and should be fully considered by the AER."	EnergyAustralia supports Integral's submission that "greater statistical confidence may be achieved from increasing the number of data points" and the approach proposed in EnergyAustralia's revised proposal "may reduce errors in measuring DRP and should be fully considered by the AER". This contrasts with what Integral Energy believe are imperfections with the AER approach of relying on Bloomberg alone. It is difficult therefore to reconcile these statements with Integral's conclusion that the AER's methodology (to solely rely on Bloomberg) is not unreasonable. We can only assume that Integral prefers a hybrid approach but that it considers the AER's methodology is not unreasonable. EnergyAustralia does not agree with Integral's view. In the current market conditions, the AER should not rely solely on Bloomberg data to determine the debt risk premium. As at December 2008, CBASpectrum observations is estimate yields on BBB+ bonds to be 1.55 per cent higher than what Bloomberg is estimating for riskier BBB bonds. This is despite the two data sources rarely deviating more than 0.5 per cent in the past. In our revised proposal we noted that evidence suggests that neither Bloomberg or CBASpectrum data is likely to provide a reliable estimate of corporate bond yields. EnergyAustralia's view is that an appropriate approach to address the issue is to use an averaging approach to smooth the data observations. This is consistent with the views of our expert, CEG. EnergyAustralia also noted that the AER's previous conclusions regarding

			the consistency of Bloomberg data over CBASpectrum data need to be reviewed in light of new information. CBASpectrum has altered its methodology since the AER undertook its review of corporate bond yields. We also highlighted that the ESCV recently found that CBA spectrum performed better in predicting bond yields under current market conditions. Further, there is no evidence to suggest that the AER revisited this issue following the onset of the global financial crisis and therefore our issues regarding the usefulness of Bloomberg in current circumstances must be addressed. We note Bob Officer's report, attached to our Further Submission of February 2009 and his comments that it is not appropriate to use observations on corporate debt in markets are thinly traded. Officer suggests that some subjectivity is involved. However, given traditional observations are likely to substantially underestimate the true cost of company debt, the choice of the rate that results in the lowest outcome is not appropriate. Further, the AER's preference for one methodology over another is probably irrelevant given that under the rules, it can only move away from EnergyAustralia's methodology set out in its revised proposal to the extent necessary to enable the methodology to be approved in accordance with the Rules , which in this case are non prescriptive.
Issues relevant to Part I, Chapters 9-11 of EnergyAustralia's regulatory proposal (Operating Expenditure)			
EUAA	18	"Wage growth is a significant part of the opex for the DNSPs. Since the worsening economic climate wage cost pressures have fallen. As a result, the Reserve Bank of Australia has revised its Wage Price Index for 2009-10 to 3.5% down from 4% in 2008-09 and expects this index to remain static at 4% for 2010-11 to 2011-12. The RBA now supports an easing in current and expected labour costs from business as wage pressures have eased in the economy."	EnergyAustralia's revised regulatory proposal includes updated labour cost escalators which take into account up to date information on the economic outlook. Specifically, EnergyAustralia applied KPMG Econtech's labour cost forecasts consistent with the AER's proposed method. In our revised proposal, we requested that the AER consult with businesses as soon as updated Econtech forecasts become available.

EUAA	14	"Operating costs appear to lack any substantial benchmarking and meaningful efficiency and productivity improvements which is a standard business practice for businesses operating outside of economic regulation."	Chapter 11 of EnergyAustralia's June 2008 proposal outlines a report prepared by SAHA and their benchmarking study of maintenance and other operating costs among Australian DNSPs. Our revised proposal and interim submission of January 2009 included analysis from Huegin consulting which provided important analysis and critique of Wilson Cooks benchmarking analysis used by the AER. This included the development of additional benchmarking tools which support EnergyAustralia's operating expenditure forecasts (while still noting the limitations of benchmarking). We therefore disagree with EUAA's comment that there is a lack of benchmarking in this process. However, EnergyAustralia noted in its June 2008 proposal that benchmarking has inherent limitations. In this regard, we note NERA's advice (which we provided at attachment 6.1 of the June 2008 proposal) which confirmed that little can be said about the relative efficiency of the business once all of the characteristics of each DNSP's business and operating environments are considered. Further, benchmarking assumes that the costs of other comparator businesses are forecast accurately. EnergyAustralia incorporated efficiency and productivity improvements in its capital and operating expenditure forecasts for the next regulatory period. We noted some of these initiatives in section 9.2.4 of the revised regulatory proposal including: ▪ Design initiatives introduced into projects over the last 2 years and estimated to have saved approximately 5 per cent of project life cycle costs. ▪ Use of an enhanced suite of contracting arrangements with external partners which will free up internal resources and allow EnergyAustralia to deliver more with the existing employee base. ▪ Design and construct style contracts, which also enable a streamlined delivery of the investment program. ▪ Investment in IT and property (depots etc) that will improve staff capability.

EMRF	36 42	"… (one of the) fundamental issues that arise from the Wilson Cook analysis … to what extent is the composite measure applicable when there is such large diversity between the different DBs and to what extent are the weightings realistic or even applicable." "Unfortunately this (Wilson Cook) benchmarking approach has indicated some limitations."	EnergyAustralia agrees with the EMRF's comments regarding the methodological weaknesses underlying Wilson Cook's customer size variable (CSV) benchmark analysis. In our revised proposal we noted that Wilson Cook's CSV: ▪ Failed to consider and make variations for the network type, age, cost allocation and accounting policies of the businesses. ▪ Adjusted the regression line to overcome anomalies in the uncorrected regression analysis, without considering the implications of such modifications. ▪ Modified the variables in the model based on 'intuition' and without any evidence or analysis as to whether its modifications were appropriate. Despite these deficiencies, Wilson Cook appears to have drawn definitive conclusions from this analysis. EnergyAustralia's revised proposal and interim submission provides a more detailed analysis of the deficiencies with Wilson Cook's CSV benchmark analysis (section 9.2.2).
EMRF	38	"Opex does not increase proportionally with demand, consumption or numbers of consumers. There are many aspects of opex that are fixed and do not relate to these parameters. For example, the costs controlling the network are essentially fixed and the computer systems mange the increased numbers of plant items without the need to increase staffing."	EnergyAustralia broadly accepts this comment. Our operating expenditure forecast process applies appropriate workload escalators to each cost activity. In doing so, EnergyAustralia only applied workload escalators to the variable costs of each cost activity. However, the degree to which a company's operating costs remain relatively fixed is dependant on changes to the scale and scope of the services it provides. This is one reason why EnergyAustralia found it necessary to introduce step changes in operating costs which reflect a change in the scale or scope of operations. Section 6.2.2 of document "Operating Expenditure Forecasting, May 2008" (which was attached as supporting documentation to the June 2008 proposal) provided more details on the workload escalators used by EnergyAustralia. This includes the workload drivers allocated to each activity, the related variable component of costs and the rationale for the allocation.

EMRF	6	"The EMRF further considers that replacement projects should have the impact of reducing opex, but even the modest asset replacement programs proposed by the DBs have not resulted in the AER reducing opex to the extent expected, as the AER is even proposing an increase in opex overall."	EnergyAustralia recognised that there is a relationship between maintenance costs and replacement of assets. We explicitly modelled this relationship when determining forecast maintenance requirements for the next regulatory period. This relationship also takes into account investment on replacing assets in the current period. It is important to note replacement of key assets has the effect of reducing forecast maintenance costs during the period in some asset classes. However, for classes where less replacement is planned (i.e. distribution mains and distribution substations) maintenance costs are forecast to rise to reflect the higher costs of managing an asset base that continues to age. The relationship between age, condition and maintenance costs is described in section 9.6 of the June 2008 proposal.
EMRF	40	"There is no clear reason why the opex should grow at such a rate over the next period, especially as there has been so much capex in the current period and even more planned for the next period."	The EMRF's comments imply that EnergyAustralia's large capital expenditure program will lead to *reduced* operating expenditure. It is unclear how the EMRF formed this view. It is clear that a large investment program will result in increased operating expenditure as the business and the network increases in size. This can be demonstrated by examining EnergyAustralia's capital expenditure categories. As noted above, replacement expenditure has a direct impact on maintenance operation costs and has been directly modelled to determine the total forecast of operating expenditure. Forecast capital expenditure on augmentations to the distribution network will result in increased maintenance, network operating and business support costs. Similarly, capital expenditure driven by compliance with new obligations and licence requirements will result in increased operating costs. While EnergyAustralia notes that the increase in operating expenditure does not increase in line with the capital expenditure program, we do not understand how operating expenditure can be maintained as existing levels if the size of the network increases. With respect to investment on non-system assets such as IT and property, EnergyAustralia notes that its forecast processes identify cost savings offsets

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<td>from the introduction of new technology, for example, the retirement of old technology and the consolidation and better location of depots and offices. Our revised proposal (section 9.2.4) and further submission (p8-9) provide additional evidence from economic experts to demonstrate that large scale investments in IT do not lead to significant short term operating efficiencies but rather increase the capability of systems and better integrate data to allow better investment decisions to be made.

Our revised proposal (section 9.2.4) and further submission (p8-9) provide additional evidence from economic experts to demonstrate that large scale investments in IT do not lead to significant short term operating efficiencies.</td>
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<td colspan="4">Issues relevant to Part I, Chapter 13 of EnergyAustralia's regulatory proposal (X-factors)</td>
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<td>EMRF</td>
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<td>"Thus the AER must have regard to the reasonableness of the prices consumers have to pay as an essential element of its assessment. Allowing largely unfettered price rises which result in loss of usage has minimal impact on the DB, but a significant impact on the consumers continuing to use the service."</td>
<td rowspan="2">EnergyAustralia's proposed price path for direct control services is set out in the table below.

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<tr><th></th><th>FY10</th><th>FY11</th><th>FY12</th><th>FY13</th><th>FY14</th></tr>
<tr><td>Distribution Price</td><td>-39.29</td><td>-14.29</td><td>-14.29</td><td>-14.29</td><td>-14.29</td></tr>
<tr><td>Transmission Price</td><td>-17.08</td><td>-15.43</td><td>-15.43</td><td>-15.43</td><td>-15.43</td></tr>
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EnergyAustralia is aware that an increase in network electricity prices will</td>
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<td>Anglicare</td>
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<td>"Energy price rises will disadvantage already struggling low income households. Compensatory measures should include special one-off assistance to such households…"</td>
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PIAC	2	"If implemented, the EnergyAustralia revised proposal would require an increase in household network charges above 170% by the end of the regulatory period. Based upon figure 2.1 in Part III of the EnergyAustralia revised submission and using the average Sydney electricity consumption for a one to two person household for 2006 given by IPART, this would see an average cost increase in excess of $500 for this class of customer. With this customer class tending towards lower than average electricity use and this figure being an average, it is reasonable to anticipate deviations higher than this for most households."	impact consumers of electricity, particularly disadvantaged customers. EnergyAustralia actively supports measures aimed at minimising the impact of our price increases on electricity bills for low income households. EnergyAustralia's retail business is investing more than $3.5 million on a program to help customers who are having long term difficulty paying their electricity bills. Our retail business has provided funding to groups to offer No Interest Loans on essential energy efficient appliances. We are also offering energy efficiency advice, energy audits and installations and regular repayment options on bills. Our network and retail business has been at the forefront of interval and smart meters technology in homes and businesses and tariff design that helps give customers more control over their electricity bills. Applying new technology and innovative tariffs gives customers the control to switch some of their non essential electricity use to times when electricity is cheaper – less than half the normal rates at some times. On our analysis of people using this new technology, about 69% of the customers are paying the same or less with their smart meter compared to the standard rate (of their combined network and retail bill). In fact on average these customers are saving about $64 a year on their electricity bills. Our retail business has also ramped up our energy efficiency campaigns to help our customers find more ways to use less energy without impacting on their lifestyles. We have helped customers by giving away more than three million light bulbs, collecting more than 1200 old second hand fridges, giving away 500,000 shower timers, providing rebates for energy efficient hot water systems. Over the past 12 months alone we have visited more than 10,000 homes to fit them out with energy efficient light bulbs and energy and water saving shower heads. While we are concerned about the impacts of higher prices on our customers, we note that our proposed price increase is necessary to recover

			the efficient costs of providing regulated network services. Lower prices will not provide customers with a secure, safe and reliable supply of energy and will result in even higher prices in future periods. Further, the economic costs of under-investing in the network are high and would have long term implications for the economy. EnergyAustralia notes that the underlying drivers of its costs for the next regulatory period include: ▪ A large proportion of EnergyAustralia's network was built between 1965 and 1980 and its age is therefore approaching or above 40 years old. This requires significant investment in renewing the network. If EnergyAustralia does not undertake this investment, there would be unacceptable risk in future periods. ▪ There is a disconnect between energy consumption and summer peak demand growth, which requires EnergyAustralia to undertake significant network investment to meet demand at peak times. ▪ EnergyAustralia is required to comply with new design and reliability planning licence requirements and must undertake investment to meet these requirements. As noted earlier, the deteriorating economic conditions have not significantly affected the underlying drivers of our costs. EnergyAustralia however has considered the impacts of lower economic growth on peak demand and has deferred over 10 per cent of expenditure on growth related capital expenditure. In undertaking such a review, we have sought to reduce price pressures for customers to the full extent possible while still meeting our regulatory obligations to provide a safe, secure and reliable energy service. Stakeholders also need to recognise that the initial price increase for customers is a legacy of previous regulatory decisions. Prices over the last ten years have not kept pace with EnergyAustralia's capital and operating

			expenditure requirements. For instance, at the beginning of this process the average real price paid by EnergyAustralia's customers for the use of our network was lower than it was 10 years previously despite a significant increase in capital requirements over the period. EnergyAustralia estimates that a price adjustment of 18.6 per cent is necessary to rectify the legacy of previous regulatory decisions. This is before future costs are taken into account. In particular, we note that regulators have historically set an allowance for asset replacement below what EnergyAustralia proposed and have failed to understand the need for sustainable renewal programs. Network prices have therefore been historically set at unsustainably low levels.
Issues relevant to Chapter 14 of EnergyAustralia's regulatory proposal (Incentive mechanisms)			
TEC	2	"The innovation allowance should be set at 5% of the projected network capital expenditure for each DNSP – the amounts set are far too low to promote the utilisation of the vast amount of DM available."	We support stakeholder concerns surrounding the "modesty" of the innovation allowance. In previous submissions we have proposed what we believed was a modest allowance representing 0.5-1% of revenues ($10-$20 million per annum). Our concern remains that the existing allowance of $1 million per annum, while higher than what the AER has previously opposed is still too low to derive any meaningful conclusion on the success of DM innovation initiatives. An allowance of $10 million per annum would be an ambitious target, but is therefore an appropriate incentive to apply (particularly as the scheme has an ex-post adjustment for unused revenues). The cost of this type of scheme with a higher cap to the average customer would be in the range of $2.50 to $3.00 per year (or up to 6 cents a week). We believe such a cost is justifiable in the context of submissions raised in respect of DM.
City of Sydney	7	"The City of Sydney supports the AER's introduction of a DMIA. However, at a stipulated maximum level of only $1 million per annum, or roughly 0.06% of EnergyAustralia's annual revenue allowance, this is unlikely to make any discernable difference to EnergyAustralia's investment plans or peak load growth.	

EUAA	6	"However, under the DBs' proposals, DM will continue to remain not much more than a token gesture during the 2009/2014 regulatory period."	EnergyAustralia is an industry leader with respect to DM and has an extensive track record of implementing DM projects. Our capital governance processes are grounded in prudent consideration of DM opportunities. For instance, EnergyAustralia investigates DM opportunities for material growth related projects through a screening study and DM investigation. EnergyAustralia implements DM projects that are feasible and economically efficient. Section 6.7.2 of EnergyAustralia's June 2008 proposal outlines the method by which EnergyAustralia forecast DM in its forecasts of capital and operating expenditure. This involved deferring investments related to demand growth through tariff based DM and project specific DM. Further information on this method can be found at Attachment 5.13 of the June 2008 proposal. EnergyAustralia notes that our revised proposal removes the impact of tariff based DM. EnergyAustralia was required to remove the impact to address the AER's decision regarding the assignment of customers to tariff classes. This is further discussed in this response to stakeholder concerns in the section relating to issues on assigning customers to tariff classes.
TEC	5	"The AER makes a curious statement in the Draft decision that, "the AER understands that there are a number of demand-side aggregators operating in NSW." (p. 267) TEC conversely understands that there are very few indeed (certainly less than five)."	EnergyAustralia agrees with TEC's comments that there are limited DM aggregators operating in NSW. This is consistent with EnergyAustralia's general experience of limited scope for effective network DM relative to the overall requirement for growth capital.

Integral Energy	25	"Integral Energy also seeks clarification of the following three matters: 1. … Integral Energy assumes that the audited data referred to (in the DMIA) is for the weighted average price cap. Integral Energy seeks confirmation that this is the case. 2. … Integral Energy is considering implementation of direct load control programs which will require installation of equipment on customers' premises and appliances and will have a tariff component associated with them. It is not clear from the AER's statement whether these programs would be classified as tariff based or non-tariff based programs. Integral Energy seeks clarification from the AER on this issue. 3. At the end of the paragraph at the top of page 9 of the replacement DMIA the AER have stated that it will not allow a DNSP to recoup foregone revenues resulting from demand management carried out independently of the DMIA. Integral Energy assumes that this means that the AER will not allow recovery of foregone revenue through the DMIA for programs outside the DMIA. If this is not the case then recovery of foregone revenue through the D factor would be prohibited. Integral Energy seeks confirmation that its assumption is correct."	EnergyAustralia also seeks clarification on these issues.

PIAC	4	"PIAC questions why the DNSPs are able to reclaim funds spent above the regulatory allowance in a regulatory period, in the following regulatory period. Firstly, this suggests that the previous regulators decision was not binding and expresses a lack of faith in that regulator. Secondly, this provides no incentive for the DNSPs to stick to the NSW distribution determination for 2009-10 to 2013-14, in the knowledge that they will be able to reclaim the over-spend in the following regulatory period. This has the effect of undermining the regulatory process entirely."	PIAC appear to have not fully understood the capex incentive framework and the penalties faced by regulated businesses from over-spending the capital allowance. Under the ex-ante capital incentive, businesses are unable to recover the costs of investment in a regulatory period if the investment exceeds the allowance set by the regulator. EnergyAustralia overspent its capital expenditure allowance set by IPART (distribution) and the ACCC (transmission) by 440 $million (nominal). Consequently under the ex-ante incentive framework, EnergyAustralia was unable to recover its efficient costs of investment during the 2009-14 period. A significant driver of the over-spend was to replace aged assets ($357 million overspend). This was in part due to IPART and the ACCC setting an insufficient replacement capital allowance (below what EnergyAustralia had proposed in its 2004 proposals). Section 6.2.2 of EnergyAustralia's June 2008 proposal provides more information on the drivers of EnergyAustralia's investment over-spend in the period It should be noted that the AER's draft decision adopts a high powered incentive framework which penalises (more than a low powered incentive) if EnergyAustralia overspends its capital allowance in the period.

Issues relevant to Part I, Chapter 15 of EnergyAustralia's regulatory proposal (Pass Through)			
EMRF	7	"The EUAA has significant reservations about the AER's proposal to allow pass through for Retail Events related to possible privatization of NSW electricity retail businesses and their separation from the DNSPs. These should be paid for out of the proceeds of any privatization not by end users through distribution charges."	EnergyAustralia does not agree with the EMRF that the costs of privatisation should be borne by shareholders. We note the AER's draft determination accepted the pass through event. The AER noted that the costs of providing direct control services may increase due to loss of synergies. We note the AER's draft determination accepted the pass through event. EnergyAustralia considers it is highly inappropriate for shareholders to share the burden of higher costs associated with loss of synergies between the businesses. The Rules define a positive pass through event for a Distribution Network Service Provider as an event that materially increases the costs of providing direct control services, which are network related costs only.
City of Sydney	9	"Given that large scale embedded tri-generation facilities installed in strategic locations have the potential to offset the growth related components of network investment, there is a highly sophisticated avoided cost contributing to he business case for demand management."	EnergyAustralia is already working with the City of Sydney in progressing its goals of a secure, high quality, and energy efficient supply of electricity for Sydney CBD. We note that the submission raises a number of high level policy issues concerning the connection of embedded generation to distribution networks. It is important that these issues are progressed through the policy reform work currently being undertaken by the MCE and AEMC. While we are keen to work with the Council using the expertise of our staff on connection issues, we note that EnergyAustralia must undertake investment in the next regulatory period to meet its reliability obligations to provide a reliable energy supply to the Sydney CBD. Currently we have only one committed embedded generation project in the CBD area (of less than 1MW of capacity). We also note that our experience with connecting embedded generators is that such proponents generally require back-up from the distribution network. The City of Sydney's plans for tri-generation is a further example of why EnergyAustralia considers that the AER should accept our proposed customer connection pass through event. The costs associated with these possible types of connection events are outside EnergyAustralia's control,

			are highly uncertain and could not reasonably have been included in EnergyAustralia's forecast of required capital expenditure.
Issues relevant to Part II, Chapter 3 of EnergyAustralia's regulatory proposal (Negotiable components of direct control services)			
Integral Energy	22	"On reviewing the concerns raised by EnergyAustralia, Integral Energy is of the view that there would be merit in amending the proposed classification to address a number the issues raised by EnergyAustralia including their contention that the third limb of the definition is extremely broad and capable of capturing or impacting upon just about every aspect of the connection service… Integral Energy believes that the above dot point should be amended to make it clear that the only components of the connection service that are negotiable are those not covered by other regulatory instruments such as IPART's Capital Contributions Determination and the AER's monopoly service arrangements. The amendment to the third limb of the definition will reduce any confusion that may arise between the negotiable components framework and the regulatory instruments and would allow the provision of documents and information to prospective connection customers that would enable them to understand what is negotiable and what is not."	EnergyAustralia supports Integral Energy's decision to move away from the AER's proposed definition of negotiable components of direct control services. Integral wishes to make it clear that "the only components of the connection service that are negotiable are those not covered by other regulatory instruments such as IPART's capital contributions determination and the AER's monopoly services arrangements." We accept the arguments raised by Integral in respect of the third limb of the definition but do not accept that the problem is limited to connection services. Our revised proposal and interim submission highlights ambiguities surrounding the use and application of the first two limbs which also requires clarification. In addition, our revised proposal and interim submission notes that the proposed definition falls short of what EnergyAustralia considers is required in the definition. We note that Integral's issue would be catered for within the definition proposed by EnergyAustralia.
Issues relevant to Part II, Chapter 4 of EnergyAustralia's regulatory proposal (Control mechanisms)			
Integral Energy	19 20	"to manage volume risk, Integral Energy supports the proposal by EnergyAustralia for the inclusion of a G factor adjustment to the WAPC formula, with some minor modifications... Integral Energy proposes that the G factor should not be linked to overall revenues (i.e. a revenue cap); rather it should be limited to outturn volume	We would welcome any further information Integral Energy has on its proposal for a volume adjusted G factor arrangement. EnergyAustralia considered this option when developing its G factor arrangement. However, on balance it found an adjustment based on revenue to be more transparent and palatable in addressing the problem of inherent uncertainty in volume forecasts. We would nevertheless welcome more information on how a "volume

		changes relative to the forecasts underpinning the final determination. Integral Energy notes that volume variations will have a revenue impact; however this is distinct from a revenue cap in that all other elements of Integral Energy's network revenue would not be impacted by the G factor."	variance" is adjusted within the price mechanism that will apply. We are unsure how Integral intends this to work mathematically compared to the approach we have applied. Our only additional comment without further information on the approach relates to the disconnect between revenue outcomes possible under a WAPC and variances between forecast and outturn volumes. EnergyAustralia's G factor was a deliberate attempt to remove any windfall revenue gain or loss associated with outturn volumes being different to forecast. There may be instances where revenue outcomes are relatively aligned despite considerable variation between forecast and outturn volumes. A volume related adjustment therefore has the potential to accentuate the gain or loss depending on the circumstances. Integral's submission, which prefers an adjustment based on outturn volume rather than revenue, might be construed as asserting that the application of the G factor would change the form of control mechanism away from a weighted average price cap. For the reasons explained in our revised proposal this is not the case. The control mechanism is substantially the same as that which the AER applied in the draft determination. However there is an adjustment to the control mechanism in a future year in circumstances where there is an abnormal change in out-turn revenues. If there is no abnormal change in outturn revenues the WAPC operates exactly the same.
Integral Energy	21	"Integral Energy considers that an appropriate value of L is between 2% to 5%, representing a band of +/- approximately $16-40 million (in 2009/10) that would be in place to allow volumes to increase or decrease within the WAPC without adjustment before the G factor would act to adjust average network prices (positively or negatively) in the following year."	EnergyAustralia supports Integrals submission which identifies an appropriate range of between 2-5% for the *L.*

PIAC	3	"It is acknowledged that there is currently much uncertainty about how these policies will be finalised, and therefore PIAC recommends that the pricing determinations and associated demand forecasts be re-opened at a later date when more information is available."	EnergyAustralia notes that a reopening mechanism is not available to the AER under the existing rules framework.
Integral Energy	24	"These reasonable estimates are used in the annual WAPC calculation. As noted … Integral Energy has detailed its concerns in relation to the reasonable estimates calculation and the restriction this would place on Integral Energy's ability to introduce innovative time of use energy tariffs and demand tariff structures."	EnergyAustralia's supports Integral's view on this issue. We note that our submission on the AER's draft determination for other DNSP and TNSPs also raised our concerns with reasonable estimates used in the WAPC calculation (p7).
Issues relevant to Part II, Chapter 7 of EnergyAustralia's regulatory proposal (Alternative Control Services)			
SSORC	1	Furthermore, as a monopoly service, there should be absolute transparency on the costing models. EnergyAustralia's claim of commercial-in-confidence issues involved in the relationship with Councils are not credible, and serve only to obscure adequate analysis of a monopoly service.	EnergyAustralia has provided cost to serve models to the AER for 41 public lighting customers. EnergyAustralia is not able to provide the full model to any one council or its consultant because it contains confidential information (primarily relating to public lighting inventories, total costs, rebates and existing cross subsidies) applicable to other councils and other public lighting customers.
SSORC	2	During the pricing review process EnergyAustralia has repeatedly declined to substantiate the basis of large proposed increases and anomalies in public lighting pricing.	EnergyAustralia has provided detailed commentary on its pricing methodology in its June 2008 proposal and January 2009 revised proposal. Significant price rises have been required in order to achieve cost reflectivity for the public lighting services provided.
SSORC	3	EnergyAustralia continues to refuse to disclose underlying modelling and cost information to its captive street lighting customers.	EnergyAustralia's public lighting customers are not captive. They are free to tender for public lighting services from another operator. EnergyAustralia's public proposals provided detailed information on the price modelling method. The public pricing spreadsheets contain capital and operating costs for every item of inventory that is in that customer's district.

SSORC	3	It is now a very late stage in the review process, and EnergyAustralia continues to demur. In this monopoly arrangement, EnergyAustralia's approach is apparently to withhold adequate information from customers about the underlying cost of the service.	EnergyAustralia does not have a monopoly arrangement for the provision of public lighting services. Councils are free to tender for the public lighting services that they receive. EnergyAustralia has provided cost to serve information in the pricing models that are available for the 41 local councils. EnergyAustralia continues to respond to all information asked for by the AER in respect of public lighting. In some respects the level of scrutiny involved in the information requests surpasses the level of scrutiny involved in other (supposedly more heavy handed) regulated services. We will continue to co-operate with the AER in respect of the information it requests.
SSORC	3	In Section 17.6.8 of its Draft Determination, the AER states that EnergyAustralia has provided *"…a scaled down version of the cost-to-serve model for each council".* In fact, however, the information provided by EnergyAustralia is so 'scaled down' as to provide no meaningful cost-to-serve information.	This is not the case. The "Component Costs by Customer" worksheet in each of these models provides capital and operating costs for each component that is located in the customer's district. It also shows the component count for each item. A customer is able to see which components make up the largest (and smallest) proportion of their public lighting bill.
SSORC	4	The average age of existing assets may well be older than the estimated half life of public lighting assets.	EnergyAustralia has not used a half life to value public lighting assets. The annuity method (for new installs) does not assume that an asset is half way through its life. The AER's limited building block method (for existing stock) also does not use a half life assumption.
SSORC	8	We note however, continuing concern about EnergyAustralia's approach to the valuation of its assets in the event of a retrofit requested by Council before an asset has reached the end of its working life or in the case that a Council wishes to exit arrangements altogether regarding existing assets.	EnergyAustralia revised its method for calculating the rate 4 retrofit rate in the January 2009 submission. The residual is based on a component capital value that is depreciated by 75%. EnergyAustralia has included this residual amount in its retrofit rate so that it can recover the lost asset value of the replaced component.

SSORC	8	It is also unclear why, if Councils agree to pay for the residual condition based capital charge on the asset being replaced before the end of its useful life, they would also be liable for a higher on-going tariff for the new asset (eg under Tariff class 6).than would otherwise by the case (eg under Tariff class 3 or 5).	Under the principle of cost reflectivity, EnergyAustralia is of the view that if a public lighting customer requires a new component, then it should be charged a price that reflects the cost of that component and associated service.
Issues relevant to Part III, Chapter 1 of EnergyAustralia's regulatory proposal (Assigning Customers to Tariff Classes)			
City of Sydney	13	"Another barrier relates to the AER's apparently restrictive guidelines for reassigning customers to tariff classes… it is not clear why the AER would wish to obstruct the movement of customers from fixed rate tariffs to time of use tariffs to time of use tariffs, particularly when customers volunteer to switch over.'	EnergyAustralia supports this statement.
Integral Energy	23	If, during the 2009 regulatory control period, Integral Energy were to change its policy on new and replacement meters and install time of use meters in all instances, then the process in Appendix A of the draft decision would not permit the customers to be re-assigned to a time of use tariff as there has been no change to their load or connection characteristics. Integral Energy therefore recommends that the AER modify its wording in section 5 of Appendix A of the draft decision so that a change in connection characteristics specifically includes the installation of a meter with time of use capabilities in order to enable the re-assignment of the customer to a time of use tariff."	EnergyAustralia outlined its concerns with the AER's proposed procedures for tariff assignment in Chapter 1 of Part III of its revised proposal and interim submission (January 2009). Fundamental to those concerns was that the AER's procedures would restrict EnergyAustralia's ability to assign customers to time of use meters. Integral has suggested that this could be addressed by the AER specifying that installation of a time of use meter is a change in connection characteristics. EnergyAustralia supports the intent of Integral's suggestion and agrees that meter type must be recognised as a characteristic which is relevant to tariff assignment. Whilst generally metering is not regarded as part of a customers physical connection, if a broader view is taken of "connection characteristics" then Integral's suggested approach would work as would our suggestion of including metering as a separate characteristic.

Integral Energy	24	"Integral Energy is also concerned that under the draft procedures the AER becomes the dispute resolution body for any dispute arising from a re-assignment of customers. As the majority of customers would be "small" customers, that is, customers consuming less than 160MWh per annum, they would be covered by the NSW Energy and Water Ombudsman. Integral Energy believes that this would be the more appropriate body for referral of any disputes."	In its revised proposal and interim submission, EnergyAustralia notes its dissatisfaction with the dispute resolution procedures advocated by the AER in the draft determination. We note that dispute resolution powers outlined in Part 10 of the NEL are appropriate for any dispute of this type. However we accept Integral's comment that to the extent that customers have redress through an industry the ombudsman then that that is the procedure through which disputes regarding tariff assignment should be managed.
Integral Energy	24	"Integral Energy suggests that section 12 of Appendix A of the draft decision be revised such that if the AER does not make a decision within 30 business days of receiving a relevant request, then the re-assignment proceeds to ensure that there are no unintended barriers to the introduction of innovative tariff and metering options."	EnergyAustralia supports this and noted in its revised proposal that the determination supports a presumption that the DNSP is entitled to change customer tariffs if it can demonstrate that it complied with approved procedures.
Issues relevant to Part III, Chapter 2 of EnergyAustralia's regulatory proposal (TUOS recovery)			
Country Energy	2	"It appears to Country Energy that the TUOS recovery treatment will be set back by one year by using the actual audited balance of year (t-2) rather than the forecast balance of year (t-1). This lag of one year may result in greater fluctuations in TUOS between years, an undesirable outcome for customers who seek stability and predictability in prices to the greatest extent possible. Country Energy would be happy to discuss this matter further with the AER prior to confirmation of the methodology in the final decision".	EnergyAustralia supports Country Energy on this issue. We raised this issue in our June 2008 proposal and revised proposal.