Draft Decision

NSW and ACT Transmission Network Revenue Caps – EnergyAustralia 2004/05-2008/09

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Commissioners:
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Contents

Glossary

ACCC	Australian Competition and Consumer Commission
ACG	Allen Consulting Group
ACT	Australian Capital Territory
AER	Australian Energy Regulator
AGSM	Australian Graduate School of Management
AR	allowed revenue
capex	capital expenditure
CAPM	capital asset pricing model
code	National Electricity Code
CPI	Consumer Price Index
customers' group	Refers to the joint submission from Australian Business Ltd, Australian Consumers Association, Energy Action Group, Energy Users Association of Australia, and National Farmers Federation.
DRP	Statement of Principles for the Regulation of Transmission Revenues – Draft
EMRF	Energy Markets Reform Forum
ERAA	Energy Retailers Association of Australia Incorporated
ESC	Essential Services Commission of Victoria
FRC	full retail contestability
GasNet	GasNet Australia (Operations) Pty Ltd
GHD	GHD Pty Ltd
GWh	gigawatt hour
IDC	interest during construction
IPART	Independent Pricing and Regulatory Tribunal of New South Wales
kV	kilovolt
MAR	maximum allowed revenue

MRP	market risk premium
MW	megawatt
NECA	National Electricity Code Administrator
NECG	Network Economics Consulting Group
NEM	National Electricity Market
NERA	National Economic Research Associates
NPV	net present value
NSW	New South Wales
OCA	Olympic Co-ordination Authority
ODRC	optimised depreciated replacement cost
OH&S	occupational health and safety
Opex	operating and maintenance expenditure
PTRM	post tax revenue model
QCA	Queensland Competition Authority
RAB	regulatory asset base
RCM	reliability centred maintenance
SKM	Sinclair Knight Merz Pty Ltd
TNSP	transmission network service provider
Tribunal	Australian Competition Tribunal
TUOS	transmission use of system
VM	value management
WACC	weighted average cost of capital

1. Executive summary

1.1 Introduction

EnergyAustralia owns and operates a part of the electricity transmission network in New South Wales (NSW). EnergyAustralia also owns and operates an electricity distribution network in NSW. Currently EnergyAustralia's distribution network is regulated by the Independent Pricing and Regulatory Tribunal of NSW (IPART), and the transmission network is regulated by the Australian Competition and Consumer Commission (ACCC).

On 23 September 2003, EnergyAustralia lodged an application for a revenue cap with the ACCC in respect of its transmission network for the period 1 July 2004 - 30 June 2009.

The ACCC seeks submissions from interested parties on this draft decision. The closing date for submissions is 27 August 2004.

Should any interested party request that a public forum be held on this draft decision, this will be held before the end of August 2004.

A copy of EnergyAustralia's application, additional information, GHD Pty Ltd's (GHD) report and submissions are available on the ACCC's website.[1]

1.2 Opening asset base

In its application, EnergyAustralia proposed an opening regulatory asset base (RAB) of $702 million, but subsequently revised this to $680.2 million. Both figures are based on an optimised depreciated replacement cost (ODRC) valuation conducted by Sinclair Knight Merz (SKM). EnergyAustralia contends that a new ODRC valuation is warranted because the 1999 valuation contains material errors.

EnergyAustralia also states that all of its past capital expenditure (capex) is prudent and should be included in the opening RAB.

The ACCC considers that EnergyAustralia has failed to demonstrate that the ODRC valuation conducted in 1999 is materially affected by error. Further, the ACCC is unable to determine whether EnergyAustralia's past capex is efficient and does not accept the values included in EnergyAustralia's proposed 2004 ODRC valuation.

Therefore, the ACCC proposes to adopt a roll-forward methodology in determining an opening RAB for the 2004-2009 regulatory period.

[1] www.accc.gov.au

With regard to assets changing classification from distribution to transmission from 1 July 2004, the ACCC's draft decision is that these assets now meet the National Electricity Code (code) definition of transmission assets and the transmission opening RAB will be increased by $90.4 million, with a corresponding reduction in the distribution RAB.

In assessing EnergyAustralia's past capex, the ACCC sought information from EnergyAustralia to demonstrate the efficiency of its investments. In particular, its compliance with section 5.6 of the code or any other prudent investment tests or economic analysis which demonstrated that its past capex was efficient. This is consistent with the efficiency criteria set out in the 1999-2004 revenue cap decision[2].

EnergyAustralia has only provided one final and one draft regulatory test application. The ACCC has identified two projects, the Macquarie Park and Beresfield substations, where EnergyAustralia has not conducted the regulatory test and failed to comply with its code obligations. The ACCC is in the process of writing to the National Electricity Code Administrator (NECA) regarding these matters.

The ACCC considers that, for a number of projects, EnergyAustralia has not provided an economic analysis of options to demonstrate that the option chosen was the most efficient means of addressing a problem on its network.

GHD was also unsuccessful in their attempts to obtain from EnergyAustralia a robust economic analysis of options considered when developing past capital projects, and as a result did not offer a conclusion about the efficiency of EnergyAustralia's past capex.

For the projects included in the 1999-2004 revenue cap decision, the ACCC's draft decision is that these projects are prudent investments and will be rolled into the RAB at their actual cost. For projects not included in the 1999-2004 revenue cap decision, where EnergyAustralia has demonstrated that its capex projects are efficient (Green Square project, replacement and refurbishment program and non-system capex), the ACCC will allow the full costs of the project to be rolled into the opening RAB.

The ACCC does not consider that EnergyAustralia has demonstrated a need for the undergrounding of transmission mains at Homebush and hence the ACCC's draft decision is to exclude this project from the opening RAB.

For the CBD project, the ACCC has determined that EnergyAustralia was prudent in undertaking the regulatory test and that, if the investment had occurred as planned then it would have been deemed prudent. However, the ACCC has also determined that the entire cost of the upgrade is not necessarily prudent because of the cost increases.

Without a demonstration that EnergyAustralia was prudent in incurring these cost increases the ACCC will not roll the entire spend of $62 million into the RAB for the final revenue cap decision. Therefore, consistent with the draft TransGrid revenue cap

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[2] ACCC, *NSW and ACT Transmission Network Revenue Caps – 1999/00-2003/04 – Decision*, 25 January 2000.

decision[3] the ACCC will disallow any return on EnergyAustralia's investment in the CBD upgrade during the period of construction for the draft decision. Adopting this approach would mean reducing the carried forward value of this project by $8.7 million or 14 per cent.

For the remaining projects, the ACCC considers that EnergyAustralia has failed to provide sufficient information to demonstrate that these projects were efficient investments. Without sufficient information the ACCC is unable to ascertain an efficient level of expenditure for these projects. Therefore, the ACCC's draft decision will also disallow any return on EnergyAustralia's investment in these projects during the period of construction for the draft decision.

With respect to past capex, the ACCC's draft decision is to allow $125 million to be rolled into the opening RAB, including the foregone rate of return.

The ACCC's draft decision is that the opening RAB for the 2004-2009 regulatory period is $628.6 million. This is a substantial increase of approximately 37 per cent on the opening RAB for the 1999-2004 revenue cap. This increase is the result of:

- a considerable overspend on the capital allowance included in the 1999-2004 revenue cap decision
- assets changing classification.

The impact of the assets changing classification contributes 53 per cent to the increase in the opening RAB and excluding its impact would result in an increase of only 18 per cent.

1.3 Forecast capex

EnergyAustralia has provided its in principle support to exploring the development of a new ex-ante capex framework approach.

The ACCC acknowledges that EnergyAustralia's initial application was not prepared with the objective of setting a fixed cap for capital expenditure, but rather to determine a path of prices and cash flows. The ACCC therefore considers that EnergyAustralia's request to resubmit its future capex application is reasonable.

In order for EnergyAustralia and TransGrid to publish transmission prices by 15 May 2004 the ACCC has provided a provisional capex allowance that EnergyAustralia can use as a guide in setting and subsequently publishing transmission prices. The ACCC has used EnergyAustralia's proposed capex allowance of $183.8 million to set the maximum allowed revenue (MAR) (see Table 1.1 below). This will enable EnergyAustralia to prepare its transmission prices for the 2004/05 financial year and any adjustments required will be made in the final revenue cap decision.

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[3] ACCC, *NSW and ACT Transmission Network Revenue Caps – TransGrid 2004/05 – 2008/09 – Draft Decision*, 28 April 2004.

The ACCC will consider making its final revenue cap decisions using the ex-ante approach. To do this the ACCC anticipates that EnergyAustralia will submit a proposal on how its forecast capex should be treated under an ex-ante approach. This will require further consultation with interested parties and additional time to make a final decision. A proposed timetable can be found in chapter 4.

Table 1.1 ACCC's draft decision capex ($m 2003/04)

	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Growth driven total	23.7	14.6	7.7	9.8	10.8	66.6
Replacement total	12.6	14.4	29.9	20.7	11.9	89.5
Transmission non-system	5.6	5.6	5.3	5.6	5.6	27.7
Total capex	**41.9**	**34.9**	**42.9**	**36.1**	**28.3**	**183.8**

Note: numbers may not add due to rounding

1.4 Operating and maintenance expenditure

In order to judge whether or not EnergyAustralia's proposed operating and maintenance expenditure (opex) requirement and hence operating and maintenance practices are efficient, as required by the code, the ACCC needs to be confident of the starting point for future expenditures. Hence GHD was engaged and commenced its review of EnergyAustralia's proposed opex by analysing EnergyAustralia's opex in the 1999-2004 regulatory period, with a view to providing the ACCC with guidance about the reasonableness of both the opex starting point and path for the 2004-2009 regulatory period.

When EnergyAustralia's first revenue cap was being determined by the ACCC, EnergyAustralia was limited in its ability to provide an accurate estimate of the transmission component of its network operating costs. As a result, EnergyAustralia estimated these costs via a global allocation based on the proportion of the replacement cost of transmission assets relative to total network assets.

Three sets of opex data exist for the 1999-2004 regulatory period, reflecting different allocation frameworks, and different definitions of transmission assets. It is important to bear in mind that despite the historical nature of these measures, all three are approximations and the "true transmission opex" cannot be determined. The three sets of data are as follows.

- Original opex: based on the original definition of transmission assets agreed by the ACCC in 1998, and apportioned using a global allocation framework.

- Amended opex: based on the original definition of transmission assets agreed by the ACCC in 1998, and apportioned using an asset class allocation framework.
- New opex: based on the new definition of transmission assets agreed to by the ACCC in 2003, and apportioned using an asset class allocation framework.

EnergyAustralia proposes a total opex allowance of $24.4 million in 2004/05 increasing to $27.7 million by 2008/09. This is an increase in real terms of 14 per cent over the period. This proposed opex requirement has been developed taking into account the increased amount of transmission assets and using the revised allocation of opex by asset class. EnergyAustralia's proposed opex for 2004/05 represents a step increase of around 13 per cent over its forecast opex for 2003/04, and a 39 per cent increase when compared to the opex approved by the ACCC for 2003/04.

GHD contends that the most appropriate definition of opex to use when reviewing past opex is the definition used at the time of the ACCC's 1999-2004 revenue cap decision. That is, the original definition of transmission assets and the global allocation framework.

The ACCC agrees with GHD and considers that the review of opex for the 1999-2004 regulatory period must be undertaken using the same definition of transmission assets and cost allocation methodology that was used at the time of the 1999-2004 revenue cap decision. If a different definition was used, the ACCC would be considering the efficiency of EnergyAustralia's opex by comparing forecast opex on one set of assets with actual opex on a different set of assets. This would inevitably lead to a less accurate outcome than that which would be achieved by comparing forecast and actual opex on the same set of assets.

The ACCC further considers that a number of adjustments need to be made to EnergyAustralia's proposed opex starting point for the 2004-2009 regulatory period. These adjustments reflect inefficient expenditures as identified by GHD or the ACCC. The impact of these adjustments on EnergyAustralia's opex for the 1999-2004 regulatory period is summarised in Table 1.2.

Table 1.2 EnergyAustralia's opex adjusted for efficiencies ($m 2003/04)

	1999/00	2000/01	2001/02	2002/03	2003/04
EnergyAustralia's actual opex	24.35	26.70	31.14	27.91	28.78[1]
Adjustments:					
Superannuation		1.81	4.37	1.91	1.97[1]
Olympics	0.20	0.10			
Insurance			0.34		
General efficiency	0.12	0.27	0.47	0.56	0.75
ACCC adjusted opex	**24.03**	**24.52**	**25.96**	**25.44**	**26.06**

1. These forecasts were not provided and hence used a 2002/03 estimate including an assumed CPI adjustment of 3.1 per cent.

GHD states that the new opex allocation framework provides a better representation of actual transmission costs, noting that in-depth analysis of transmission opex would require either a full assessment of whole of business opex or a splitting of the transmission and distribution accounts. GHD also notes the new asset definition has been accepted by the ACCC and as such needs to be incorporated into the future estimates of opex.

GHD has provided estimates of the impact of the change in asset definition and allocation methodology on the original estimates of opex by EnergyAustralia. The change, expressed as a proportion of the original estimate is then used to amend the adjusted opex for the 1999-2004 regulatory period. The ACCC has followed this methodology to estimate the new starting point for EnergyAustralia's opex for the 2004-2009 regulatory period. Table 1.3 sets out the calculation for determining this proportion to apply to the ACCC adjusted opex (in Table 1.2).

Table 1.3 EnergyAustralia's opex amended for new asset definition and allocation framework ($m 2003/04)

	1999/00	2000/01	2001/02	2002/03	2003/04
EnergyAustralia's actual opex[2]	24.35	26.70	31.14	27.91	28.78[1]
EnergyAustralia's new opex[3]	23.00	23.82	23.02	22.30	21.58
EnergyAustralia's new opex ÷ EnergyAustralia's actual opex (%)	94.46	89.21	73.92	79.90	74.98[1]
ACCC adjusted opex[2]	24.03	24.52	25.96	25.44	26.06[1]
EnergyAustralia's new to actual opex proportion (%)	94.46	89.21	73.92	79.90	74.98[1]
ACCC new opex[3]	**22.70**	**21.87**	**19.19**	**20.33**	**19.54**

1. These forecasts were not provided and hence used a 2002/03 estimate including an assumed CPI adjustment of 3.1 per cent.
2. Based on original definition of transmission assets and global allocation framework.
3. Based on new definition of transmission assets and revised asset class allocation framework.

The ACCC new opex set out in Table 1.3 reflects the ACCC's view of an efficient opex spend by EnergyAustralia for the 1999-2004 regulatory, based on the new asset definition and allocation framework.

The ACCC's calculation of the new 2003/04 opex, after adjustments for ACCC identified efficiencies, new transmission asset definition and new allocation framework implies a shift in EnergyAustralia's starting point of $2.04 million down from $21.58 million to $19.54 million in the year 2003/04. This reflects the ACCC's assessment of the efficient opex for transmission assets for this year if the new asset definition and allocation framework is used.

In order to derive the ACCC's proposed allowance for opex in the 2004-2009 regulatory period, EnergyAustralia's proposed opex is adjusted to reflect the new starting point, and then the impact of identified efficiency drivers are taken into account.

Table 1.4 EnergyAustralia's opex ($m 2003/04)

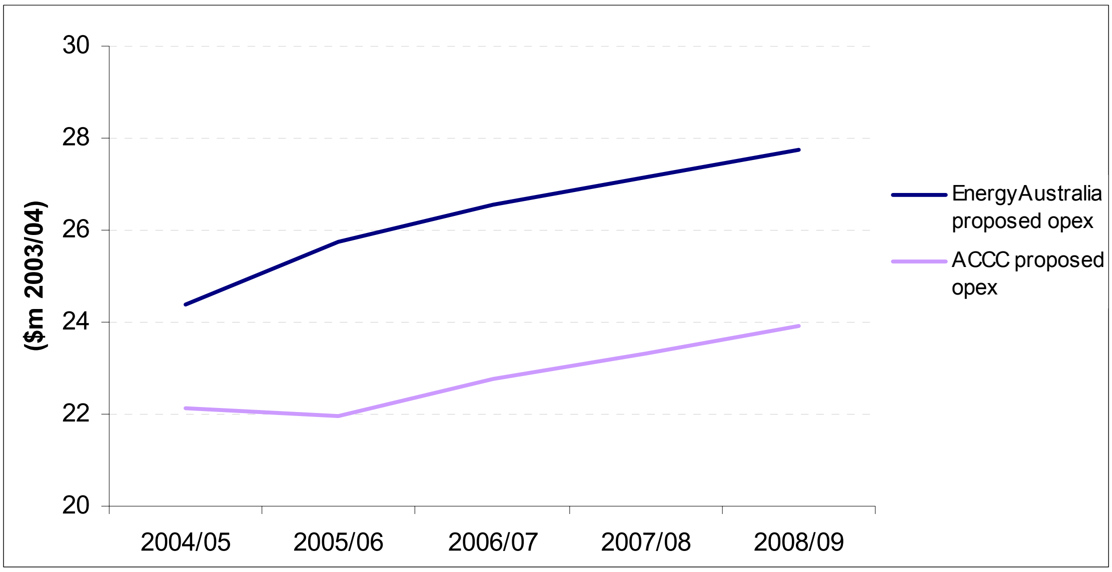
	2004/05	2005/06	2006/07	2007/08	2008/09	Total
EnergyAustralia's proposal[1]	24.37	25.75	26.56	27.14	27.73	131.55
less: ACCC starting point variation ($2.04)	22.33	23.71	24.52	25.10	25.69	121.35
less: cost driver variation						
Confidential project	0.07	(1.42)	(1.42)	(1.42)	(1.42)	(5.61)
IT	(0.67)	(0.71)	(0.74)	(0.75)	(0.77)	(3.64)
Self insurance	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.10)
add debt raising cost	0.40	0.41	0.41	0.42	0.43	2.07
ACCC proposed opex	**22.11**	**21.97**	**22.75**	**23.33**	**23.91**	**114.07**

1. EnergyAustralia's opex forecasts do not include debt raising costs as they were included in its WACC calculations.

For the purposes of calculating an efficient starting point opex for 2004/05, the ACCC considers that EnergyAustralia's opex in the 1999-2004 regulatory period included inefficiencies of around $2 million per annum. The ACCC also considers that different cost drivers will impact on EnergyAustralia's opex requirement in the 2004-2009 regulatory period.

Accordingly, other potential efficiencies identified by the ACCC for opex in the 2004-2009 regulatory period include IT, self insurance and a confidential project. The ACCC has also included an allowance for debt raising costs. These adjustments and the ACCC's proposed opex allowance are set out in Table 1.4 and illustrated in Figure 1.1.

Figure 1.1 Opex 2004-2009 regulatory period ($m 2003/04)



1.5 Cost of capital

The ACCC uses the risk adjusted rate of return required by investors in commercial enterprises facing similar business risks to establish the weighted average cost of capital (WACC) for EnergyAustralia.

The ACCC has carefully considered the values that should be assigned to EnergyAustralia's WACC, given the nature of its business and current financial circumstances. The parameter values adopted for the draft decision are shown in Table 1.5 and also include the corresponding parameters proposed by EnergyAustralia.

The main difference in the values proposed by EnergyAustralia and adopted in the ACCC's draft decision relates to the debt margin and equity beta. The ACCC considers that it is appropriate to benchmark a debt margin based on 'A' rated corporate bonds with a maturity of ten years. The ACCC notes that an equity beta of 1.0 is biased towards the service provider if exclusive reliance on market data is used. However, the ACCC would like to be confident that the market derived beta would not systematically under compensate the transmission network service provider (TNSP) and therefore, on balance, the ACCC is proposing an equity beta of 1.0 for EnergyAustralia.

Table 1.5 Comparison of cost of capital parameters

Parameter	Draft decision	EnergyAustralia's proposal
Nominal risk-free interest rate (r_f)	5.89 %	5.55 %
Expected inflation rate (f)	2.44 %	3.34 %
Debt margin (over r_f)	0.87 %	1.475 %
Cost of debt $r_d = r_f +$ debt margin	6.76 %	7.025 %
Market risk premium (r_m-r_f)	6.00 %	6.00 %
Gearing (D/V)	60 %	60 %
Value of imputation credits γ	50 %	50 %
Asset beta β_a	0.40	0.425
Debt beta β_d	0.00	0.00
Equity beta βe	1.00	1.06
Nominal post-tax return on equity	11.86 %	11.89 %
Post-tax nominal WACC	6.84 %	6.95 %
Pre-tax real WACC	6.94 %	7.47 %
Nominal vanilla WACC	**8.80 %**	**8.97 %**

The above parameters have been calculated in accordance with the ACCC's Draft Statement of Principles for the Regulation of Transmission Revenues (DRP)[4] and are

[4] ACCC, *Statement of Principles for the Regulation of Transmission Revenues – Draft*, 27 May 1999.

consistent with its previous revenue cap decisions. Some of the parameters vary over time according to market conditions (for example, the nominal risk-free rate adopted for the draft decision is different to that proposed by EnergyAustralia). They will be revised on the date of the final decision.

1.6 Total allowed revenue

The ACCC's role as regulator of transmission revenues is limited to determining a TNSP's MAR. The MAR is calculated by adding (or deducting) a financial incentive related to service standard performance and pass through amounts to (or from) the allowed revenue (AR). The ACCC uses a building block approach to estimate the AR in the first year of the regulatory period and this AR is adjusted to determine subsequent MARs for the remainder of the regulatory period.

In its application, EnergyAustralia requests a smoothed revenue of $108 million in 2004/05, increasing to $128 million in 2008/09. In 2003/04, EnergyAustralia's comparable AR is $78 million.

Using the estimates of the components of the building block approach (as described in section 7.8) the ACCC proposes a smoothed AR that increases from $91.3 million in 2004/05 to $113.1 million 2008/09, as shown in Table 1.6.

Table 1.6 EnergyAustralia's smoothed AR ($m nominal)

	2003/04[1]	2004/05	2005/06	2006/07	2007/08	2008/09
Smoothed AR	78.08	91.27	96.28	101.58	107.16	113.05

1. Final year of 1999-2004 revenue cap decision.

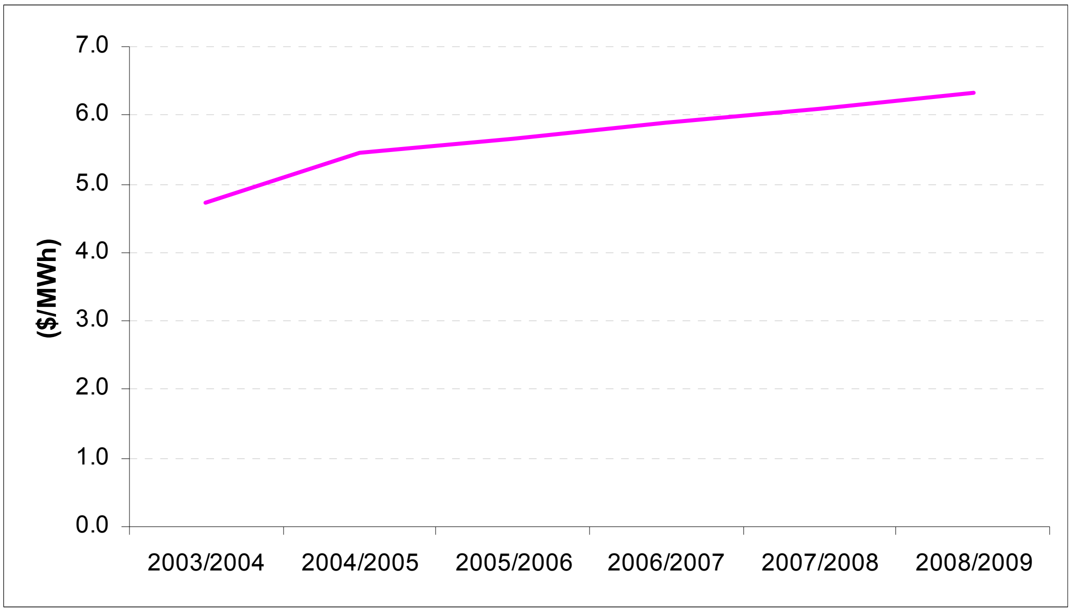
The revenue increase over the regulatory period consists of:

- an initial increase of about 16.9 per cent (nominal) in the first year; mainly as a result of increases in the asset base from:
  - assets moving from distribution to transmission, which accounts for the majority of the increase between 2003/04 and 2004/05. In fact, if these assets were excluded from the asset base, the first year increase would only be 3.7 per cent (nominal)
  - capex incurred in the 1999-2004 regulatory period.
- a subsequent increase of around 5.5 per cent per annum (nominal) on average during the remainder of the regulatory period (mainly as a result of the large capex program the ACCC has provisionally adopted while developing an ex-ante capex framework for the final decision).

Figure 1.2 shows the resulting price path of this draft decision over the regulatory period. The indicative 2004/05 price path represents a 15 per cent increase over 2003/04 and will increase at an average of 4 per cent over the subsequent years.

The ACCC estimates that its draft decision will result, on average, in a 6 per cent per annum increase (in nominal terms) in transmission charges over the regulatory period. Transmission charges represent approximately 10 per cent of end user electricity charges.

Figure 1.2 Illustrative price path 2003–04 to 2008–09 ($/MWh)



1.7 Service standards

In order to set financial incentives, the ACCC proposes to implement GHD's proposed performance measures and targets for EnergyAustralia. For the 2004-2009 regulatory period, the ACCC's draft decision is to adopt the weightings and targets recommended by GHD (Table 1.7).

Table 1.7 Service standards proposed by GHD

Performance measure	Unit of measure	Revenue at risk (%)	Collar	Dead band knee 1	Target	Dead band knee 2	Cap
Transmission circuit availability	%	1	95.3	-	96.1	-	96.7
Average outage duration	Data to be measured by EnergyAustralia during 2004-2009 regulatory period						

Therefore, for the 2004-2009 regulatory period, EnergyAustralia has a financial incentive applying to its performance as measured by transmission circuit availability.

However, EnergyAustralia is required to also measure its transmission circuit availability with the inclusion of:

- transformers and reactive plant, in accordance with the proposed standard definition
- significant lengths of new 132 kilovolt (kV) lines and other equipment, resulting from the re-classification of some assets from distribution to transmission during the period of the 1999-2004 regulatory period.

In addition to this, the ACCC requires that EnergyAustralia report on the other performance measures contained in its service standards guidelines. This reporting requirement excludes the need to report on inter-regional constraints because EnergyAustralia does not own or operate any inter-regional assets.

2. Introduction

2.1 Background

EnergyAustralia owns and operates a part of the electricity transmission network in NSW. EnergyAustralia also owns and operates an electricity distribution network in NSW. Currently EnergyAustralia's distribution network is regulated by the IPART, and the transmission network is regulated by the ACCC.

EnergyAustralia is the only network owner in the National Electricity Market (NEM) which has its revenue regulated by the ACCC and its pricing by a state regulator. EnergyAustralia argues that this dual regulation is inefficient. This assessment is supported by interested parties who note that this dual form of regulation is unnecessarily complex.

The ACCC concurs with EnergyAustralia on this matter and considers that the most sensible approach in the future is to move the regulation of EnergyAustralia's entire network to one regulatory body. However, under the current code definition, the ACCC is required to regulate the transmission portion of EnergyAustralia's asset base.

The ACCC is currently considering options to address this issue and notes that the current discussion regarding the responsibilities of the proposed Australian Energy Regulator (AER) may provide a solution to this problem.

EnergyAustralia submitted its revenue cap application on 23 September 2003. After reviewing its initial application, the ACCC requested that EnergyAustralia submit additional information in support of its application. Supplementary information was provided by EnergyAustralia in October and November 2003.

2.2 Code requirements

The code establishes a regulatory framework which:

- specifies that the ACCC will determine the revenue caps to be applied to the non-contestable elements of participating TNSPs
- sets out how those regulated revenues will be translated into network charges.

Box 2.1 Objectives and principles of the regulatory regime

The code establishes that:

1. the transmission revenue regulatory regime must achieve outcomes which:
   - (a) are efficient and cost effective
   - (b) are incentive based, including the sharing of efficiency gains between network users and owners as well as the provision of a reasonable rate of return (without monopoly rents) to network owners
   - (c) foster efficient investment in the transmission sector and upstream and downstream of it
   - (d) foster efficient operation, maintenance and use of network assets
   - (d) recognise pre-existing government policies on asset values, revenue paths and prices
   - (e) promote competition
   - (f) are reasonably accountable, transparent and consistent over time.
2. the regulation of aggregate revenue of transmission networks must:
   - (a) be consistent with the regulatory objectives (see 1 above)
   - (b) address monopoly pricing concerns, wherever possible, through the competitive supply of network services but otherwise through a revenue cap
   - (c) promote efficiency gains and a reasonable balance between network augmentations and supply and demand side options
   - (d) promote a reasonable rate of return to network owners on an efficient asset base where:
     - (i) the value of new assets is consistent with take-or-pay contracts or augmentation determinations
     - (ii) the value of existing assets are determined by jurisdictional regulators and must not exceed their deprival value
     - (iii) any asset revaluations undertaken by the ACCC are consistent with Council of Australian Governments decisions.
3. the form of the economic regulation shall:
   - (a) be a revenue cap with a CPI-X incentive mechanism, or some other incentive based variant, for each network owner and/or service provider
   - (b) have a regulatory control period of not less than five years
   - (c) take into account expected demand growth, service standards, weighted average cost of capital, potential efficiency gains, a fair and reasonable risk adjusted return on efficient investment and ongoing commercial viability of the transmission industry
   - (d) only apply to those services the ACCC does not expect to be offered on a contestable basis.

Source: National Electricity Code, clauses 6.2.2 - 6.2.5.

In May 1999 the ACCC published its DRP, which set out how it proposed to regulate transmission network revenues. The ACCC is currently reviewing the DRP and has released a discussion paper for public consultation.[5] Whilst the ACCC has followed the principles set out in the DRP for the most part, some changes to the regulatory framework have been made to accommodate EnergyAustralia's concerns and reflect the ACCC's increased regulatory experience.

2.3 Process

The ACCC will set a revenue cap for EnergyAustralia from 1 July 2004 until 30 June 2009. This is consistent with the code which specifies a minimum period of five years.

2.3.1 Revenue cap setting process

As part of the revenue cap setting process the ACCC:

- received an application from EnergyAustralia on 23 September 2003
- ascertained it contained insufficient information in a number of key areas and requested more information
- received additional information from EnergyAustralia in support of its application in October and November 2003
- submitted a further detailed information request to EnergyAustralia on 1 December 2003, with a response received on 4 February 2004
- engaged GHD to assess EnergyAustralia's opening regulatory asset base (RAB), capital and operational expenditure and proposed service standards
- conducted detailed interviews with EnergyAustralia
- invited interested parties to comment on EnergyAustralia's application and GHD's report
- consulted with EnergyAustralia and other interested parties
- released this draft decision on 4 May 2004.

The ACCC seeks submissions from interested parties on this draft decision. The closing date for submissions is 2 July 2004.

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[5] ACCC, *2003 Review of Draft Statement of Principles for the Regulation of Transmission Revenues – Discussion Paper*, 28 August 2003.

A copy of EnergyAustralia's application, additional information, GHD's report and submissions are available on the ACCC's website.[6]

The following is an indicative timetable for finalising the decision.[7]

- Public forum on draft decision (if requested) by the end of June 2004.
- EnergyAustralia resubmits future capex application by the end of October 2004.
- ACCC releases consultant's report on EnergyAustralia's future capex application for public consultation by mid December 2004.
- ACCC releases supplementary draft decision on forward capex and invites submissions by mid February 2005.
- Public forum on supplementary draft decision (if requested) by early March 2005.
- ACCC releases its final decision by mid April 2005.

2.4 Structure

The structure of this draft decision is shown in Table 2.1.

Table 2.1 Report structure

Chapter	Title	Description
3	Opening asset base	Establishing the RAB at 1 July 2004
4	Forecast capital expenditure	Estimating the capex allowance
5	Operating & maintenance expenditure	Estimating the opex allowance
6	Cost of capital	Calculating the weighted average cost of capital
7	Total allowed revenue	Calculating the total revenue
8	Service standards	Establishing service standard incentives

[6] www.accc.gov.au

[7] The full timetable is at section 4.11.2.

2.5 Overview of EnergyAustralia's network

2.5.1 EnergyAustralia's network

EnergyAustralia operates a network that covers 22,275 square kilometres and delivers electricity to more than 1.4 million homes and businesses. Its network includes the Sydney, Central Coast, Newcastle and Hunter Valley areas. While primarily a distribution company, around 12 per cent of its network is classified as transmission assets under the existing code definition.

Similar to other TNSPs, EnergyAustralia has witnessed a significant growth in its peak system demand over the 1999-2004 regulatory period, particularly over the summer months.

EnergyAustralia's transmission network largely comprises a system of underground 132 kV cables and overhead feeders, with their associated exit assets, in the Sydney metropolitan area. EnergyAustralia also owns a small number of transmission assets on the Central Coast, and in the Newcastle and Hunter regions.

The following figures provide a schematic representation of EnergyAustralia's transmission network.

Figure 2.1 EnergyAustralia's transmission network in the Sydney and Central Coast areas as at 1 July 2004

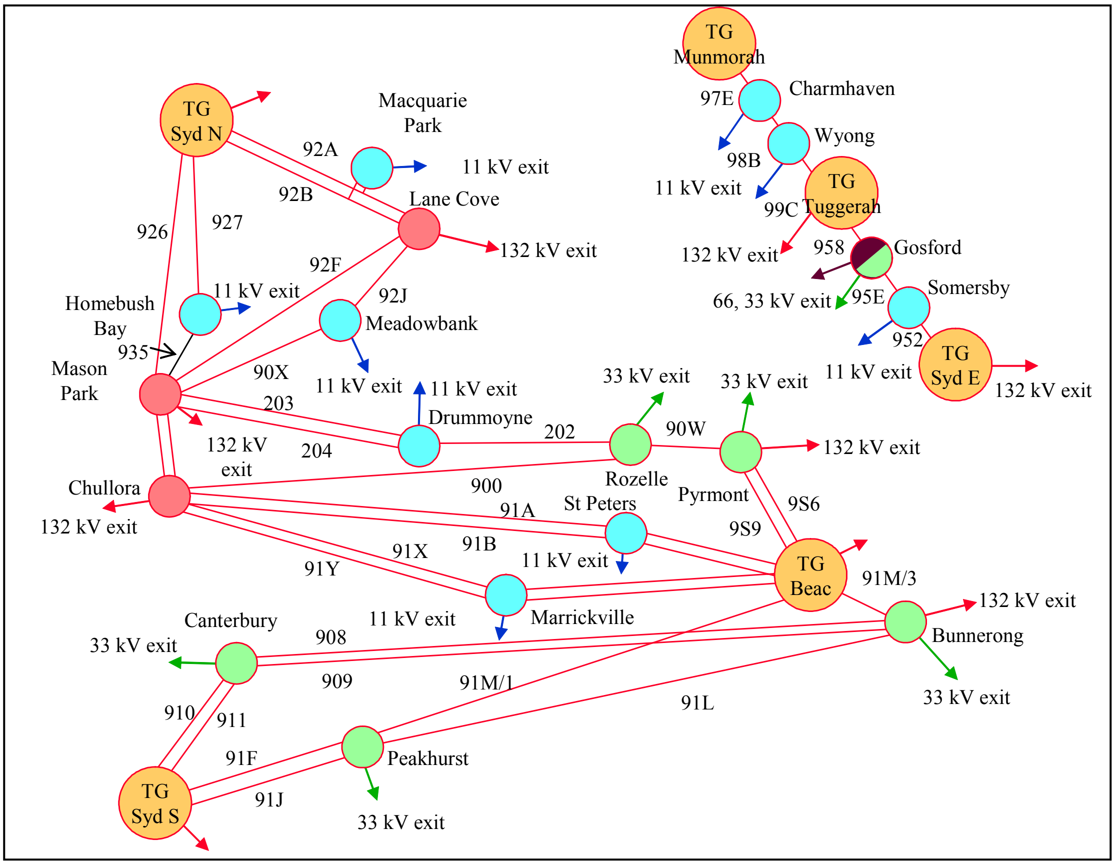
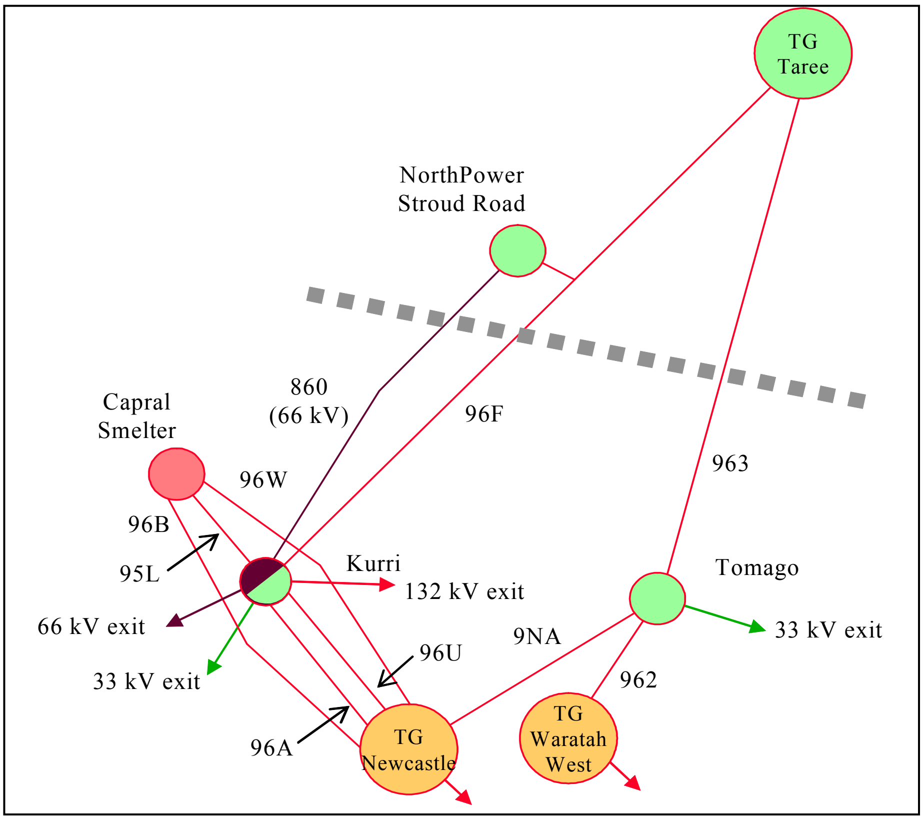


Figure 2.2 EnergyAustralia's transmission network in the Newcastle and Hunter regions as at 1 July 2004



2.5.2 EnergyAustralia and TransGrid joint network planning

EnergyAustralia and TransGrid state that they work closely together via joint network planning and maintenance processes. EnergyAustralia and TransGrid also cooperate in formulating transmission network prices in NSW. Both EnergyAustralia and TransGrid collect Transmission Use of System (TUOS) charges from customers. However, due to the components of the pricing (i.e. fixed and variable), EnergyAustralia collects revenues that should be directed to TransGrid, and TransGrid collects revenues that should be directed to EnergyAustralia. To ensure that neither earns more than its allowed revenue, a net transfer of revenue occurs every month.

3. Opening asset base

3.1 Introduction

This chapter sets out the ACCC's draft decision on EnergyAustralia's opening RAB for the 2004-2009 regulatory period. It sets out the relevant requirements of the code, the relevant provisions of the DRP and analyses a number of issues raised in EnergyAustralia's application. It then compares EnergyAustralia's actual capex over the 1999-2004 regulatory period to that allowed in the 1999-2004 revenue cap decision. The ACCC's draft decision is set out in section 3.20.

The ACCC must determine an opening RAB value for EnergyAustralia's non-contestable transmission assets as at 1 July 2004.

The ACCC determined the opening RAB for the 1999-2004 revenue cap decision to be $457.4 million. This value was based on an ODRC valuation conducted by GHD in February 1999 and proposed by EnergyAustralia in its 1999-2004 revenue cap application. In arriving at the valuation of EnergyAustralia's network assets at 1 July 1999, the ACCC adopted the same ODRC principles used in the valuation of TransGrid's assets at that time.

The ACCC accepted the initial prudency of the forecast capex amounts included in EnergyAustralia's application and a total capex allowance of $56.7 million was included in the 1999-2004 revenue cap decision. The 1999-2004 revenue cap decision, while accepting the initial prudency of the planned capex, emphasised that the ACCC was not approving the capex *per se* and that actual capex would be subjected to an *ex-post* reasonableness assessment. The ACCC would consider optimising the regulatory value of new assets if expenditure failed that test.

Such an approach is consistent with the DRP, which states that in relation to rolling capex into the RAB:

> The Commission may review the prudency of large capital expenditure and may seek assurance that the TNSP has complied with the requirements of clause 5.6 of the NEC.[8]

EnergyAustralia also accepts the ACCC's right in this regard, noting in its application:

> [EnergyAustralia] accept that it is appropriate for the ACCC to require an ex post assessment of the efficiency of EnergyAustralia's capital programs.[9]

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[8] ACCC, *Statement of Principles for the Regulation of Transmission Revenues – Draft*, 27 May 1999 p56.

[9] EnergyAustralia, *EnergyAustralia's Transmission Revenue Determination 2004-2009 Application*, September 2003 p43.

Therefore, in determining an opening RAB for the 2004-2009 regulatory period, the ACCC must conduct an *ex-post* assessment of past capex to determine whether it was prudent and efficient. Only efficient and prudent investments should be included in the RAB.

When it comes to assessing the efficiency of past capex, it must be recognised that an information asymmetry exists. TNSPs possess the information which enables them to forecast and ultimately determine an appropriate amount of capex for their networks. The code does not require TNSPs to seek the approval of the ACCC at the time it undertakes new investment in its network. Nor does it require TNSPs to provide information relating to new investment to the ACCC at the time this investment is undertaken. The ACCC relies on the TNSPs to supply such information during the revenue cap determination process.

This is particularly the case with past capex not forecast at the time of the previous revenue cap decision. The ACCC recognises that new capital projects may arise or the timing of projects may need to change to reflect circumstances not envisaged at the time of the revenue cap decision. However, in the current regulatory framework the onus is on the TNSP to adequately document the circumstances which led to the actual capex differing from that forecast at the time of the revenue cap decision. Under chapter 5 of the code, the TNSP also needs to adequately document the steps it has taken in ensuring only efficient investments are undertaken during the regulatory period. The regulatory test[10] sets out the principles the ACCC would expect a TNSP to follow when it comes to documenting its economic assessments and justifying its investments.

Therefore, in assessing EnergyAustralia's past capex, the ACCC sought information from EnergyAustralia to demonstrate the efficiency of its investments; in particular, its compliance with section 5.6 of the code or any other prudent investment tests or economic analysis which demonstrated that its past capex was efficient.

This is also consistent with the efficiency criteria set out in the 1999-2004 revenue cap decision which stated:

> Further, in making both the *ex-ante* and *ex-post* assessments, the Commission will have regard to whether the network planning requirements set out in Chapter 5 of the NEC were followed as a guide for assessing whether the proposed expenditures are the most efficient and reasonable given the available (competitive) options.[11]

3.2 Code requirements

In determining an opening RAB for the regulatory reset, the ACCC is bound by the relevant provisions in the code. Clause 6.2.3(d)(4)(iv) of the code states that:

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[10] ACCC, *Regulatory Test for New Interconnectors and Network Augmentations*, 19 December 1999. The regulatory test is currently under review.

[11] ACCC, NSW *and ACT Transmission Network Revenue Caps 1999/00-2003/04*, 25 January 2000 p138.

subject to clauses 6.2.3(d)(4)(i) and (ii), valuation of assets brought into service after 1 July 1999 ('new assets'), any subsequent revaluation of any new assets and any subsequent revaluation of assets existing and generally in service on 1 July 1999 is to be undertaken on a basis to be determined by the ACCC and in determining the basis of asset valuation to be used, the ACCC must have regard to:

A the agreement of the Council of Australian Governments of 19 August 1994, that deprival value should be the preferred approach to valuing network assets;

B any subsequent decisions of the Council of Australian Governments; and

C such other matters reasonably required to ensure consistency with the objectives specified in clause 6.2.2.

Therefore, the code gives the ACCC the discretion to determine the opening RAB for 1 July 2004 subject to the limitations detailed above. This differs to the 1999-2004 revenue cap, where the code specified that the ACCC must value sunk assets at the value determined by the Jurisdictional Regulator or consistent with the regulatory asset base established in the jurisdiction when determining the opening RAB (clause 6.2.4(d)(4)(iii)). It should be noted that, in relation to the 1999-2004 revenue cap decisions for TransGrid and EnergyAustralia, the ACCC was the Jurisdictional Regulator (clause 9.16.1). Accordingly, the ACCC undertook an ODRC valuation of the transmission networks operated by TransGrid and EnergyAustralia.[12]

With regard to capex, part B of chapter 6 of the code sets out the general objectives and principles the ACCC must follow in regulating transmission revenues. In particular, the code emphasises the need to provide a fair and reasonable rate of return on *efficient* capital investment (clauses 6.2.2(b)(2), 6.2.3(d)(4), 6.2.4(c)(5)).

3.3 Provisions of the DRP

The DRP elaborated on how the ACCC interpreted its code obligations with regard to regulating capital investment. The basic design of this arrangement is that:

- the ACCC would determine an allowance for capital expenditure based on a forecast at the start of the regulatory period (proposed statement S5.2)
- at the end of the period (after the investment had been made) the ACCC would assess the prudency of the actual capex (proposed statement S5.3).

[12] ACCC, *NSW and ACT Transmission Network Revenue Caps 1999/00-2003/04*, 25 January 2000 pages 60 and 135.

The test of prudent investment was "… the amount that would be invested by a prudent TNSP acting efficiently in accordance with good industry practice …"[13] The ACCC's approach to the determination of what constitutes a prudent and efficient investment is discussed in chapter 4 of the draft TransGrid revenue cap decision.

As stated above, consistent with the DRP and the 1999-2004 revenue cap decision, the ACCC is required to assess the prudency and efficiency of capital projects *ex-post* i.e. the assessment and the determination of the amount of expenditure to be included in the RAB is to be determined *after* the investment has been made. The determination of the capex forecast at the start of the period provides TNSPs with sufficient cash flow to finance their expected investment program. While this forecast is based on a reasonable assessment of likely investment over the period of the revenue control, it is not intended to represent a definitive assessment of efficient investment.

By implication, any difference between the actual expenditure and the forecast expenditure cannot simply be attributed to efficiency that is higher than expected (if actual capex is below forecast capex) or lower than expected (if actual expenditure is above forecast expenditure). Instead the ACCC foreshadowed in the DRP that it would assess the prudency of every capital project undertaken.

3.4 EnergyAustralia's application

In its application, EnergyAustralia propose an opening RAB of $702 million. This is based on an ODRC valuation conducted by SKM. EnergyAustralia contends that a new ODRC valuation is warranted because the 1999 valuation contains many material errors. In addition, EnergyAustralia states that the uncertainty surrounding the ACCC's roll forward approach was a key factor in its decision to propose a new ODRC valuation.

While proposing an ODRC valuation for the opening RAB for the 2004-2009 regulatory period, EnergyAustralia also states that it, in principle, supports the use of a roll-forward approach in determining the RAB and that a roll-forward methodology should be adopted for the subsequent regulatory period commencing in 2009.

EnergyAustralia provided no information on its capex program for the 1999-2004 regulatory period in its application beyond that contained within an SKM prudency assessment report which included a number of its past transmission projects (Attachment 6 to the application).

On 18 November 2003, EnergyAustralia submitted a summary of its capex over the 1999-2004 regulatory period and project specific documentation. EnergyAustralia states that all of its past capex is prudent and should be included in the opening RAB.

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[13] This is taken from proposed statement 5.1 on page 63 of the DRP. The full text of this statement also required that one of three other conditions be satisfied for investment to be deemed to be prudent. The first condition was that "incremental revenue generated by the capex exceeds the investment cost". This condition is obviously circular – as long as the ACCC determines that the investment is prudent the present value of revenues will be greater than the investment cost.

EnergyAustralia is also seeking the foregone rate of return on its capital overspend to be included in the opening RAB.

On 18 February 2004, EnergyAustralia submitted an updated opening RAB to the ACCC which considered more up to date information on the timing of capex and other issues. The new opening RAB proposed by EnergyAustralia is $680.2 million. This is based on the SKM ODRC valuation.

3.5 Roll-forward versus new ODRC valuation

3.5.1 Summary of issue

As stated above, EnergyAustralia has proposed an opening RAB for the 2004-2009 regulatory period based on an ODRC methodology. It has proposed this new ODRC valuation because it considers that there are inconsistencies and errors in the opening RAB for the 1999-2004 revenue cap, and that the ACCC did not provide it with initial advice on its proposed roll forward methodology.

3.5.2 Consultant's report

GHD is unable to form a firm conclusion on the overall efficiency of EnergyAustralia's past capex program. GHD is unable to reach a conclusion on EnergyAustralia's past capex because EnergyAustralia failed to provide adequate information on the development of cost estimates for each project and detailed or robust economic analysis/appraisal of options. Therefore, GHD is unable to reach a conclusion on the prudency of the opening RAB. For details on GHD's assessment of prudency of past capex see the individual project discussions below.

3.5.3 ACCC's considerations

As noted above, clause 6.2.3(d)(4)(iv) of the code gives the ACCC a discretion in relation to the determination of EnergyAustralia's opening RAB for the 2004-2009 regulatory period.

In the DRP the ACCC notes that it has the power to revalue the RAB using an ODRC methodology. On page 49 and in proposed statements S4.2 and S4.3 of the DRP the ACCC discusses the circumstances in which this might occur and the procedure that would be applied. However, it is equally clear from these principles that the ACCC is under no obligation to do so. In this case, the ACCC must determine whether, based on the reasons and material provided by EnergyAustralia, such a measure is justified.

As noted above, the ACCC undertook an ODRC valuation of EnergyAustralia's transmission assets in order to determine the opening RAB for the 1999-2004 revenue cap. EnergyAustralia's application provided little detail on the errors and inaccuracies it considers to exist in this ODRC valuation. After reviewing EnergyAustralia's application, the ACCC sought a full list of errors and inaccuracies in the 1999 ODRC valuation; in particular, material inconsistencies between the TransGrid and EnergyAustralia's valuations, and their order of magnitude.

On 31 October 2003, EnergyAustralia submitted additional information on asset valuation for the 2004-2009 regulatory period. This information provided a single example of how angle structures can cost up to five times more than a standard structure and outlined a single pricing example for one customer based on different valuations and stated that:

> the estimated magnitude of these types of unit rate differences undervalue EnergyAustralia's total regulatory asset base by more than 8 per cent.[14]

The ACCC considers that EnergyAustralia has failed to demonstrate that the ODRC valuation utilised in the 1999-2004 revenue cap is materially affected by error. EnergyAustralia has not provided any specific examples of errors in the 1999 ODRC valuation. In addition, the ACCC considers that EnergyAustralia has not provided sufficient supporting evidence regarding inconsistencies in the 1999 ODRC methodologies used for TransGrid and EnergyAustralia. EnergyAustralia has not provided specific examples of such inconsistencies.

Further, given the information provided to date, the ACCC is currently unable to determine if EnergyAustralia's capex between 1999 and 2004 is prudent and efficient. Hence, the ACCC questions the valuation of these assets in EnergyAustralia's proposed ODRC. This is discussed in more detail below.

Therefore, the ACCC does not believe there is justification for a revaluation of EnergyAustralia's asset base. The ACCC's preference is to roll-forward the opening asset base from the 1999-2004 revenue cap decision.

The ACCC's decision to adopt the roll-forward methodology in determining an opening RAB for the 2004-2009 regulatory period is based on a number of factors:

- that locking in the existing asset base valuation reduces regulatory uncertainty for TNSPs
- it is less likely to deter investment compared to periodic revaluations
- the ACCC considers that the initial valuation for the 1999-2004 regulatory period is appropriate.

The ACCC's preference for the roll-forward approach is consistent with the 2003 discussion paper "Review of the Draft Statement of Principles for the Regulation of Transmission Revenues", which provides more detailed explanation of the merits of the roll forward and ODRC methodologies.

Interested parties support the ACCC's preferred position to roll-forward the 1999-2004 revenue cap valuation to determine the opening asset base for the 2004-2009 regulatory period. The Energy Markets Reform Forum (EMRF) submission notes that the distribution businesses in NSW also claimed similar mistakes and anomalies in supporting their requests for revaluations of the asset base for the 2004 distribution

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[14] EnergyAustralia, *EnergyAustralia's Transmission Revenue Determination 2004-2009 Application*, September 2003 p37.

pricing review. These requests were rejected by IPART. The EMRF notes the reasons outlined in the 2003 discussion paper, "Review of the Draft Statement of Principles for the Regulation of Transmission Revenues", in addition to regulatory consistency support rejecting EnergyAustralia's revaluation request. The joint submission from a customers' group[15] also supports rejecting EnergyAustralia's request for a revaluation of its asset base. It notes that given the information asymmetry and resource availability all revaluations of the asset base will only be upward to the detriment of the customers.

In rolling forward the asset base, the ACCC has used the methodology shown in Box 3.1.

Box 3.1 ACCC's roll forward methodology

Opening asset base

\+ **capital expenditure** – **depreciation** – **asset disposals** + **indexation by CPI**

= **Closing asset base**

Details on the roll-forward methodology utilised for both TransGrid and EnergyAustralia can be found in the draft TransGrid revenue cap decision (chapter 3). The only difference between the roll forward methodology used for TransGrid and EnergyAustralia relates to the calculation of depreciation and asset lives. For TransGrid, the ACCC accepted the average remaining asset life methodology proposed by TransGrid based on National Economic Research Associate's (NERA) methodology. For EnergyAustralia, the ACCC has utilised an approach whereby assets are grouped into categories and depreciated using the average remaining asset life for assets in the category. The average remaining asset lives are revised figures provided by EnergyAustralia.

3.6 Assets changing classification

3.6.1 Summary of issue

In August 2003, EnergyAustralia wrote to the ACCC and IPART notifying both regulators of a number of changes in the configuration of its network assets. EnergyAustralia states that it has a number of system assets which have changed or would change classification from distribution to transmission before 30 June 2004. These changes in classification are the result of system changes or augmentations to the network over the 1999-2004 regulatory period. The value of these assets is $60 million. The assets are listed below in Table 3.1.

[15] The customers' group consists of Australian Business Ltd, Australian Consumers Association, Energy Action Group, Energy Users Association of Australia, and National Farmers Federation.

Table 3.1 Assets changing classification from distribution to transmission from 1 July 2004

Location	Asset
Inner Sydney Metropolitan	Feeder 9SA – Beaconsfield West to Surry Hills
Central Coast	Feeder 957 - Vales Point to Ourimbah
Central Coast	Feeder 95C - Ourimbah to Tuggerah
Central Coast	Feeder 951 - Ourimbah to West Gosford
Central Coast	Feeder 958 - Tuggerah to Gosford
Central Coast	Feeder 956 – West Gosford to Gosford
Central Coast	Feeder 95E – Gosford to Somersby
Central Coast	Feeder 95Z – Somersby to Mt Colah
Central Coast	Ourimbah sub-transmission substation
Central Coast	Gosford sub-transmission substation
Central Coast	West Gosford zone substation
Central Coast	Somersby zone substation
Central Coast	Mt Colah switching station

The ACCC reviewed the list of assets and explanations provided by EnergyAustralia and concluded that it appeared to meet the definition of transmission assets contained in the code. The ACCC and IPART agreed to these assets changing classification. Accordingly, from 1 July 2004, EnergyAustralia's distribution RAB would be reduced by $60 million and its transmission RAB increased by $60 million.

EnergyAustralia also advised the ACCC and IPART that it would have a number of assets changing classification over the course of the 2004-2009 regulatory period. The ACCC and EnergyAustralia have agreed that these assets will maintain their current classification over the 2004-2009 regulatory period, with any adjustments to the distribution and transmission RABs conducted at the end of the 2004-2009 regulatory period.

On 4 February 2004, EnergyAustralia wrote to the ACCC to acknowledge that an error had occurred in its August 2003 advice to the ACCC and IPART on assets changing classification from 1 July 2004. EnergyAustralia states that two zone substations on the central coast at Wyong and Charmhaven were not included in the list of assets changing classification. EnergyAustralia states that these assets should now be classified as transmission assets as they meet the code definition. The two substations have a total value of $20.2 million.

The ACCC has reviewed these assets and considers that these two substations meet the code definition of transmission assets. In particular, given that the two substations are connected to a transmission line which connects two of TransGrid's transmission supply points, is seems logical that these two substations should be classified as transmission exit points. The ACCC and IPART have agreed, along with the other assets listed above, that these assets should be excluded from the distribution RAB and included in the transmission RAB from 1 July 2004.

The increased transmission asset base also affects the net allocation of communications and non-system assets between the distribution and transmission asset bases. The overall impact of this is to increase the opening transmission RAB by a further $10.2 million with a corresponding decrease in the opening distribution RAB at 1 July 2004.

3.6.2 ACCC's considerations

The ACCC has included $80.2 million for the above listed network assets in the opening RAB for the 2004-2009 regulatory period, with a corresponding adjustment made to EnergyAustralia's distribution opening RAB by IPART. In addition, the ACCC has allowed for the transfer of $10.2 million for communications and non-system assets from the distribution to the transmission asset base at the same time.

The overall impact is to increase the transmission RAB by $90.4 million from 1 July 2004. This has the effect of increasing EnergyAustralia's proportion of transmission assets from approximately 10 to 12 per cent of its total network asset base.

3.7 Application of the regulatory test

3.7.1 Summary of issue

The ACCC promulgated the regulatory test in December 1999. From that date, the code required TNSPs to subject all augmentations to the regulatory test.

Prior to March 2002, clause 5.6.2(g) required TNSPs to analyse options to address system limitations within regions to identify the one that satisfies the regulatory test. Proposed inter-regional augmentations and interconnectors were subjected to the regulatory test under clauses 5.6.5 and 5.6.6.

The relevant provisions of the code were substantially revised in March 2002, when the Network and Distributed Resources code changes[16] were gazetted. This code change split network augmentations into two categories, either large (greater than $10 million) or small (between $1 million and $10 million).

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16 ACCC, *Determination – Applications for Authorisation – Amendments to the National Electricity Code - Network and Distributed Resources*, 13 February 2002.

With respect to new small network assets, clause 5.6.2A(b)(5)(i) requires a TNSP's Annual Planning Report to rank proposed augmentations in accordance with the principles in the regulatory test. A similar ranking must be undertaken for new small network assets not identified in the Annual Planning Report (clause 5.6.6A(c)).

With respect to new large network assets, clause 5.6.5(b)(3) requires a TNSP to rank the proposed augmentation against reasonable alternatives in accordance with the principles contained in the regulatory test.

As outlined above, in assessing the efficiency of EnergyAustralia's past capex, the ACCC sought information from EnergyAustralia on its compliance with section 5.6 of the code. Accordingly, on 26 August 2003 the ACCC requested a copy of all regulatory test applications conducted by EnergyAustralia from 1 July 1999 including application notices, submissions and final reports.

To date, EnergyAustralia has provided only one regulatory test application to the ACCC which was a combined application with TransGrid for the CBD project. EnergyAustralia has also provided a draft regulatory test application for the Green Square substation project and states that a final regulatory test assessment for this project will be released in the near future and prior to construction.

EnergyAustralia has provided only one annual planning report to the ACCC, the 2003 Annual Electricity System Development Review (AESDR)[17]. This report allocates only 5 out of 400 pages to the transmission planning review and does not meet the regulatory test requirements as set out in the code.

3.7.2 ACCC's considerations

The ACCC notes that the application of the regulatory test is a code requirement and, while it is not strictly a requirement that the results of the regulatory test be applied in setting a revenue cap under clause 6.2 of the code, the ACCC considers that capital investments which are comprehensively assessed using the regulatory test principles face a reduced risk of optimisation.

There are two projects not subjected to the regulatory test by EnergyAustralia which the ACCC considers should have been.

The Macquarie Park substation was commissioned in 2001. While the initial planning for this project occurred in 1998, the project did not receive EnergyAustralia board approval until late 2000, with construction commencing shortly afterwards. This occurred after the promulgation of the regulatory test but prior to the Network and Distributed Resources code changes. The ACCC considers that EnergyAustralia has not complied with its code obligations in respect of the Macquarie Park substation augmentation.

The construction of the Beresfield zone substation was approved by the EnergyAustralia board in early 2003, with construction commencing shortly

[17] EnergyAustralia, *Annual Electricity System Development Review*, May 2003.

afterwards. Again this is after the promulgation of the regulatory test and after the Network and Distributed Resources code changes. The project should be classified as a large network augmentation and the ACCC considers that EnergyAustralia has not complied with its code obligations in respect of the Beresfield zone substation augmentation.

The ACCC is in the process of writing to NECA regarding these matters.

3.8 Capital Governance Process

3.8.1 Summary of issue

In its application, EnergyAustralia states that its capital governance process provides continuous review and assurance that capital prudency and efficiency are being achieved. In addition, EnergyAustralia considers that it places great emphasis on the planning and project identification stage of the capital planning process, because assessment of customer needs and selection of the best ways to meet those needs exert the greatest leverage over customer value and cost.

EnergyAustralia states that it has made major improvements in the last two years at all levels of its capital investment process. EnergyAustralia claim to have been developing and implementing a new capital governance process since 2001. As a result of these changes, EnergyAustralia contends that its capital investment strategy is now designed to achieve specific outcomes at the lowest sustainable cost.

On 18 November 2003, EnergyAustralia submitted Attachment F "Economic Tests Applied to Transmission"[18]. This information sets out the planning and evaluation processes undertaken by EnergyAustralia for its capital investments, and clearly demonstrates EnergyAustralia's understanding of its various statutory obligations. EnergyAustralia notes that:

> [EnergyAustralia] also must comply with the National Electricity Law and the code that specifically refers to the ACCC's Regulatory Test for economic evaluation.

EnergyAustralia outlines a proposed process for growth driven capital projects which includes:

> EnergyAustralia will apply the full NEC process and Regulatory Test for major transmission projects. [19]

Based on information provided by EnergyAustralia, the following is the internal capital approval processes followed by EnergyAustralia:

- Constraints are identified and published in the AESDR.

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[18] EnergyAustralia, *Attachment F Economic Tests Applied to Transmission*, 18 November 2003.

[19] EnergyAustralia, *Attachment F Economic Tests Applied to Transmission*, 18 November 2003.

- Once a priority area of development has been identified, EnergyAustralia utilises a Value Management (VM) process to develop strategies to address the network issues. The VM studies allow a range of network and non-network solutions to be considered and often incorporate a wide network area to ensure a more strategic approach to network augmentations. The estimates in the VM study utilise high level costs which do not include site specific information. From the VM study, several top options are then selected for further development.

- From the VM studies, the network planning area in conjunction with EnergyAustralia's service provider, Enerserve, develops network augmentation options. Viable demand management options are considered internally in the first instance and further developed through market offers where viable.

- Augmentations are then assessed using the regulatory test to ensure the lowest net present value (NPV) cost option is selected (for reliability augmentations).

- Once this is complete, a business case is drawn up which outlines the costs and benefits of the preferred option which is approved by the relevant manager. This is then further developed through detailed engineering and cost estimates.

- Finally, a project is then put to the EnergyAustralia board for approval.

3.8.2 Consultant's report

As part of its review of EnergyAustralia's revenue cap application, GHD conducted an expenditure-related business systems review. The focus of the review was whether the systems and activities put in place by EnergyAustralia have delivered or will deliver the appropriate service levels in the most cost-efficient manner. The review covered both historic and forecast expenditure.

GHD's conclusion is that EnergyAustralia started the 1999-2004 regulatory period with weak systems and data, which reduced its decision making capacity. Importantly, GHD found that EnergyAustralia's performance in this regard was below that expected of a prudent operator.

With regard to specific business systems, GHD had the following findings.

- *Efficiency of organisation structure* – GHD concluded that, in general, the information did not exist to enable it to say with complete assurance that EnergyAustralia's past expenditure has been appropriate, prudent and efficient. Further, reporting systems and decision making protocols that are clear and traceable and enable EnergyAustralia to link information to decision making are now starting to be put into place. Finally, past systems and practices would have restricted EnergyAustralia's business performance over the 1999-2004 regulatory period.

- *Efficiency of service/project delivery systems* – EnergyAustralia had reasonably poor systems and processes in place, and decisions made would have had a higher risk level due to the input of poorer quality data.

- *Overall asset management planning* – EnergyAustralia had relatively poor systems in place at the start of the 1999-2004 regulatory period. The implications of this would have been decision making based on inferior information, and the full ramifications of these decisions would not have been fully understood at the time. EnergyAustralia were lagging the industry in this regard. Finally, EnergyAustralia do not have one single document which outlines the asset management plan for the entire organisation.

3.8.3 ACCC's considerations

The ACCC considers that GHD's findings on EnergyAustralia's business systems over the 1999-2004 regulatory period have significant implications for its capex and opex reviews. The ACCC is particularly concerned that EnergyAustralia's poor systems compromised its ability to make effective decisions. This in turn has implications for EnergyAustralia's ability to effectively manage its asset base, which is particularly important for companies which operate in capital intensive industries, such as electricity network providers.

The ACCC's conclusion is that EnergyAustralia's poor systems are likely to have compromised its ability to make efficient investment decisions over the 1999-2004 regulatory period. In addition, the lack of systems and processes has limited EnergyAustralia's ability to effectively provide information to the ACCC. As stated in the introduction of this chapter, this is a significant issue given the ACCC's reliance on EnergyAustralia to provide information to justify its investment decisions.

In reviewing EnergyAustralia's past capex projects, the ACCC was expecting to see the documentation consistent with the capital approval process outlined above. As the following discussion emphasises, much of this documentation has not been provided. This has had a severe impact on the ACCC's ability to determine whether or not the capex undertaken by EnergyAustralia over the 1999-2004 regulatory period has been prudent.

3.9 The ACCC's 1999-2004 revenue cap decision

3.9.1 Overview of 1999-2004 revenue cap decision

As stated above, the ACCC accepted the initial prudency of the forecast capex amounts included in EnergyAustralia's application and a total capex figure of $56.7 million was included in the 1999-2004 revenue cap decision. The allowance covered a small number of specific projects specified by EnergyAustralia.

The ACCC noted that the projects would be rolled into the RAB at their anticipated commissioning date. This had an impact on the projects included in the 1999-2004 revenue cap decision. In its 1999 application, EnergyAustralia proposed $25 million be included for the Sydney central connections project (part of the CBD upgrade) on a cash spend basis. While accepting the initial prudency of the Sydney central connections, the ACCC did not provide an allowance for this project in the 1999-2004 regulatory period as the project was not expected to be commissioned until after 30 June 2004.

Table 3.2 details the projects included in the 1999-2004 revenue cap decision. The amounts are expressed in nominal terms and exclude interest during construction.

Table 3.2 EnergyAustralia's capex allowance 1999-2004 ($m nominal)

Project	1999/00	2000/01	2001/02	2002/03	2003/04	Total
Feeders 910 & 911	0.0	0.0	10.0	0.0	0.0	10.0
Tuggerah to Munmorah feeder	0.0	3.5	0.0	0.0	0.0	3.5
Gosford to Ourimbah feeder[1]	0.0	0.0	0.0	0.0	7.0	7.0
Other augmentation	0.2	0.2	0.1	0.2	0.2	0.9
Transmission mains refurbishment	2.0	3.2	6.7	7.1	5.9	24.9
Substation replacement	1.0	1.2	1.5	2.0	2.0	7.7
Total	**3.2**	**8.1**	**18.3**	**9.3**	**15.1**	**54.0**

Note: Numbers may not add due to rounding.

1 While this project was included in the 1999-2004 revenue cap decision and built, it was included in IPART's regulatory accounts not the ACCC's. It is one of the assets changing classification (see section 3.6 more details).

3.9.2 Actual capital expenditure

EnergyAustralia's actual capex in the 1999-2004 regulatory period exceeded that forecast and included in the 1999-2004 revenue cap decision.

EnergyAustralia's application provided a limited explanation of this overspend. The application notes that the 1999-2004 regulatory period saw a significant increase in the overall rate of growth of peak system demand, particularly during summer.

When compiling its application for the 1999-2004 revenue cap, EnergyAustralia had forecast that winter peak demand would grow by 1.5 per cent per annum, and summer peak demand would grow by 2.5 per cent per annum. EnergyAustralia is now expecting peak demand growth to average 2.0 per cent for winter and 3.5 per cent for summer over the 1999-2004 regulatory period.

EnergyAustralia states that this higher than forecast demand contributed to increased capex over the current regulatory period. This led to both new projects being built and the construction of other projects being accelerated.

EnergyAustralia's actual capex is broken down by project in Table 3.3 below. Again the figures are in nominal dollars and presented on a cash spend rather than commissioning date basis.

Table 3.3 EnergyAustralia's actual capex ($m nominal)

Project	1999/00	2000/01	2001/02	2002/03	2003/04[1]	Total
Augmentations						
CBD upgrade	0.0	0.0	14.5	26.3	21.1	62.0
Feeders 910 & 911	0.5	4.0	0.6	0.0	0.0	5.1
Tuggerah to Munmorah feeder	0.2	3.5	0.3	0.0	0.0	4.0
Macquarie Park substation	0.0	0.0	11.8	-0.2	0.0	11.6
Beresfield substation	0.0	0.0	0.0	0.4	7.0.	7.4
Sub-total	**0.7**	**7.5**	**27.2**	**26.5**	**28.1**	**90.1**
Replacement and refurbishment						
Transmission mains undergrounding at Homebush	10.0	0.0	0.0	0.0	0.0	10.0
Green Square substation	0.0	0.0	0.2	0.2	3.7	4.2
Transmission mains refurbishment	3.4	0.0	0.0	0.0	0.0	3.4
Substation replacement	2.3	1.1	1.9	0.2	0.0	5.5
Oil containment and environment	0.9	0.3	0.1	0.2	0.0	1.6
Sub-total	**16.6**	**1.4**	**2.2**	**0.7**	**3.7**	**24.7**
Non-system	4.7	1.8	4.4	3.1	4.9	18.9
Other	0.0	0.9	0.5	0.2	0.0	1.5
Total	**22.0**	**11.6**	**34.3**	**30.5**	**36.7**	**135.2**

Note: Numbers may not add due to rounding.
1 forecast.

EnergyAustralia is expecting to have invested approximately $135 million by the end of the 1999-2004 regulatory period, almost $80 million more than allowed in the 1999-2004 revenue cap decision.

The majority of this overspend is in relation to augmentations to the network. This overspend is the result of a combination of actual project costs exceeding estimates (for example, the CBD upgrade), and projects being brought forward or new projects having to be built (for example, the Macquarie Park zone substation).

While EnergyAustralia built, or commenced building, two replacement projects not anticipated at the time of the 1999-2004 revenue cap decision, it underspent on its replacement and refurbishment program mainly as a result of lower than expected expenditure on refurbishment of transmission mains.

In additional information provided to the ACCC, EnergyAustralia claims to have spent $1.5 million in the 1999-2004 regulatory period on providing additional 132kV capacity in the lower Hunter region. EnergyAustralia states that this expenditure is related to the Tomago 132kV feeder augmentation and the Waratah West substation 330kV conversion projects. When asked for further details on these projects, EnergyAustralia confirmed that neither project would commence in the 1999-2004 regulatory period. Therefore, the ACCC has excluded both projects from the opening RAB.

A detailed discussion on each of the projects listed in Table 3.3 follows.

3.10 CBD upgrade

3.10.1 Summary

Driver

EnergyAustralia notes that the main driver for this upgrade was expected load growth, which would have prevented its existing network from meeting the modified n-2 planning criteria. The modified n-2 approach allows for a simultaneous outage of cable 41 or 42 and any 132kV feeder or 330/132kV transformer supplying the CBD.

To this extent, EnergyAustralia and TransGrid have demonstrated a need to meet forecast load growth in the CBD. At the time of the 1999-2004 revenue cap decision, independent consultancy reviews were undertaken and found that the increased reliability of the modified n-2 approach is appropriate in the CBD.

However the expenditure undertaken on the solution to meet load growth increased substantially from what EnergyAustralia and TransGrid initially proposed. The information provided to date does not demonstrate that this increase was prudently incurred.

Project proposed by EnergyAustralia in the 1999 submission

EnergyAustralia proposed that $25 million be included in the 1999-2004 revenue cap for the Sydney central connections, the initial stage of the CBD upgrade.

The CBD upgrade was developed in three regulatory categories; TransGrid transmission assets, EnergyAustralia transmission assets and EnergyAustralia distribution assets. EnergyAustralia noted that in its submission to IPART for the 1999 distribution revenue cap it proposed that distribution substations at Taylor Square ($13.5 million) and Broadway ($33.8 million) would be built as part of the CBD upgrade.

Table 3.4 sets out the investment amount that EnergyAustralia and TransGrid proposed for the IPART and ACCC 1999-2004 revenue cap decisions.

Table 3.4 Forecast CBD expenditure for the 1999-2004 revenue cap decisions ($m 2003/04)

	1999/00	**2000/01**	**2001/02**	**2002/03**	**2003/04**	**2004+[3]**	**Total**
Sydney central connections[1]	0.00	0.00	5.00	15.00	5.00	0.00	**25.00**
Broadway substation[2]	0.00	0.60	4.50	4.50	3.90	0.00	**13.50**
Taylor Square[2]	0.00	0.00	0.00	0.00	5.60	28.20	**33.80**
Sub-total	**0.00**	**0.60**	**4.50**	**4.50**	**9.50**	**28.20**	**72.30**

1 Included in the ACCC 1999-2004 revenue cap decision for EnergyAustralia.
2 Included in EnergyAustralia's submission for 1999 IPART decision.
3 Not part of the 1999-2004 regulatory period.

Project included in the 1999 revenue cap decision

The ACCC accepted the prudency of the entire amount of capex EnergyAustralia planned to spend over the 1999-2004 regulatory period, which included the Sydney central connections ($25 million). It did not specifically approve the prudency of the CBD upgrade.

The ACCC understands that IPART did not specifically approve any individual capital projects, rather it allowed an overall distribution capital budget over the regulatory period.

Project actually built

EnergyAustralia is now building a substation at Campbell Street, Surry Hills. It is also building 132 kV connections to TransGrid's new Haymarket substation. The distribution substations at Taylor Square and Broadway were not built. EnergyAustralia informed the ACCC that the transmission substation at Campbell Street replaced the Taylor Square substation and TransGrid's Haymarket substation replaced the proposed Broadway substation. The actual expenditure by TransGrid on this project over the period was $276 million. The draft TransGrid revenue cap decision discusses

TransGrid's portion of the CBD upgrade. EnergyAustralia has provided the following as actual expenditure to date plus forecast expenditure to completion (Table 3.5).

Table 3.5 Actual CBD expenditure ($m 2003/04)

	1999/00	2000/01	2001/02	2002/03	2003/04	2004+[3]	Total
EnergyAustralia's transmission asset[1]	0.00	0.00	15.60	27.10	15.74	4.00	62.3
EnergyAustralia's part of joint tunnel[1]	0.00	0.00	0.00	0.00	5.4	0.00	5.4
EnergyAustralia's transmission sub total	0.00	0.00	14.47	26.31	21.10	4.00	65.88
add: Distribution expenditure[2]	0.00	0.70	3.80	9.60	8.50	4.00	26.6
Total	**0.00**	**0.70**	**19.40**	**36.70**	**29.64**	**8.00**	**94.30**

1. EnergyAustralia's transmission expenditure in the CBD.
2. EnergyAustralia's distribution expenditure in the CBD.
3. Not part of the 2004-2009 regulatory period.

Regulatory test

EnergyAustralia and TransGrid undertook a joint regulatory test assessment of the CBD upgrade in 1999/2000. NERA was engaged to undertake this regulatory test assessment in the first instance. In the initial assessments 14 options were analysed by NERA on the basis of information provided by EnergyAustralia and TransGrid. These included:

- 5 network options
- 2 generation options
- 7 bundled options (including demand side management, network and generation)

EnergyAustralia's component in the NERA analysis included a Surry Hills substation. NERA did not assess alternative sites for this substation.

NERA concluded that all 14 options met the reliability standard for Sydney's CBD. NERA did not conclude that a single option in entirety was least cost. NERA stated that this was discretionary given the sensitivity of the costs to uncertain variables.

Nevertheless, it did conclude that "…options in which the 330kV Haymarket line is commissioned as the first stage of investment, in 2003/04, are the lowest cost, under each of the four scenarios considered". It further concluded that "…the lowest cost investment in the first stage is a network option (option 3)"[20].

NERA's only conclusive recommendation was that the Haymarket 330kV augmentation in 2003/04 was a least cost investment as a first stage. The review undertaken by NERA is inconclusive about the remaining stages of the CBD upgrade as a whole. It recommended further assessment of the later stages as updated information became available. This is consistent with Note 7(a) of the regulatory test which states "… a proposed augmentation must not be determined to satisfy the regulatory test more than 12 months before the start of construction…"[21].

NERA did not verify the network cost details supplied by EnergyAustralia and TransGrid. Nor did it develop additional options that were not suggested to it. Rather it undertook a NPV analysis of the options suggested to it and at the costs supplied.

However, at the time this assessment was undertaken, ACCC staff understood that the public consultation raised various issues that were considered in the final regulatory test. For example, Ewbank Preece[22] noted that, by international standards, the cable costs were underestimated by approximately 40 per cent. It further recommended that TransGrid and EnergyAustralia go to the market for firm cable costs.

NERA opted for a 40 per cent sensitivity analysis across the network options to account for Ewbank Preece's concerns.

In their final report on the regulatory test EnergyAustralia and TransGrid recommended that:

- TransGrid commission the 132kV part of the Haymarket 330/132kV substation by March 2003
- EnergyAustralia progressively connect its 132kV system to the Haymarket 132kV busbar from March 2003
- EnergyAustralia commission a 132kV busbar at a new 132/11kV zone substation in Surry Hills by July 2003
- TransGrid commission a 330/132kV Haymarket substation by October 2003
- TransGrid commission a 330kV underground cable from Sydney South 330/132kV substation to the new Haymarket 330/132kV substation by October 2003

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[20] NERA, *Supply to Sydney CBD and Inner Suburbs*, February 2000.

[21] Supra footnote 8, p.27.

[22] Ewbank Preece Pty Ltd, *Review of Proposed Augmentation of Supply to the Sydney CBD Final Report*, April 1999.

- TransGrid commission 330kV cable bays and associated works at Sydney South 330/132kV substation to connect the 330 kV underground cable by October 2003.

EnergyAustralia's 2003 application

As part of its application EnergyAustralia submitted an SKM report on the prudency of its past capital spend. SKM's review was limited to reviewing the timing of the capex and the cost of the assets built. SKM did not review the alternative options that may have resulted in a lower cost solution.

SKM noted that the capex program had prudent timing and that some costs seemed high given the scope of the work.

SKM noted that EnergyAustralia's transmission part of the CBD upgrade involved building:

- a 132/11kV substation in Surry Hills. The location chosen is Campbell Street after Goulbourn Lane was unsuccessful ($8 million for additional land). SKM notes a cost of $33.75 million

- a 132kV connection between the new Campbell Street substation and TransGrid's Haymarket 330/132kV substation. SKM notes a cost of $53.05 million.

SKM notes a total estimated cost of $94.8 million, which includes the distribution component.

SKM concluded that the timing and cost of this project were prudent and appropriate, on the basis that NERA and IPART had undertaken a review of this project. This is of concern because the actual cost of the project has risen substantially since the NERA review.

The ACCC questions SKM's conclusions that EnergyAustralia had chosen the most prudent and efficient option without its own examination of the alternatives and the costs and benefits associated with the alternatives.

Consultant's report

While GHD notes that the regulatory test process was well documented by EnergyAustralia, it also noted the analysis that lead to the altered final investment decision was not. GHD did not conclude that the entire project was prudent and efficient.

GHD concluded that no matter which overall option was selected under the regulatory test review, EnergyAustralia's component would still have had to establish a zone substation in the Surry Hills area.

It noted that, since the regulatory test was undertaken, there have been various design changes, which resulted in increased project costs. GHD stated that it was unable to trace these cost increases from what the ACCC initially allowed to the amount that satisfied the regulatory test and finally to the amount actually spent on the CBD upgrade.

ACCC considerations

The ACCC considers that EnergyAustralia has justified parts of the CBD project. EnergyAustralia has provided detailed explanations of how and where network deficiencies would arise if the CBD upgrade was not undertaken. Therefore, the ACCC considers that the need for a prudent investment has been justified.

Furthermore, the ACCC agrees that under the regulatory test EnergyAustralia's capex would have only increased had another option been selected. Hence, there is justification to allow the costs examined under the regulatory test.

The ACCC agrees with GHD that there are concerns with the actual investment undertaken because of the significant increase in costs. To review this increase, the ACCC needs to understand the costs on which EnergyAustralia's component, under the regulatory test report, was estimated. To date, this information has not been forthcoming from EnergyAustralia.

Only once the detailed scope of the project and associated costs are established can the ACCC trace EnergyAustralia's process as the costs were increasing. This information will give the ACCC a basis to determine the prudency of the actual investment that was made.

While the ACCC does not understand the full details of the cost increase, it is aware that the following items contributed to the increase.

- Locating and acquiring an appropriate site in the Surry Hills area.
- The method of undergrounding through the CBD.
- Additional feeder bays.

EnergyAustralia has explained that these increases occurred; however, the measures it used to prevent or to mitigate these cost increases remain unexplained. The ACCC could determine that the full cost of this project was not prudent if a prudent business, acting efficiently, could have avoided or minimised these costs.

The ACCC has not questioned the rigour of NERA's initial regulatory test analysis in this draft decision. However, it notes that the magnitude of the cost increase that occurred on this project is significant enough to justify a review of the level of detail used in the initial regulatory test. This would need to be undertaken for all options under the regulatory test not just the selected one. Regardless, this type of analysis is unlikely to have affected what EnergyAustralia would have had to build at that stage.

EnergyAustralia has not reconciled the actual cost to the estimate used in the regulatory test however the ACCC has a high level understanding of what these costs were. The ACCC considers that EnergyAustralia has not shown that its decision to spend more than the regulatory test forecast was prudent. EnergyAustralia has not explained on what basis this increased expenditure was made or what it did to minimise the actual costs.

Consistent with the draft TransGrid revenue cap decision (chapter 4, section 4.6.1), the ACCC will disallow any return on EnergyAustralia's investment in the CBD upgrade during the period of construction for the draft decision. Adopting this approach would mean reducing the carried forward value of this project by $8.7 million or 14 per cent. The equivalent reduction in the draft TransGrid revenue cap decision is 16 per cent. The ACCC has followed the same methodology in calculating the two figures. The difference between the two is that EnergyAustralia and TransGrid's timing of expenditure on the project differs; hence the disallowed rate of return during construction also differs.

3.11 Feeders 910 and 911

3.11.1 Summary

EnergyAustralia proposed that $10 million be included in the 1999-2004 revenue cap to increase the rating of feeders 910 and 911 running from Sydney South to Chullora. The ACCC accepted the initial prudency of this project and included an allowance of $10 million in the 1999-2004 revenue cap decision. This project was completed in October 2001 at a cost of $5.1 million.

As part of this project, EnergyAustralia replaced the conductors on about 15 kilometres of double circuit transmission line and undertook the structural reinforcement of towers. It provides an additional 100 megawatt (MW) of capacity during normal system conditions, rising to 160 MW when TransGrid's 330 kV cable from Sydney South to Beaconsfield (cable 41) is out of service.

This project is an augmentation to the network. EnergyAustralia states that the main driver for this project was the loading on the interconnected system supplying the CBD. EnergyAustralia states that this project assisted in deferring expenditure on a new 330 kV supply point into the CBD.

EnergyAustralia utilised an n-1 reliability criterion in its planning for this project. With cable 41 out of service the loading on feeders 910 and 911 exceeds their firm capacity.

In its initial planning stage for this project, EnergyAustralia identified three options to address the loading issues on the Beaconsfield West substation. EnergyAustralia identified the up rating of feeders 910 and 911 as the most cost effective solution.

3.11.2 Consultant's report

On the basis of the load flow data and loading details provided by EnergyAustralia, GHD concluded that the issues identified in relation to the relief of Beaconsfield West and ultimately supply to the CBD are valid and that technically the project was an appropriate option to address those issues.

GHD also concluded that the option of replacing conductors on feeders 910 and 911 appears to be prudent from a technical perspective and that the project provided a cost effective option for the deferral of expenditure by TransGrid.

GHD could not conclude that the investment as a whole was prudent because it had not been provided by EnergyAustralia with sufficient information on the costings for this project compared to other options considered.

3.11.3 ACCC's considerations

The ACCC notes that the actual cost of the project was substantially below that originally forecast and allowed for in the 1999-2004 revenue cap decision. EnergyAustralia has stated that the lower cost for this project was the result of a competitive tendering process.

As noted above, GHD were unable to conclude that the investment as a whole was prudent because it had not been provided with sufficient information on the costings for this project and other options considered. EnergyAustralia has since submitted additional details on the costing of this project to the ACCC.

Based on the additional information provided, the ACCC considers that this project is a prudent investment and hence $5.1 million has been included in the opening RAB in relation to this project.

3.12 Tuggerah to Munmorah feeder

3.12.1 Summary

EnergyAustralia proposed that $3.5 million be included in the 1999-2004 revenue cap for a feeder between Tuggerah and Munmorah. The ACCC accepted the initial prudency of the feeder between Tuggerah and Munmorah and included an allowance of $3.5 million in the 1999-2004 revenue cap decision. The feeder was completed in 2001 at a cost of $4 million.

While not included in the ACCC's 1999-2004 revenue cap decision, a related project is the construction of two substations at Wyong and Charmhaven which are connected to the new feeder from Tuggerah to Munmorah. EnergyAustralia states that $18 million was included for the construction of the two substations in EnergyAustralia's distribution capital allowance as part of IPART's 1999 determination. The conversion of the two zone substations was also completed in 2001 and cost approximately $20 million.

The Wyong and Charmhaven substations are two of the assets that EnergyAustralia is claiming to now meet the code definition of transmission assets and is seeking to include in the transmission RAB (for more details see section 3.6 above). While the construction of these two substations was analysed as part of the review of the feeder from Tuggerah to Munmorah, the discussion below mainly refers to the feeder project.

Tuggerah to Munmorah feeder

The feeder is an augmentation to the network which EnergyAustralia states was required to overcome excess electricity loads and improve system reliability in the Wyong and Charmhaven area. EnergyAustralia states that this project was required to improve reliability, reduce network losses, retire aging assets and cater for high demand growth. The peak loading on the existing 33 kV system was in excess of firm ratings and there was a risk of load shedding for any equipment failure. EnergyAustralia adopted an n-1 reliability planning criterion for the feeder augmentation.

Construction of Charmhaven and Wyong zone substations

The construction of the two substations is an augmentation to the network. EnergyAustralia states that the major drivers for the project were the loadings on:

- the Charmhaven zone substation, which exceeded its firm capacity by 1996
- the Wyong zone substation, which exceeded its firm capacity by 2000.

As with all zone substations, EnergyAustralia utilises an n-1 planning criterion and risk analysis to determine when an augmentation is required. In the case of the Charmhaven and Wyong zone substations, a risk assessment allowed this project to be deferred until 2001, including the construction of the feeder.

EnergyAustralia also states that the entire project provided for the deferral of approximately $22 million in expenditure by TransGrid. This deferral, but not cost, is stated in the joint EnergyAustralia and TransGrid regulatory test.[23]

In its initial planning stage, EnergyAustralia identified a number of potential options to address the loading issues in the Wyong and Charmhaven area. EnergyAustralia states that on a least cost basis, the chosen option was substantially cheaper. EnergyAustralia states that it has analysed non-network solutions including demand management but these were not viable.

3.12.2 Consultant's report

GHD has reviewed the information provided by EnergyAustralia and concluded that:

- the forecast loads exceeded firm ratings at the Wyong and Charmhaven zone substations
- loadings on the interconnected systems and bulk supply points support the justification for the conversion of the Charmhaven zone substation to 132 kV
- the 132 kV interconnection between Tuggerah and Munmorah was a strategic solution to providing relief to the Munmorah bulk supply point and Ourimbah sub-transmission substation.

GHD is unable to determine if the magnitude of the investment was prudent due to a lack of information on how the costs of the project moved from its initial planning stage to board approval and ultimately the 1999 submission to the ACCC. GHD noted that the final cost of the feeder from Tuggerah to Munmorah exceeded the ACCC allowance by approximately 10 per cent.

Overall, GHD concluded that there was a need for a solution to address the load constraints identified by EnergyAustralia and that the project built will address that

[23] EnergyAustralia and TransGrid, *Development of Electricity Supply to the Central Coast Final Report*, March 2003.

need, however GHD was unable to determine if the magnitude of the expenditure was prudent due to a lack of information.

3.12.3 ACCC's considerations

Consistent with the 1999-2004 revenue cap decision, the ACCC has reviewed the reasonableness of EnergyAustralia's actual expenditure on this project. As stated above, the actual cost of the feeder exceeded that allowed in the 1999-2004 revenue cap decision by approximately $0.5 million. EnergyAustralia has advised the ACCC that this overspend was the result of delays in gaining environmental impact statement approval, and construction and final design issues which meant major construction did not commence until 2001.

The ACCC accepts GHD's findings that the need for this project has been demonstrated. As noted above, GHD were unable to conclude that the investment as a whole was prudent because it had not been provided with sufficient information on the costings for this project and other options considered. EnergyAustralia has since submitted additional details on the costing of this project to the ACCC.

Based on this additional information, the ACCC considers that this project is a prudent investment and hence $4 million has been included in the opening RAB in relation to this project.

With regard to the two zone substations at Wyong and Charmhaven, their full value will be rolled into the opening RAB at 1 July 2004. See section 3.6 for more details.

3.13 Macquarie Park substation

3.13.1 Summary

The Macquarie Park substation project was not included in EnergyAustralia's submission to the ACCC in 1999. However, EnergyAustralia states that the construction of a zone substation was included in its 1997 distribution application to IPART and that an allowance of $10 million was provided for the construction of a new 132/11kV zone substation at Macquarie Park in 2004/05. The Macquarie Park zone substation was completed in 2001 at a cost of $11.6 million.

This project is an augmentation to the network. EnergyAustralia states that this project was required to accommodate significant load growth in the Macquarie Park area during the 1999-2004 regulatory period. In particular, the loadings on the Epping and North Ryde zone substations exceeded their firm capacities by the summer of 2000.

EnergyAustralia utilised an n-1 planning criterion for this zone substation. However, if a zone substation is loaded above its firm rating, EnergyAustralia carries out a risk assessment to determine whether augmentation is required or can be deferred. The risk management approach employs the criteria that development work is only undertaken if the firm rating of the substation is forecast to be exceeded more than one per cent of the time or the annual probability of failure(s) which require load shedding to prevent equipment damage exceeds one per cent.

For the Epping and North Ryde zone substations, EnergyAustralia conducted risk assessments for summer 2000 and 2001. Both substations exceeded the risk assessment criteria for the summer of 2001. Therefore, EnergyAustralia brought forward the completion of the project from 2004/05.

EnergyAustralia contends that the earlier completion of the project was due to ongoing high load growth and two specific projects:

- the Parramatta to Chatswood rail link
- connecting Exodus, a data warehouse company, to the network.

EnergyAustralia states that it has instigated demand management initiatives via an expression of interest which, given the load growth forecast at the time, identified some practical options that would have provided for a short deferral of the project. However, the high energy usage of the forecast projects outstripped the capability of the identified demand management alternatives.

3.13.2 Consultant's report

GHD concludes that EnergyAustralia has demonstrated the technical justification for the project including:

- the proximity of the site to existing 132 kV lines
- load growth in the area and
- that a standard 132/11 kV zone substation would have an ultimate capacity to accommodate the forecast loads, compared with 33/11 kV or 66/11 kV design.

However, GHD is unable to reach a conclusion on the prudency of the project as it has not been provided with any detailed information on project costings and the analysis of options considered to meet the need.

3.13.3 ACCC's considerations

The ACCC has been provided with the VM study for this project which was conducted in September 1998 and recommended, as its preferred option, a new substation being commissioned in Macquarie Park in 2005. EnergyAustralia has also provided risk assessments which demonstrate that the substations at Epping and North Ryde exceeded risk assessment criteria. The ACCC has been provided with a demand management paper for the area and a project brief with high level cost estimates.

While EnergyAustralia has verbally explained that the project was brought forward from 2005 to 2001 as a result of the Parramatta to Chatswood rail link and Exodus, the information provided to the ACCC to support this has been limited. The ACCC has been provided with a request for quotation from the builders of the rail link in August 2002 which outlined a request for high voltage power. The ACCC has not been provided with documentation, from prior to construction which verifies the forecast loads from the rail link and Exodus, which underpinned EnergyAustralia's decision to bring forward the construction of the Macquarie Park substation.

As this project was not included in the 1999-2004 revenue cap decision, and in the absence of any regulatory test (or similar) assessment, the ACCC has endeavoured to utilise the following principles in determining the efficiency of the project.

- Was the project required?
- Were the timing and costs appropriate?
- Was the option that was built, the most efficient means to address the problem?

The ACCC concurs with GHD's assessment that EnergyAustralia has provided technical justification of a problem on its network.

The ACCC has determined that the cost of the substation appears reasonable.

However, the ACCC has not been provided with a regulatory test application or any other economic analysis which demonstrates that the Macquarie Park zone substation was the most efficient option to address the issues in the area. Rather, the only analysis EnergyAustralia has provided to the ACCC on the options considered in meeting this need was the planning study conducted in 1998 which utilised preliminary figures assuming a 2004/05 commissioning date.

A project such as this would only satisfy the regulatory test or the prudency test if it was the least cost project to address the network limitation that had been identified. Consistent with the requirements of the code, the ACCC does not believe that an investment should be rolled into the RAB unless it is satisfied that this is the case.

As outlined in the introduction of this chapter, the ACCC is relying on EnergyAustralia to submit information which demonstrated that this project was an efficient investment. While this information has been requested by the ACCC, it has not been forthcoming. Without this information, the ACCC does not have an evidentiary basis upon which it can be satisfied that the full cost of this investment was prudent or efficient. Therefore, due to a lack of information from EnergyAustralia and the lack of economic analysis of the options considered, the ACCC, like GHD, is unable to conclude that the full cost of the Macquarie Park substation project is an efficient investment.

As it is unable to confidently identify an efficient level of expenditure the ACCC proposes to disallow any return on EnergyAustralia's investment in the Macquarie Park substation during the period of construction for the draft decision. This amounts to a \$3 million or 26 per cent reduction to the carried forward value of this project. See section 3.20 for a discussion on how the ACCC determined this reduction.

3.14 Beresfield substation

3.14.1 Summary

The construction of a new 132/33kV sub-transmission substation at Beresfield commenced in the 1999-2004 regulatory period. However, the project will not be completed until part way through the 2004-2009 regulatory period. Details on this project can be found in the future capex chapter.

3.14.2 ACCC's considerations

The ACCC has not been provided a regulatory test application which demonstrates that the Beresfield sub-transmission substation was the most efficient option to address the issues in the area. Rather, the only analysis EnergyAustralia has provided to the ACCC on the options considered in meeting this need are outlined in a number of internal planning reports. The planning reports do not provide sufficient details on the costings of all the options identified as per the regulatory test principles. EnergyAustralia also failed to publicly consult on this project to ascertain if any further options to address this need were available.

As outlined in the introduction and in section 3.13.3 of this chapter, the ACCC is relying on EnergyAustralia to submit information which demonstrated that this project was an efficient investment. While the ACCC has requested this information it has not been provided. Therefore, due to a lack of information from EnergyAustralia and the lack of economic analysis of the options considered, the ACCC, like GHD, is unable to conclude that the Beresfield sub-transmission substation project is an efficient investment.

As it is unable to confidently identify an efficient level of expenditure the ACCC proposes to disallow any return on EnergyAustralia's investment in the Beresfield substation during the period of construction for the draft decision. This amounts to a $0.4 million or 5 per cent reduction to the carried forward value of this project. See section 3.20 for a discussion on how the ACCC determined this reduction.

3.15 Undergrounding transmission mains at Homebush

3.15.1 Summary

The undergrounding of transmission mains at Homebush was not included in the 1999-2004 revenue cap decision. EnergyAustralia states that its component of the costs of this project was $10 million.

The ACCC has been provided with an extract of an implementation agreement between the Olympic Co-Ordination Authority (OCA) and EnergyAustralia for the relocation of an overhead transmission system and the construction of an underground transmission system in the Homebush Bay Development area. EnergyAustralia has also provided a construction contract for this project with a total cost of $37 million. EnergyAustralia states that it contributed $10 million to this project with the remainder paid by the Sydney Organising Committee for the Olympic Games and the OCA.

3.15.2 Consultant's report

GHD was not asked to review this project.

3.15.3 ACCC's considerations

EnergyAustralia has not provided a VM study or any other information which explains why this project was required and the options considered.

While the ACCC has been provided with an extract of an implementation agreement between OCA and EnergyAustralia, EnergyAustralia has not explained the statutory powers which gave the OCA the right to direct EnergyAustralia to construct an underground transmission system. EnergyAustralia has also not explained what assets it was instructed to build and decommission.

Furthermore, the ACCC is unable to determine, on the information provided to date, what specific assets have been built as part of this project and what specific assets relate to the $10 million being claimed as transmission capex by EnergyAustralia.

Therefore, the ACCC is unable to determine whether this was an efficient investment due to insufficient information as to:

- why this project was required
- the specific assets built
- what specific assets comprised the $10 million claimed to have been EnergyAustralia’s expenditure
- why EnergyAustralia contributed $10 million
- any economic analysis which demonstrates that this project was the least cost option to address the need.

Unlike the projects discussed above, EnergyAustralia has failed to provide sufficient information to demonstrate that this project was required. Therefore, the ACCC considers that consumers should not pay for this investment and the ACCC has determined that it will exclude this project from the opening RAB. EnergyAustralia does have the opportunity to provide the information required by the ACCC prior to the ACCC making its final decision.

3.16 Green Square substation

3.16.1 Summary

The construction of a new 132/11kV zone substation at Green Square commenced in the 1999-2004 regulatory period. However, the project will not be completed until part way through the 2004-2009 regulatory period. Details on this project can be found in the future capex chapter.

3.16.2 ACCC’s considerations

While there are a small number of outstanding issues with this project, overall the ACCC considers that the Green Square project is an efficient investment. Therefore, with regard to the costs already incurred for this project the ACCC has included $4.2 million in the opening RAB.

3.17 Replacement and refurbishment program

3.17.1 Summary

The ACCC allowed $32.6 million in the 1999-2004 revenue cap decision for replacement of transmission mains and substations. EnergyAustralia has spent $10.5 million over the 1999-2004 regulatory period on its general replacement and refurbishment program resulting in an underspend of approximately $22 million.

3.17.2 Consultant's report

GHD concluded that insufficient information was provided on these items to enable any reasonable conclusions to be drawn on the efficiency of the replacement and refurbishment program.

3.17.3 ACCC's considerations

The ACCC considers that EnergyAustralia's actual expenditure appears appropriate and has retained $10.5 million in the asset base for EnergyAustralia's past capex for its general replacement and refurbishment program, and oil containment and environment programs.

3.18 Non-system capex

3.18.1 Summary

The 1999-2004 revenue cap decision did not include an allowance for non-system capex. EnergyAustralia has spent nearly $19 million on non-system capex during the 1999-2004 regulatory period. Non-system capex includes expenditure on: IT systems; vehicles and plant; office equipment; and land and buildings.

3.18.2 Consultant's report

GHD was not asked to review this expenditure.

3.18.3 ACCC's considerations

The ACCC considers that EnergyAustralia's expenditure appears appropriate and has included $19 million in the asset base in respect of EnergyAustralia's non-system capex over the 1999-2004 regulatory period.

3.19 Gosford to Ourimbah feeder

3.19.1 Summary

EnergyAustralia proposed that $7 million be included in the 1999-2004 revenue cap to construct a feeder between Gosford and Ourimbah. The ACCC accepted the initial prudency of this project and included an allowance of $7 million in the 1999-2004 revenue cap decision. The construction of the feeder has commenced but is yet to be completed. It is now estimated to cost around $12 million. EnergyAustralia has not provided an explanation of these cost overruns.

While not included in the ACCC's 1999-2004 revenue cap decision, a related project is the conversion of the West Gosford zone substation which is connected to the Gosford to Ourimbah feeder. EnergyAustralia states that around $9.5 million was included in EnergyAustralia's distribution capital allowance as part of IPART's 1999 determination for the conversion of the Lisarow zone substation. This was subsequently changed to the conversion of the West Gosford zone substation. The conversion of the West Gosford zone substation has commenced but is also yet to be completed. It is now estimated to cost around $12 million. EnergyAustralia has not provided an explanation of these cost overruns.

3.19.2 Consultant's report

GHD was not asked to review this project.

3.19.3 ACCC's considerations

EnergyAustralia has informed the ACCC that at the time of its application to the ACCC in 1999 this project was classified as being a transmission project. However, subsequent to the 1999-2004 revenue cap decision being made it was realised that the feeder connected two parts of EnergyAustralia's distribution network. Hence, the feeder should not have been included in the 1999-2004 revenue cap decision as a transmission project and it was subsequently excluded from the ACCC's regulatory accounts and included in IPART's regulatory accounts.

Over the course of the 1999-2004 regulatory period, the configuration of EnergyAustralia's network on the central coast has changed. As a result, the Ourimbah to Gosford feeder and the West Gosford zone substation now meet the definition of transmission assets. The Gosford to Ourimbah feeder and the West Gosford zone substation are two of the assets changing classification from 1 July 2004, see section 3.6 above.

Both of these projects were included in 1999-2004 transmission and distribution decisions. Therefore, both the ACCC and IPART accepted the initial prudency of the projects.

The ACCC considers that these investments appear to be prudent but is reserving its judgement until EnergyAustralia is able to adequately explain its cost overruns. For the purposes of the draft decision the ACCC has provisionally allowed the total actual expenditure to date to be rolled into the opening RAB; however, in finalising its decision it will be seeking information from EnergyAustralia to justify the final costs of the feeder and substation.

3.20 ACCC's draft decision

The ACCC does not believe that EnergyAustralia has demonstrated that the ODRC valuation conducted in 1999 is materially affected by error. Despite a request from the ACCC, EnergyAustralia has not provided a full list of these errors and their order of magnitude. Furthermore, EnergyAustralia has not provided details on the alleged inconsistencies between the 1999 ODRC valuations for TransGrid and EnergyAustralia that it claims should be taken into account when establishing the RAB. Finally, the ACCC is unable to determine whether all of EnergyAustralia's past capex is efficient and hence does not accept the values included in EnergyAustralia's proposed 2004 ODRC valuation.

For the reasons set out above:

- the ACCC does not believe a revaluation of the RAB is justified
- the ACCC instead proposes to adopt a roll-forward methodology in determining an opening RAB for the 2004-2009 regulatory period.

With regard to the number of assets changing classification from distribution to transmission from 1 July 2004, the ACCC's draft decision is that these assets now meet the code definition of transmission assets and the transmission opening RAB will be increased by $90.4 million with a corresponding reduction in the distribution RAB.

As outlined above, EnergyAustralia spent considerably more on capex in the 1999-2004 regulatory period than forecast at the time of the decision. The ACCC considers that the burden to explain and justify this overspend rests with EnergyAustralia.

The ACCC has sought information from EnergyAustralia to demonstrate that its past capex was efficient. The information EnergyAustralia provided has focused on demonstrating the problems and issues on its network that led to a network solution. With the exception of the undergrounding of transmission mains at Homebush, the information provided on these issues has generally been sufficient.

However, the ACCC considers that EnergyAustralia has generally failed to provide the economic analysis of options to demonstrate that the options it chose were the most efficient means of addressing the problems on its network.

GHD was also unsuccessful in their attempts to attain from EnergyAustralia a robust economic analysis of options it considered when developing its past capital projects, and as a result were often unable to reach conclusions on the efficiency of EnergyAustralia's past capex.

Submissions from interested parties highlighted the lack of information on past capex provided in EnergyAustralia's application. This lack of information limited interested parties' ability to evaluate past capex.

EnergyAustralia's submission criticised GHD's report, in particular, the lack of conclusions with regard to the prudency of EnergyAustralia's past and future capex. EnergyAustralia contends that the inconclusive nature of the report was driven by a constrained process and a lack of clear methodology by GHD.

EnergyAustralia did provide a prudency report by SKM which included a number of transmission projects. While this report assesses and ultimately concludes that the timing and magnitude of EnergyAustralia's investments were prudent, it did not specifically review the evaluation of the range of augmentation options considered to determine that the lowest cost option was chosen, nor did it determine if all available options had been considered. Given that only two projects (the Sydney CBD upgrade and Green Square) have been subjected to the regulatory test, a review of the consideration of options would seem to be necessary before it could be concluded with confidence that the full cost of the projects being reviewed was prudent and efficient for the purposes of the code.

Therefore, the ACCC questions parts of the prudency assessment within the SKM report. Project timing and cost is one part of an economic analysis, the other significant components are that all feasible options were considered when building the project and that the least cost option out of those was the project implemented.

Such an analysis is set out in the principles of the regulatory test. The appraisal of options and the regulatory test are supposed to be part of EnergyAustralia's internal capital project approval process. However, the ACCC has been provided with only limited information on this component of EnergyAustralia's internal processes. In general, EnergyAustralia has provided VM studies for each past capex project but has not provided documentation which demonstrates how the initial options identified in the VM study are developed into business cases and what ultimately goes to the board for approval. EnergyAustralia has only provided brief explanations of what the board approved for each past project.

The ACCC has reviewed the efficiency of the projects EnergyAustralia has built or commenced building in the 1999-2004 regulatory period. For the projects included in the 1999-2004 revenue cap decision, the ACCC's draft decision is that these projects are prudent investments and will be rolled into the RAB at their actual cost.

For projects not included in the 1999-2004 revenue cap decision, the ACCC sought regulatory test applications or any other economic analysis of the options considered by EnergyAustralia which demonstrated that the option chosen was the most efficient means of addressing the need. Apart from the CBD project and the Green Square substation, this has not been provided.

Where EnergyAustralia has demonstrated that its capex projects are efficient, the ACCC's draft decision is to allow the full costs of the project to be rolled into the opening RAB. Therefore, the ACCC will allow the full cost of the Green Square project, replacement and refurbishment program and non-system capex into the opening RAB. The ACCC will also allow the foregone rate of return on this efficient investment to be rolled into the opening RAB at the WACC rate of return.

For the undergrounding transmission mains at Homebush, the ACCC determined that EnergyAustralia has failed to demonstrate that this project was needed. Therefore, the ACCC's draft decision is to not roll this project into the opening RAB.

For the CBD project, the ACCC has determined EnergyAustralia was prudent in undertaking the regulatory test and that, if the investment had occurred as planned then it would have been deemed prudent. However, it has also determined that the entire cost of the upgrade is not necessarily prudent because of the cost increases.

Without a demonstration that EnergyAustralia was prudent in incurring these cost increases the ACCC will not roll the entire spend of $62 million into the RAB for the final revenue cap decision. Therefore, consistent with the draft TransGrid revenue cap decision the ACCC will disallow any return on EnergyAustralia's investment in the CBD upgrade during the period of construction for the draft decision. This amounts to a $8.7 million or 14 per cent reduction to the carried forward value of this project.

For the remaining projects, the ACCC considers that EnergyAustralia has failed to provide sufficient information to demonstrate that these projects were efficient investments. Without sufficient information the ACCC is unable to ascertain an efficient level of expenditure for these projects; therefore, the ACCC's draft decision is to also disallow any return on EnergyAustralia's investment in these projects during the period of construction for the draft decision.

Disallowing a return on EnergyAustralia's investment in these projects during the period of construction reflects a balance between fully rejecting that component of the RAB about which the ACCC considers EnergyAustralia has not demonstrated to be efficient and prudent, and recognising the need for TNSPs to invest in their networks. Given the ACCC is unable to determine that all of EnergyAustralia's past capex is efficient, the ACCC considers that consumers should not be required to pay for the full investment.

While the ACCC has not been able to satisfy itself that the amount actually spent on certain projects was prudent, it does not necessarily follow that these investments should be excluded in their entirety. Even if EnergyAustralia should have identified and implemented an alternative option, there would still obviously be some capital cost to EnergyAustralia in doing so. The problem facing the ACCC is that, given the inadequacy of the information provided by EnergyAustralia, there is no exact basis for determining precisely how much it should have spent. The ACCC is therefore forced to adopt a different approach. Reasons for this approach are set out in chapter 4 of the draft TransGrid revenue cap decision.

With respect to past capex, the ACCC's draft decision is to allow $125 million to be rolled into the opening RAB, including the foregone rate of return.

The ACCC's draft decision is that the opening RAB for the 2004-2009 regulatory period is $628.6 million. The RAB calculations are set out below in Table 3.6. This is a substantial increase of approximately 37 per cent on the opening RAB for the 1999-2004 revenue cap. This increase is the result of:

- a considerable overspend on the capital allowance included in the 1999-2004 revenue cap decision
- assets changing classification. The impact of the assets changing classification contributes 53 per cent to the increase in the opening RAB and excluding its impact would result in an increase of only 18 per cent.

Table 3.6 EnergyAustralia's RAB ($m nominal)

	1999/00	2000/01	2001/02	2002/03	2003/04
Opening asset base	457.4	450.7	462.6	470.3	469.7
Decision capex at actual CPI	3.4	9.2	19.5	9.9	15.9
CPI adjustment	12.8	27.0	13.6	16.2	10.6
Depreciation[1]	-22.8	-24.3	-25.4	-26.7	-25.2
Closing asset base	450.7	462.6	470.3	469.7	471.0
add: capex not forecast over 1999-2004					67.1
add: assets changing classification over 1999-2004					90.4
Opening RAB 1 July 2004					**628.6**

Note: Numbers may not add due to rounding
1. Adjusted for actual inflation.

The roll forward methodology adopted by the ACCC in its modelling of the revenue cap means the closing balance of the asset base for one year becomes the opening balance for the subsequent year. It should be noted that the 2003/04 figures for capex projects above are only forecasts at the time of this draft decision. In finalising its decision, the ACCC will update these to include actual expenditure.

4. Forecast capital expenditure

4.1 Introduction

The ACCC needs to value EnergyAustralia's future capex in order to set an appropriate maximum allowed revenue. In this regard the ACCC released a discussion paper that proposes an ex-ante approach to setting a future capex allowance. EnergyAustralia has been receptive to this idea and has provided its 'in principle' support to exploring this approach.

EnergyAustralia needs to resubmit its capex proposal in accordance with the principles of the proposed ex-ante approach.

The basic principle behind the ex-ante approach is for the ACCC to determine a fixed allowance for capex to be rolled into the future RAB. This removes the need for an ex-post review of capex, provides TNSPs with certainty in making investment decisions, and allows customers to have a better expectation of future pricing.

In addition to the increased certainty the ACCC considers that this approach will provide stronger incentives to ensure only efficient capex decisions are made. The remainder of this chapter discusses this proposed capex approach and:

- the code requirements pertinent to this revenue cap (section 4.2)
- the ACCC's current approach to assessing future capex (section 4.3)
- the ACCC's proposed ex-ante approach (section 4.4)
- EnergyAustralia's initial application (section 4.5)
- the implications for EnergyAustralia's revenue cap (section 4.6)
- discussion of the information provided to date (section 4.7)
- EnergyAustralia's capital governance framework (section 4.8)
- EnergyAustralia's replacement and refurbishment (section 4.9)
- discussion of expenditure as spent versus as commissioned (section 4.10)
- the ACCC's draft decision and remaining consultation process (section 4.11).

4.2 Code requirements

The ACCC's task in assessing EnergyAustralia's forward capex is set out in the code. In particular, part B of chapter 6 of the code requires that:

- in setting the revenue cap the ACCC must have regard to the potential for efficiency gains in expected operating, maintenance and capital costs, taking into account the expected demand growth and service standards

- the regulatory regime must seek to achieve efficiency in the use of existing infrastructure, efficient operating and maintenance practices and an efficient level of investment

- the regulatory regime must foster an efficient level of investment within the transmission sector and the sectors upstream and downstream of it.

4.3 The ACCC's current ex-post capex approach

On 1 July 1999 the ACCC assumed the responsibility for the regulation of transmission revenues and it progressively set revenue caps for all TNSPs in the NEM. The revenue caps for EnergyAustralia and TransGrid are the first 'second round' revenue caps.

The DRP outlined the principles that the ACCC intended to apply when setting transmission revenue caps. The DRP explained that an ex-ante forecast of capital expenditure would be used to determine a path of revenues and prices over the regulatory period.

It also stated that only prudent and efficient capex that took place in the previous regulatory period would be rolled into the opening RAB. This assessment would be undertaken at the start of the following regulatory period as an ex-post review. This would be done to set the opening RAB for the new regulatory period.

The DRP states that where a project was forecast in the initial revenue cap and was actually built at or under budget the ex-post review would be limited. Also it stated that a more rigorous ex-post review would be required for those projects that were not forecast or were built at higher a cost than forecast.

Chapter 3 of this draft decision is an example of this type of ex-post review.

The ex-post approach has been found to have its limitations, which are discussed in the draft TransGrid revenue cap decision.

4.4 The proposed ex-ante capex approach

The ACCC is presently considering an alternative approach to transmission investment regulation through the potential introduction of a firm ex-ante investment cap. This approach would involve a TNSP proposing a five-year capex allowance, which would be assessed by the ACCC. The ACCC would establish a firm cap at the start of each regulatory control period.

TNSP's would then be free to prioritise their expenditure within this cap to provide transmission services under the code. In the event that a TNSP invested at a level higher than the cap, the additional investment would not be included in its regulated asset base. There would be no ex-post optimisation of TNSPs' investments under the cap. Provided that the aggregate cost of a TNSP's investments was less than the cap, there would be no risk that the regulator would assess the prudency of the TNSP's investments at the end of the regulatory period.

There are several issues associated with an ex-ante approach including what investments will fall under the cap and what exceptions should be made. The ACCC released a discussion paper[24] on the issues surrounding the ex-ante approach and has called for interested parties to make submissions on the proposal.

4.5 EnergyAustralia's application

On the basis of the existing regulatory principles, EnergyAustralia made its initial application to the ACCC on 23 September 2003. Since that time the ACCC and its consultants have requested various information and EnergyAustralia has made amendments to its application.

EnergyAustralia has informed the ACCC that some transmission investment had been incorrectly included in its submission to IPART. After correcting this, EnergyAustralia's application regarding forecast transmission capex was $183.8 million over the 2004-2009 regulatory period. This included $156 million on system capex and $28 million on non-system capex. The system capex included $89.5 million replacement capex and $66.6 million growth driven capex.

The proposed 2004-2009 capex program represents a real increase of $122.5 million on the capex allowed in the 1999-2004 regulatory period. However, due to EnergyAustralia spending more than forecast over the 1999-2004 regulatory period, its proposed capex is only a real increase of $37.3 million on EnergyAustralia's actual expenditure.

Table 4.1 summarises EnergyAustralia's proposed capex for the 2004-2009 regulatory period.

[24] ACCC, *Review of the Draft Statement of Principles for the Regulation of Transmission Revenues, Supplementary Discussion Paper: Capital Expenditure Framework*, 10 March 2003.

Table 4.1 EnergyAustralia's proposed demand driven capex ($m 2003/04)

	2004/05	2005/06	2006/07	200708	2008/09	Total
Growth driven expenditure						
Lower Hunter 132kV capacity	5.1	3.9	1.0	0.5	0.0	10.5
Beresfield substation	12.6	0.6	0.0	0.0	0.0	13.2
West Wallsend substation	0.0	0.0	0.3	0.7	1.4	2.4
Inner metropolitan upgrade	2.0	10.1	6.4	8.6	9.4	36.5
CBD upgrade	4.0	0.0	0.0	0.0	0.0	4.0
Growth sub total	**23.7**	**14.6**	**7.7**	**9.8**	**10.8**	**66.6**
Replacement driven expenditure						
Transmission substations	0.0	2.6	1.5	0.6	3.9	8.6
Green Square zone	11.3	5.9	0.6	2.0	0.4	20.2
Ourimbah replacement	0.0	0.5	2.5	7.0	6.1	16.1
Zone substations	0.0	2.2	0.5	0.0	0.6	3.3
Transmission mains	0.2	0.6	0.4	0.5	0.3	2.0
Feeder 908/909	0.4	2.0	23.7	10.0	0.0	36.1
Network control & communication	0.7	0.6	0.7	0.6	0.6	3.2
Replacement sub total	**12.6**	**14.4**	**29.9**	**20.7**	**11.9**	**89.5**
Non-system expenditure						
Transmission non-system	5.6	5.6	5.3	5.6	5.6	27.7
Total capex	**41.9**	**34.6**	**42.9**	**36.1**	**28.3**	**183.8**

Note: Numbers may not add due to rounding.

4.6 Implications of the ex-ante approach for EnergyAustralia

The ACCC has discussed this approach with EnergyAustralia and consider it is possible to review EnergyAustralia's future capex under the ex-ante approach. However to do this EnergyAustralia would need to make a further submission detailing how its forecast capex should be treated under an ex-ante approach.

EnergyAustralia's application is currently based on the principle that an ex-post assessment would be undertaken at the time of setting the revenue cap in 2009. The ACCC notes that after reviewing the initial application (and additional information provided) it would have required further information to conclude the prudency of EnergyAustralia's forecast capex.

After the review to date, the ACCC has provided a discussion of the further information required in the following section.

4.7 Information

4.7.1 Information in the application

Chapter 3 explains the information asymmetry that exists in relation to capex and sets out the importance of obtaining sufficient information from the TNSP. The same issues arise in relation to forecast capex. The ACCC can only make sound judgements on the efficiency of proposed capex if it has obtained sufficient information to demonstrate that the proposed investments are likely to satisfy the requirements of the code. This problem is discussed in chapter 5 of the DRP.

The ACCC considers the information provided in EnergyAustralia's revenue cap application is insufficient and did not demonstrate that:

- there was a need for each capex project
- EnergyAustralia had rigorously examined the options available
- the cost estimates used by EnergyAustralia were appropriate
- the overall capex program was appropriate.

4.7.2 Further information

In December 2003 the ACCC and its consultant, GHD, held a week of meetings with EnergyAustralia to discuss its application. The ACCC and GHD also requested that EnergyAustralia provide any or all further information that would assist the ACCC in determining the appropriateness of the future capex program.

Since that time, EnergyAustralia has provided more detailed information about the network deficiencies it is addressing. EnergyAustralia also provided several business case summaries, which are high level descriptions of the projects in its forecast capex program. These four page summaries generally included:

- a description of the project driver as either load at risk or loss of load
- a brief description of the project
- a brief note of assumptions used in the planning
- a brief note of prerequisite events or investments
- a timeline of deliverables
- a listing of risks associated with the project (not quantified)
- a basic breakdown of the cost estimate, in some cases a possible alternative to the preferred option.

The information received as a result of the meetings in December lacked the detail that could justify EnergyAustralia's plans. Hence at that stage neither GHD, nor the ACCC, could determine an appropriate level of capex for the upcoming regulatory period.

The ACCC conducted further interviews with EnergyAustralia in March 2004 to gain a better understanding of its future capex program. Consequently on 16 March 2004 EnergyAustralia submitted further documents regarding its forecast capex.

The information submitted at this time did not give the economic justification for the future projects. This information concentrated on load flow analysis and a detailed demonstration of the network deficiency driving the individual capex projects. Also, further details about the engineering scope were provided in some cases, however detailed cost estimates were not provided.

4.7.3 EnergyAustralia board approvals

In considering the interests of customers, the ACCC needs to be confident that EnergyAustralia is making prudent investment decisions. Hence the ACCC requested that EnergyAustralia provide board papers regarding approved capex decisions. EnergyAustralia declined to provide this information stating it considers that these documents contain commercially sensitive information.

The ACCC typically seeks board papers from TNSPs in order to satisfy itself that prudent investment decisions have been made following proper analysis and consideration of the relevant issues at the decision making level. Concerns about commercial sensitivity do not justify EnergyAustralia's refusal to provide this material to the ACCC. The procedures set out in clauses 6.2.5 and 6.2.6 of the code can be used to protect the confidentiality of information that is genuinely commercially sensitive while still enabling the ACCC to discharge its responsibilities.

4.7.4 Information required

EnergyAustralia states that the ACCC has not provided enough guidance as to what information it requires. The ACCC has provided the following guidance to EnergyAustralia in various discussions.

The ACCC must know the basis upon which EnergyAustralia's capex planning decisions are made. This will assist the ACCC to assess whether its capex plans are prudent.

EnergyAustralia must show why it has forecast $183.8 million capex over the 2004-2009 regulatory period. The information to support this will depend on the individual case and specific circumstances. However it should generally include, but may not be limited to:

- evidence of the driver for each project, which has already been provided in the majority of cases
- the code, regulatory and legislative requirements that may affect the possible solution
- the alternatives considered, including some from of detailed economic analysis of the alternatives
- detailed costs for the preferred option and the alternatives
- reasons why the preferred option would be or has been selected
- details of decisions that are committed
- details of community consultation
- details of the costs and benefits (quantified) of the preferred option and the alternatives
- details of the timing and risks of each option.

Chapter 5 of the code imposes network planning and development obligations that are designed to ensure that the most efficient investments are undertaken to address system limitations. Before the ACCC sets a revenue cap requiring customers to fund this investment, it must, at least, satisfy itself that the forecast capex program is consistent with these and any other relevant requirements of the code.

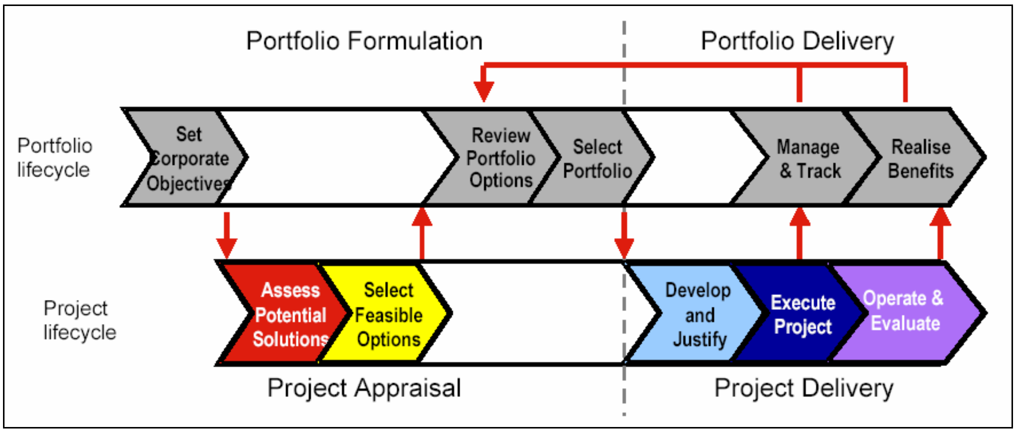
In addition the ACCC has reviewed EnergyAustralia's capital governance framework and replacement policies. This should also provide useful information to EnergyAustralia when considering what further information should be submitted.

4.8 EnergyAustralia's capital governance framework

EnergyAustralia has recognised that its past capital governance framework could be improved upon. Hence it has developed a new governance framework (see figure 4.1), which it outlined in its initial application.

This new process requires capital projects to undergo low level analysis designed to ensure that the best investment decision is made. However GHD could not find evidence that EnergyAustralia has formally adopted its new governance framework.

Figure 4.1 EnergyAustralia's new capital governance framework



Source: EnergyAustralia, *EnergyAustralia's submission to Australian Competition and Consumer Commission Transmission revenue determination 2004-2009*, 23 September 2003, page 14.

After EnergyAustralia submitted its application, it also submitted a document that included a description of its capex decision making process. This process is described as follows.

- Identify constraints through spatial load forecasts to determine priority areas.
- Undertake value management studies of the wider network area, including joint planning with TransGrid. This stage is aimed to develop strategies (both network and non-network) to resolve the identified issues. High level cost estimates are used at this stage with several options being selected for further development.
- If demand management is selected for further development, it is referred to EnergyAustralia's internal demand management team to test its feasibility.
- When deciding on a reliability augmentation the code requires EnergyAustralia to select the least cost option. Once this has been done a business case is approved by the 'Manager – Asset investment' and then further engineering design and costs estimates are developed.

However, the ACCC has not seen evidence that this process is implemented in practice. In reviewing the past capex the option that was normally selected and approved appears to be the option that was preferred in the value management study stage, which EnergyAustralia has described as 'high level planning'.

The documentation provided to the ACCC for future capex has been limited to the business case summaries.

While it is understandable that less detail would be provided for projects planned later in the regulatory period, the ACCC would expect more detail to be available, especially for projects due to commence in the next 2-3 years. EnergyAustralia has not been able to provide detailed economic analysis for capex projects due to start in the first half of the 2004-2009 regulatory period. This increases the ACCC's concerns about the risk of cost overruns in the future.

EnergyAustralia is required, under the code, to undertake an annual transmission planning review, which should also include some of this information.

4.8.1 Annual transmission planning review

Clause 5.6.2(d) of the code requires TNSPs to undertake an annual planning review over a minimum ten year planning period. The code also requires TNSPs to report on this planning review and that this must generally include distribution network service providers' load forecasts, proposed connection points and expected constraints over 1, 3 and 5 years.

In the case of an augmentation project the TNSP must include information about:

- the timing of the investment
- the reason the constraint (actual or forecast) would eventuate
- the proposed solution
- the estimated cost of the proposed solution
- whether the proposed solution would have a material inter-network impact
- reasonable alternatives considered.

The information to be included in the annual planning review must be reasonable and relative to the size and significance of the proposed expenditure. Further details are also required for new small network assets.

EnergyAustralia produces an annual report[25] to meet this code requirement, which may not be sufficient in meeting the full requirements of the code.

4.9 Capital refurbishment & replacement policy

EnergyAustralia has new capital refurbishment and replacement policies in place to assist it in identifying assets that need refurbishing or replacing.

This new policy aims to control the percentage of assets whose lives exceed the nominal life. EnergyAustralia notes that this is to ensure that the age profile of the system does not deteriorate to a stage where the burden of replacement is no longer sustainable.

The main objective of EnergyAustralia's high level replacement & refurbishment strategy is to target assets that are close to, or at the end of, their standard lives. EnergyAustralia's principles that guide its replacement and refurbishment capital program are:

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[25] EnergyAustralia, *Annual Electricity System Development Review*, May 2003.

- condition monitoring criteria shall be established, wherever possible, for specific classes of assets
- preferably no more than 40 per cent (in dollar terms) of a single category of assets shall exceed the standard regulatory asset life, unless asset condition overrides in specific cases
- preferably no more than 10 per cent of the total asset base (in dollar terms) shall exceed the regulatory standard asset life.

EnergyAustralia notes that generally all assets are replaced based on an assessment of their ability to continue their technical functions in a reliable, safe and environmentally sensitive manner. Experts on each asset category condition make the replacement decisions for the assets of their respective expertise.

For the general replacement category, 'Program control groups' meet on a regular basis to develop detailed replacement strategies. These groups also identify appropriate condition assessment criteria, decide the necessary scope of condition monitoring surveys, set priorities for specific implementation of surveys and develop the subsequent replacement implementation plans.

4.9.1 ACCC considerations

The ACCC understands that there are two checks that would normally occur as part of the decision to replace an asset. First, a basic check on asset ages is used to determine a pool of 'aged' assets. This pool can then be used as an indication of what assets should have their condition assessed as a matter of priority. These checks appear to be built into EnergyAustralia's replacement policy.

However, the ACCC has not seen evidence of how this policy has been practically applied. For example, EnergyAustralia have noted that the replacement of the Ourimbah substation is partly driven by the need to curtail the age of its assets. However there does not appear to be a condition assessment of the substation that would confirm the need for its replacement. The ACCC would expect that the size of this replacement and the medium level replacement strategy would reasonably require such an assessment.

4.10 Capital expenditure recognition/interest during construction

4.10.1 Summary of issue

In the 1999-2004 revenue cap decision, new capital investments were capitalised and included in the RAB the year after their commissioning date, with an allowance for interest during construction (IDC). In its application, EnergyAustralia acknowledges that it worked with the ACCC in ensuring that this approach maintained the value of investments at the time of the 1999-2004 revenue cap decision.

EnergyAustralia contends that this commissioning date approach to capex recognition is no longer appropriate for the following reasons.

- The calculation of IDC is complex when a project carries over regulatory periods.
- It is inconsistent with a probabilistic capex forecasting approach.
- It is administratively complex for large capital projects which have several stages, and hence, a number of commissioning dates.

Therefore, EnergyAustralia contends that the ACCC should adopt an approach whereby capex is recognised in the RAB on a cash spend basis. EnergyAustralia states that such an approach offers several advantages; including that:

- the regulator does not explicitly accept the specific set of projects forecast by the TNSP
- it provides TNSPs with greater flexibility to alter their capital programs to address changing circumstances
- it is administratively easier to manage and record.

EnergyAustralia submits that the ACCC should adopt an annual cash spend approach to the recognition of capex, with an allowance for financing costs associated with the expenditure during the year.

4.10.2 ACCC's considerations

The ACCC accepts EnergyAustralia's arguments and will include efficient forecast capex in the revenue allowance for the 2004-2009 revenue cap decision on an as incurred or cash spend basis. Such an approach is administratively superior and is consistent with the probabilistic capex forecast utilised in the ACCC's most recent revenue cap decisions.

4.11 Draft decision

The ACCC acknowledges that EnergyAustralia's initial application was not prepared with the objective of setting a fixed cap for capital expenditure, but rather to determine a path of prices and cash flows. The ACCC therefore considers that EnergyAustralia's request to resubmit its future capex application is reasonable.

One issue presented by the extension of time for the submission and assessment of EnergyAustralia's future capex application is that the code requires EnergyAustralia and TransGrid to publish transmission prices for the following financial year by 15 May 2004.

Therefore the ACCC has provided a provisional capex allowance that EnergyAustralia can use as a guide in setting and subsequently publishing transmission prices. The ACCC has used EnergyAustralia's proposed $183.8 million to set the maximum allowed revenue. This will enable EnergyAustralia to prepare its transmission prices for the 2004/05 financial year and any adjustments required will be made in the final revenue cap decision.

The ACCC will consider making its final revenue cap decision using the ex-ante approach. To do this, the ACCC anticipates that EnergyAustralia will submit a proposal on how its forecast capex should be treated under an ex-ante approach. This will require further consultation with interested parties and additional time to make a final decision. To do this the ACCC has proposed an indicative timetable in section 4.11.2.

In adopting this approach the ACCC has not formally considered issues relating to EnergyAustralia's forecast capex. For example GHD recommended capex savings of $1.419m per annum[26]. The ACCC will consider this and other issues relating to forecast capex in a supplementary draft decision as indicated by the timetable in the following section.

4.11.1 Submissions

In this draft decision, the ACCC has not explicitly addressed the issues raised in the submissions. It will address the relevant issues in the supplementary draft decision. The submissions from interested parties that have been received to date can be summarised as follows.

The EMRF criticised EnergyAustralia's initial application for $135 million capex over the regulatory period. It considers that this increase on past capex would have been unacceptable.

The customers' group also notes EnergyAustralia's capex proposal exceeds TransGrid's as a percentage of its RAB.

[26] GHD, *EnergyAustralia regulatory review, Capital expenditure and Asset base, Operational expenditure and service standards*, March 2004, page 50.

4.11.2 The remaining consultation process timetable

An indicative timetable for the future capex assessment follows:

Early May 2004	ACCC releases draft decision on EnergyAustralia's initial application and invites submissions. Interested parties have 14 days from the release of the draft decision to request a public forum.
Friday 2 July 2004	Close of submissions on draft decision.
End October 2004	Anticipated receipt of EnergyAustralia's additional capex application. ACCC invites interested party submissions on EnergyAustralia's additional application.
Mid December 2004	ACCC releases consultant's report on EnergyAustralia's application for public consultation.
End January 2005	Close of submissions on EnergyAustralia's application and consultant's report.
Mid February 2005	ACCC releases supplementary draft decision in relation to forecast capex and invites submissions. Interested parties have 14 days from the release of the supplementary draft decision to request a public forum.
Early March 2005	Public forum on supplementary draft decision (if requested).
End March 2005	Close of submissions on supplementary draft decision.
Mid April 2005	ACCC releases final decision.

5. Operating and maintenance expenditure

5.1 Introduction

In setting EnergyAustralia's MAR, the ACCC must assess EnergyAustralia's capacity to achieve realistic efficiency gains in its proposed opex. At the same time, because it represents a large proportion of the network's variable costs, opex is also an important source of savings and productive efficiencies over the short to medium term.

An important focus of the ACCC's assessment is analysing the drivers underpinning changes in opex reported by EnergyAustralia. In addition, the ACCC will consider whether or not EnergyAustralia has adopted an appropriate balance between opex and capex and its effects on service standards. Finally, efficient opex is a key source of the overall productivity gains that the ACCC will consider in determining the incentive outcomes for EnergyAustralia's revenue cap.

The remainder of this chapter sets out the requirements of the code and reviews the opex drivers identified in EnergyAustralia's application and by GHD in its review. The ACCC reviews past opex in order to determine an appropriate starting point for forecast opex (section 5.4) and then considers cost drivers which will impact on forecast opex requirement (section 5.5). Section 5.6 compares EnergyAustralia's performance to that of other TNSPs. The ACCC's draft decision is summarised in section 5.7.

5.2 Code requirements

The ACCC's task in assessing EnergyAustralia's opex is specified in the code. In particular, part B of chapter 6 of the code requires that:

- in setting the revenue cap the ACCC takes into account EnergyAustralia's revenue requirements, having regard to the potential for efficiency gains in expected *operating, maintenance* and capital *costs*, taking into account expected demand growth and service standards

- the regulatory regime must seek to achieve efficiency in the use of existing infrastructure, *efficient operating and maintenance practices*, and an efficient level of investment. [Italics added]

5.3 EnergyAustralia's application

EnergyAustralia put forward a proposal for opex that reflects changes in its transmission asset base, changes in the methodology for estimating opex requirements, the impact of asset age and a move from time based to reliability centred maintenance (RCM). Further EnergyAustralia notes that changes in the regulatory environment (occupational health and safety (OH&S) and environmental regulations), and increases in insurance and superannuation costs have all placed upward pressure on opex requirements.

EnergyAustralia has proposed total opex of $24.4 million in 2004/05 increasing in real terms to $27.7 million by 2008/09, as show in the Table 5.1. This proposed opex requirement has been developed taking into account the increased amount of transmission assets and using the revised allocation of opex by asset class (see section 5.4.1). EnergyAustralia's proposed opex for 2004/05 represents a step increase of around 13 per cent over its forecast opex for 2003/04, and a 39 per cent increase when compared to the opex approved by the ACCC for 2003/04.

Table 5.1 EnergyAustralia's proposed total opex ($m 2003/04)

	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Maintenance expenditure	13.28	14.51	15.74	16.89	18.20	78.63
Other	11.09	11.24	10.82	10.25	9.53	52.93
Total	**24.37**	**25.75**	**26.56**	**27.14**	**27.73**	**131.55**

Source: EnergyAustralia's application, Attachment G (allocation between maintenance and other varies throughout EnergyAustralia's application, but the total remains the same)

EnergyAustralia claims the ageing of its asset base and relatively low levels of replacement capex in the 1999-2004 regulatory period are both factors that contribute to increasing opex requirements in the 2004-2009 regulatory period.

EnergyAustralia also stresses the ongoing importance of the change to RCM, which has involved establishment costs, noting that savings from the change to RCM are not likely to be realised in the short term due to the increasing age of the transmission assets.

Further, EnergyAustralia notes that the change to RCM has facilitated a more reliable methodology for allocating opex between distribution and transmission assets. This new allocation framework uses asset category as a basis for allocation and EnergyAustralia states that it provides a far more accurate basis for identifying maintenance costs by asset class and allocating remaining shared costs between distribution and transmission assets.

5.3.1 Submissions on EnergyAustralia's application

In considering EnergyAustralia's proposed opex for the 2004-2009 regulatory period, the EMRF states that it is unable to readily obtain data on actual opex for the transmission network in relation to the 1999-2004 regulatory period. The EMRF expects the ACCC to require its consultants to review the efficiency of actual and forecast opex.

The EMRF further notes that partial productivity measures for the transmission network (such as opex per customer and opex per MWh) should be benchmarked against other comparable networks.

The customers' group expresses strong concerns about EnergyAustralia's proposed opex, suggesting that EnergyAustralia may be over estimating its actual requirement.

5.4 Opex 1999-2004 regulatory period

In order to judge whether or not EnergyAustralia's proposed opex requirement and hence operating and maintenance practices are efficient, as required by the code, the ACCC needs to be confident of the starting point for future expenditures. Hence GHD was engaged to review EnergyAustralia's proposed opex by analysing EnergyAustralia's opex in the 1999-2004 regulatory period, with a view to providing the ACCC with guidance about the reasonableness of both the opex starting point and path for the 2004-2009 regulatory period.

As with capex, the dual nature of EnergyAustralia's network business (distribution and transmission) and the availability of data has impacted on the accuracy of any analysis, and constrained GHD's ability to make recommendations to the ACCC.

When EnergyAustralia's 1999-2004 revenue cap decision was being determined by the ACCC, EnergyAustralia had a limited ability to provide an accurate estimate of the transmission component of its network operating costs. As a result, EnergyAustralia estimated these costs via a global allocation based on the proportion of the replacement cost of transmission assets relative to total network assets. The results of the global allocation framework are shown in the Table 5.2.

Table 5.2 Approved and actual opex for 1999-2004 ($m nominal)

	1999/00	2000/01	2001/02	2002/03	2003/04	Total
Opex approved in 1999-2004 decision	16.45	16.71	16.98	17.25	17.53	84.92
Actual opex	20.90	24.40	29.30	27.10	18.98[1]	120.68
Overspend	**4.45**	**7.69**	**12.32**	**9.85**	**1.45**	**35.76**

1. Forecast based on original definition of transmission assets and revised asset class allocation framework.

GHD was asked to judge whether EnergyAustralia's expenditures over and above the amount allowed in the 1999-2004 decision represented efficient opex, for the purpose of determining a reasonable starting point and projecting a suitable path for opex in the 2004-2009 regulatory period. To do this, GHD had to determine how much was actually spent by EnergyAustralia on opex for transmission assets. This amount cannot be determined exactly as EnergyAustralia does not keep expenditure records in sufficient detail. These data limitations led GHD to approach this task by considering total network opex (distribution and transmission) for EnergyAustralia, reviewing the cost drivers that impact on opex, and allocating resultant efficiencies to transmission. The allocation methodology and significant cost drivers are discussed below.

The purpose of examining the cost drivers is to determine what an efficient amount of opex for transmission would have been in each of the years in the 1999-2004 regulatory period and, in turn, to provide a starting point from which to assess the efficiency of EnergyAustralia's forecast opex for the 2004-2009 regulatory period.

5.4.1 Allocation methodology

For the purposes of determining how much EnergyAustralia spent on opex for transmission assets, three sets of data exist for the 1999-2004 regulatory period. The data reflects different allocation frameworks, and different definitions of transmission assets. It is important to bear in mind that despite the historical nature of these measures, all three are approximations and the "true transmission opex" cannot be determined for the reasons outlined above. The three sets of data are as follows.

- Original opex: based on the original definition of transmission assets agreed by the ACCC in 1998, and apportioned using a global allocation framework.
- Amended opex: based on the original definition of transmission assets agreed by the ACCC in 1998, and apportioned using an asset class allocation framework.
- New opex: based on the new definition of transmission assets agreed to by the ACCC in 2003 and apportioned using an asset class allocation framework.

EnergyAustralia has provided estimates of opex using each of these definitions, as shown in Table 5.3. In each case the estimate of actual expenditures is significantly greater than the approved opex allowed in the ACCC's 1999-2004 revenue cap decision. The average difference as a percentage using the original opex definition (global allocation framework) is 51 per cent, much higher than the 12 per cent average difference using the amended opex definition (asset class allocation framework).

Table 5.3 Approved and actual opex by definition ($m nominal)

	1999/00	2000/01	2001/02	2002/03	2003/04
Approved 1999 decision[1]	16.45	16.71	16.98	17.25	17.53
Original opex actual[1] (difference)	20.90 (4.45)	24.40 (7.69)	29.30 (12.32)	27.10 (9.85)	N/A
Amended opex actual[2] (difference)	17.54 (1.09)	19.23 (2.52)	19.10 (2.12)	19.30 (2.05)	18.98 (1.45)
New opex actual[3] (difference)	19.74 (3.29)	21.77 (5.06)	21.66 (4.68)	21.66 (4.41)	21.58 (4.05)

1. Based on original definition of transmission assets and global allocation framework.
2. Based on original definition of transmission assets and revised asset class allocation framework.
3. Based on new definition of transmission assets and revised asset class allocation framework.

GHD contends that the most appropriate definition of opex to use when reviewing past opex is the definition used at the time of the ACCC's 1999-2004 revenue cap decision. That is, the original definition of transmission assets and the global allocation framework. In making this choice GHD states that it enables them to compare like with like, as required under the terms of reference, and notes that the ACCC's 1999-2004 revenue cap decision may well have been different if a different allocation framework or definition of transmission assets was used.

The ACCC agrees with GHD and considers that the review of opex for the 1999-2004 regulatory period must be undertaken using the same definition of transmission assets and cost allocation methodology that was used at the time of the 1999-2004 revenue cap decision. If a different definition was used, the ACCC would be considering the efficiency of EnergyAustralia's opex by comparing forecast opex on one set of assets with actual opex on a different set of assets. This would inevitably lead to a less accurate outcome than that which would be achieved by comparing forecast and actual opex on the same class of assets.

5.4.2 Opex cost drivers

Superannuation costs

EnergyAustralia's total network opex for the 1999-2004 regulatory period includes superannuation costs of over $78 million in the years 2000-2003. GHD states that such expenditures should not be considered as opex but should be treated as extraordinary expenses. GHD recommends adjustments to EnergyAustralia's transmission opex as set out in Table 5.4.

Table 5.4 GHD's recommended superannuation opex adjustments ($m 2003/04)

	2000/01	2001/02	2002/03
Superannuation impact on transmission opex	1.81	4.37	1.91
Recommended variation	**+0.05**	**-2.50**	**-0.05**

Source: GHD, *EnergyAustralia Regulatory Review Report*, Table 17, p. 61.

GHD states that the recommended variation includes an adjustment for smoothing, which is intended to ensure that the data better reflects a suitable level of expenditure for EnergyAustralia going forward.

However, EnergyAustralia include a 'normal' superannuation item in the opex estimates as shown in their annual reports for the 1999-2003 period. The superannuation expenses identified above by GHD are abnormal expenses and it is not clear to the ACCC that a suitable 'smoothed' level of abnormal expenditure can or should be determined. Hence the ACCC does not accept that the smoothing step suggested by GHD is necessary, and will adjust EnergyAustralia's opex by the full amount of the abnormal superannuation expenditure allocated to transmission.[27] This adjustment is shown in Table 5.5.

[27] The ACCC notes that the amounts are taken from EnergyAustralia's annual reports and do not account for regulated/unregulated proportions. However, these values are the best available data at this time.

The ACCC also notes that EnergyAustralia's annual report shows a marked increase in superannuation expenditure (excluding abnormal items) over the 1999-2004 regulatory period, up from around $3 million in 1999/00 to $23 million in 2002/03.

EnergyAustralia has not addressed this matter in its application, or in any of the supplementary information provided to the ACCC. While increasing staff levels are assumed to have impacted on superannuation expenses, other factors must also have contributed to the sixfold increase. The ACCC will review this further before making its final decision on EnergyAustralia's revenue cap, but at this stage the ACCC has not identified or excluded an amount in the actual opex for the 1999-2004 regulatory period.

Olympics

EnergyAustralia's annual report provides information about its involvement as a sponsor of the Sydney 2000 Olympic Games and the additional costs involved in ensuring uninterrupted supply during that period. GHD argues that the sponsorship money and time spent should be viewed as a donation rather than opex. However, GHD could not accurately identify the amount inappropriately charged to maintenance, beyond noting a real increase of around $3 million in the years 1999/00 and 2000/01.

GHD suggests that opex for each of the relevant two years could be reduced by an amount in the range $0-$3 million (i.e. $0 to $6 million in total). The ACCC agrees with GHD and has decided to adjust opex by $3 million in total over the two years, which when allocated to transmission equates to $0.202 million in 1999/00 and $0.098 million in 2000/01. The ACCC has opted to make a $3 million adjustment, as this amount is in the middle of the range suggested by GHD.

Purchasing policies

EnergyAustralia has previously used a purchasing policy that sourced plant and equipment from the cheapest supplier. Such a policy has long term costs, in terms of increased ongoing costs for spare parts, increased costs of maintaining skills and training of staff for ongoing maintenance of a large variety of plant and equipment. EnergyAustralia claims that as the cost of the previous purchasing policy has become known, changes have been implemented to better standardise parts and equipment. This change in policy should introduce ongoing cost efficiencies and EnergyAustralia has included expected efficiencies in its proposed opex.

However, the past purchasing policies can in no way be considered efficient, and hence actual opex in the 1999-2004 regulatory period is subsequently greater than the level of efficient opex that EnergyAustralia required.

GHD states that it is unable to determine the costs of the purchasing policy, but estimates savings of around 1 per cent per annum should have been possible. GHD considers that these costs should be disallowed. The ACCC agrees that costs of inefficient work practices or policies should not be included in the determination of an efficient starting point for future opex. However, without further details the ACCC is not proposing to make any specific adjustment at this stage, but will consider the matter further prior to making its final revenue cap decision.

Insurance

Increasing insurance costs have impacted on all Australian businesses since 2001, reflecting increased risk premiums following the September 11 terrorist attacks in the United States of America. EnergyAustralia is no exception, showing a step increase in insurance costs from $0.8 million in 2000/01 to $6.6 million in 2001/02, which then reduced to around $3.2 million in 2002/03.

GHD, in its report:

> ...deem all years with the exception of 2001/02 as prudent, and would have expected a prudent organisation to have minimised the almost 9-fold increase in that year. A reasonable expenditure level in 2001/02, in line with the step increase that would have been experienced due to the September 11 attack would be equivalent to the 2002/03 expenditure.[28]

GHD recognises that increased insurance costs are expected but believe the size of the insurance expenditure in 2001/02 is too high, given the reduced expenditure in the following year. GHD has estimated that 2001/02 insurance costs should have been equivalent to 2002/03 costs ($3.19 million) and have recommended a reduction in allocated transmission opex of $0.34 million.

Further the ACCC notes that insurance expenses for other NSW electricity businesses did not show the same fluctuations, suggesting that EnergyAustralia's cost increases may have been driven by factors beyond the September 11 terrorist event.[29] However, EnergyAustralia's application has not offered any further explanation of the fluctuations in its insurance costs. The ACCC considers that electricity consumers should not be obliged to pay for inefficient expenditure decisions made by EnergyAustralia, and hence the ACCC has decided to implement GHD's recommendation that the insurance costs in 2001/02 are inefficient and will adjust the past opex accordingly.

OH&S and environmental legislation

EnergyAustralia's application details the impact of the changes to the regulatory environment on their opex. GHD notes that such changes impact on many organisations and in the case of environmental legislation, the data provided is deemed comparable with other organisations. GHD does not recommend any adjustment to these expenditures and the ACCC accepts GHD's recommendation.

Consolidation of EnergyAustralia

EnergyAustralia has made efficiency savings of 3.5 per cent through corporate restructuring, which are incorporated in its opex claim. The ACCC considers continued efficiency savings may be possible as EnergyAustralia continues with the process of integration of systems and rationalisation of organisation structures that have arisen through the merging of different organisations to form EnergyAustralia. However,

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[28] GHD, *EnergyAustralia Regulatory Review Report*, p. 62.

[29] TransGrid annual reports 2001, 2002 & 2003 and Integral Energy annual reports 2002 & 2003.

rather than make a specific adjustment, efficiency savings arising from organisation consolidation are incorporated in the general opex efficiency adjustment, as discussed below.

Full retail contestability

GHD notes that the costs associated with full retail contestability (FRC) were incorporated into the ‘other’ category, and according to SKM were to be reduced to zero by 2002/03. However, GHD did not find evidence of this and could not determine whether the costs were efficient.

However, FRC should not be relevant to EnergyAustralia’s transmission business - it should only impact on EnergyAustralia’s retail business. Hence the ACCC considers that all identified FRC costs should be excluded from the estimates of transmission opex. To date the ACCC has not been able to identify these costs and will seek further information from EnergyAustralia prior to making the final decision.

Staffing and productivity

EnergyAustralia notes that the high degree of competition for skills and trained staff in the NSW electricity sector has resulted in high staffing costs. To combat this, EnergyAustralia has introduced greater trainee recruitment, which has led to higher recruitment and training costs, and slightly greater employee numbers. GHD contends that these costs should be offset by lower salaries, and hence have no overall impact on opex costs.

GHD also notes that expected productivity improvements have not been identified by EnergyAustralia and that future productivity improvements, for example from the introduction of RCM, will not occur in the 2004-2009 regulatory period. GHD states that there should have been productivity improvements of at least 1 per cent per annum and recommends adjusting the opex estimates accordingly.

The ACCC agrees with GHD’s recommendation that EnergyAustralia should have been able to achieve some productivity improvements during the 1999-2004 regulatory period. However, rather than apply a specific adjustment to EnergyAustralia’s opex the ACCC is incorporating this potential efficiency gain into general opex efficiency, as discussed below.

Maintenance regime

EnergyAustralia have stressed the importance of the change in its maintenance regime to RCM, and its likely impact in future regulatory periods. GHD notes that such expenditure should be considered efficient, given the expected long term benefits from comprehensive implementation of asset lifecycle costing and asset management practices.

The ACCC agrees that the change to RCM should represent a dramatic improvement over previous asset management practices but notes the direct costs of this change have not been identified.

General opex efficiency

GHD believes that an efficient business should have readily been able to achieve opex efficiency gains over the 1999-2004 regulatory period. However, GHD did not find any evidence that such gains were pursued or achieved by EnergyAustralia. GHD recommends that a reduction be applied to EnergyAustralia's opex, increasing by 0.5 per cent each year from 0.5 per cent in 1999/00 to 2.5 per cent in 2003/04. The ACCC agrees with GHD's assessment.

Further, the ACCC notes that there are several areas in opex where GHD considered efficiencies could have been expected, or have not been fully justified by EnergyAustralia as efficient expenditure. These are described above. Some of these areas have been dealt with and specific adjustments were made, but in other cases no specific adjustment has been made by the ACCC. The case for the efficiency gain recommended by GHD is supported by the fact that there are some additional areas where efficiency gains could have been expected, but for which no specific adjustment has been made to the amount that should have been spent by EnergyAustralia in the 1999-2004 regulatory period.

The ACCC has therefore accepted GHD's suggestion of imposing an overall efficiency saving to EnergyAustralia's opex in the 1999-2004 regulatory period. If the general efficiency gains recommended by GHD and adopted by the ACCC were to be excluded, a more rigorous assessment by the ACCC of the identified cost drivers would be justified.

5.4.3 Efficient opex 1999-2004 regulatory period

The review of opex in the 1999-2004 regulatory period is a necessary step in determining the reasonableness of the starting point and path of projected opex in the 2004-2009 regulatory period.

As discussed in section 5.4.2, the ACCC considers a number of adjustments need to be made to EnergyAustralia's proposed opex starting point for the 2004-2009 regulatory period. These adjustments reflect the ACCC's findings on what an efficient amount of opex would have been for the 1999-2004 regulatory period. These are summarised in the Table 5.5.

Table 5.5 Summary of proposed opex adjustments ($m 2003/04)

Cost driver	Year	GHD recommendation	ACCC adjustment
Superannuation –abnormal	2000/01	+$0.05	-$1.81
	2001/02	-$2.50	-$4.37
	2002/03	-$0.05	-$1.91
Olympics	1999/00	range provided	-$0.20
	2000/01	range provided	-$0.10
Insurance	2001/02	-$0.34	-$0.34
Productivity and general opex efficiency	1999/00	-0.5%, -$0.12	-$0.12
	2000/01	-1.0%, -$0.27	-$0.27
	2001/02	-1.5%, -$0.47	-$0.47
	2002/03	-2.0%, -$0.56	-$0.56
	2003/04	-2.5%, -$0.75	-$0.75

The impact of the above adjustments on EnergyAustralia's opex for the 1999-2004 regulatory period is summarised in Table 5.6.

Table 5.6 EnergyAustralia's opex adjusted for efficiencies ($m 2003/04)

	1999/00	2000/01	2001/02	2002/03	2003/04
EnergyAustralia's actual opex	24.35	26.70	31.14	27.91	28.78[1]
Adjustments:					
Superannuation		1.81	4.37	1.91	1.97[1]
Olympics	0.20	0.10			
Insurance			0.34		
General efficiency	0.12	0.27	0.47	0.56	0.75
ACCC adjusted opex	**24.03**	**24.52**	**25.96**	**25.44**	**26.06**

1. These forecasts were not provided and hence the ACCC used a 2002/03 estimate including an assumed CPI adjustment of 3.1 per cent.

5.5 Opex 2004-2009 regulatory period

EnergyAustralia's application incorporates an increase in opex for the 2004-2009 regulatory period, estimating its starting point at $24.37 million, growing to $27.73 million by 2008/09. This is an increase in real terms of 14 per cent over the period. However EnergyAustralia's estimates also include an amended starting point, taking into account new asset definitions and a new allocation framework. EnergyAustralia's proposed starting point represents an increase of 13 per cent when compared to the forecast opex for 2003/04.

5.5.1 Opex allocation framework

GHD states that the new allocation framework provides a better representation of actual transmission costs, noting that in-depth analysis of transmission opex would require either a full assessment of whole of business opex or a splitting of the transmission and distribution accounts. GHD also notes the new asset definition has been accepted by the ACCC and as such needs to be incorporated into the future estimates of opex.

GHD has provided estimates of the impact of the change in asset definition and allocation methodology on the original estimates of opex by EnergyAustralia. The change, expressed as a proportion of the original estimate is then used to amend the adjusted opex for the 1999-2004 regulatory period.

The ACCC has followed this methodology to estimate the new starting point for EnergyAustralia's opex for the 2004-2009 regulatory period. Table 5.7 sets out the calculation for determining this proportion to apply to the ACCC adjusted opex (in Table 5.6).

Table 5.7 EnergyAustralia's opex amended for new asset definition and allocation framework ($m 2003/04)

	1999/00	2000/01	2001/02	2002/03	2003/04
EnergyAustralia's actual opex[2]	24.35	26.70	31.14	27.91	28.78[1]
EnergyAustralia's new opex[3]	23.00	23.82	23.02	22.30	21.58
EnergyAustralia's new opex ÷ EnergyAustralia's actual opex (%)	94.46	89.21	73.92	79.90	74.98[1]
ACCC adjusted opex[2]	24.03	24.52	25.96	25.44	26.06[1]
EnergyAustralia's new to actual opex proportion (%)	94.46	89.21	73.92	79.90	74.98[1]
ACCC new opex[3]	**22.70**	**21.87**	**19.19**	**20.33**	**19.54**

1. These forecasts were not provided and hence used a 2002/03 estimate including an assumed CPI adjustment of 3.1 per cent.
2. Based on original definition of transmission assets and global allocation framework.
3. Based on new definition of transmission assets and revised asset class allocation framework.

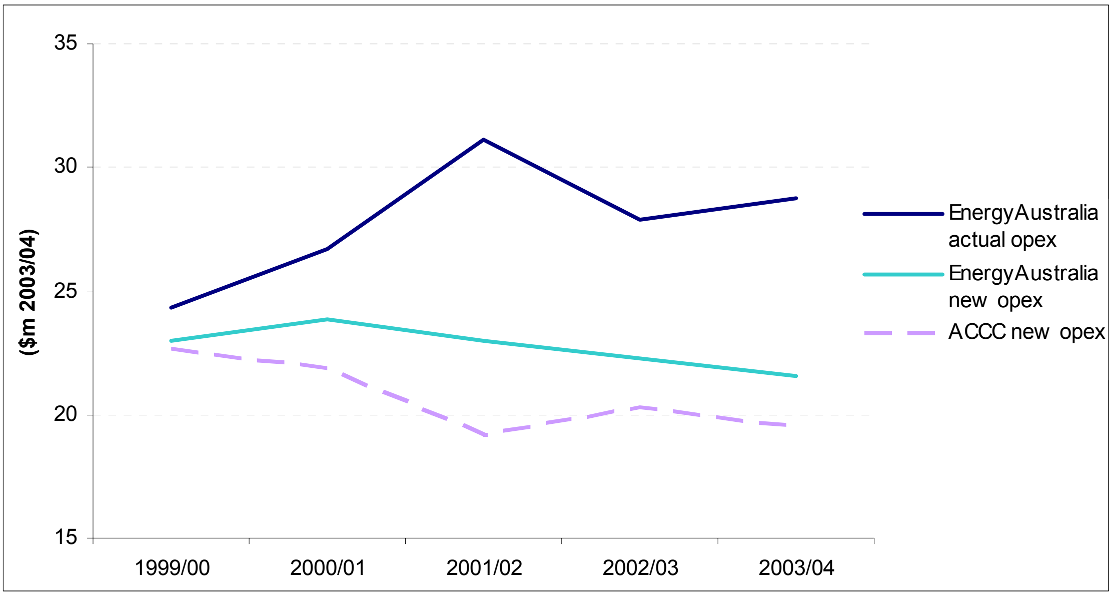
The ACCC new opex set out in Table 5.7 reflects the ACCC's view of an efficient opex spend by EnergyAustralia for the 1999-2004 regulatory period, based on the new asset definition and allocation framework.

As mentioned above, the purpose of assessing the past opex spend by EnergyAustralia is to provide the ACCC with guidance about the reasonableness of both the opex starting point and path for the 2004-2009 regulatory period. This is particularly important given the change to a new opex allocation framework and additional transmission assets to be included in EnergyAustralia's RAB.

The ACCC's calculation of the new 2003/04 opex, after adjustments for ACCC identified efficiencies, new transmission asset definition and new allocation framework implies a shift in EnergyAustralia's starting point of $2.04 million down from $21.58 million to $19.54 million in the year 2003/04. This reflects the ACCC's assessment of the efficient opex for transmission assets for this year if the new asset definition and allocation framework is used.

Figure 5.1 provides an indication of the wide variation of EnergyAustralia's reported opex depending on the allocation framework used and the inclusion of the new definition of transmission assets. A plot of the ACCC's assessment of EnergyAustralia's opex, after adjustments for ACCC identified efficiencies, new transmission assets definition and new allocation framework is also included in figure 5.1.

Figure 5.1 Comparison of opex, 1999-2004 regulatory period



5.5.2 Opex cost drivers

EnergyAustralia's application shows three core categories of opex; maintenance, communications and control, and other. GHD states that due to data limitations, (in particular the dual nature of EnergyAustralia's business and lack of specifically identified transmission costs) its review of proposed opex for the 2004-2009 regulatory period utilised an analysis of total network opex and its cost drivers, rather than a detailed expenditure review.

Table 5.8 EnergyAustralia's proposed opex allowance ($m 2003/04)

	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Maintenance	13.28	14.51	15.74	16.89	18.20	78.63
Communication and control	4.15	4.11	4.06	4.02	3.99	20.33
Other	6.94	7.13	6.75	6.23	5.54	32.59
Total opex	**24.37**	**25.75**	**26.56**	**27.14**	**27.73**	**131.55**

Source: EnergyAustralia's application, Attachment G

The key opex driver is the change in maintenance practices to RCM. The impact of this and other opex drivers is discussed below.

RCM

Maintenance is the largest component of EnergyAustralia's proposed opex, and it shows a real increase of over 37 per cent during the regulatory period. EnergyAustralia states that this increase is driven by the move to RCM from time based maintenance. This shift in maintenance practices has highlighted a large backlog of necessary maintenance, and hence EnergyAustralia claims the increased opex in the short term will drive substantial long term opex efficiencies.

GHD supports EnergyAustralia's change to RCM and does not recommend any adjustment to proposed opex in respect of this driver. The ACCC accepts GHD's recommendation.

Information Technology

EnergyAustralia has forecast large information technology (IT) expenditure aimed at risk management and compliance, rather than achieving efficiency gains. GHD states that EnergyAustralia should include a focus on potential efficiencies in its IT development, with expected efficiencies coming from ongoing consolidation of existing systems. GHD suggests that a reasonable level of saving would be within the range of 1-5 per cent per annum, given a one year lag.

The ACCC accepts GHD's recommendation and considers that EnergyAustralia should be striving for efficiency gains in the 2004-2009 regulatory period, and should be explicitly targeting areas such as IT opex, where savings can be made. Hence the ACCC will adjust EnergyAustralia's opex by 3 per cent in each year of the 2004-2009 regulatory period from 2005/06, as an efficiency driver in this area. The ACCC has selected 3 per cent as the mid point of the potential efficiency gains identified by GHD.

Insurance

EnergyAustralia's application highlights the impact of global events on insurance costs, and GHD agrees that insurance costs will be largely driven by factors outside EnergyAustralia's control. In the current global environment it is difficult to judge whether EnergyAustralia's proposed insurance costs are an over-estimate or under-estimate. The ACCC has decided not to make any adjustment to EnergyAustralia's proposed insurance expenditure.

Self insurance

Energy Australia is claiming an allowance for non-insured risks of $0.44 million per annum for identified events based on an actuarial assessment by Trowbridge Deloitte. The major non-insured risks identified are property related risks ($414,000), currently insured risks ($20,000), credit risks ($8,000) and other risks (n/a).

In general, the ACCC is required to apply incentive based regulation under the code. After careful examination of the merits of self insurance on efficiency grounds, the ACCC has determined that the following matters must be established prior to considering a self insurance application.

- Confirmation of the board resolution to self insure.
- A report from an appropriately qualified insurance consultant that verifies the calculation of risks and corresponding insurance premiums.
- Relevant self insurance details that unequivocally set out the categories of risk the company has resolved to assume self insurance for. This would need to clearly establish what the insured events and exclusions are so as to avoid any future debate as to whether or not an event was a self insured one and form the basis for actuarial assessment noted above.
- A regulated entity's resolution to self insure would also be expected to explicitly acknowledge the assumed risks of self insuring (i.e. in the event of future expenditure required as a result of an insurance event such costs would not be recoverable under the regulatory framework as the relevant premiums would have already been compensated for within the operating and maintenance element of the MAR and funded by users, for example, if a 1 in a 100 year event occurs in year 1 then the business will need to have the financial ability to restore assets out of its own resources).

Board resolution and corporate governance requirements are fundamental issues. Risk management strategy of an entity and approaches to events that could affect the overall risk profile of the entity are matters for board consideration. This is important because it may require parent entity/shareholder support to self-insure and/or affect debt covenant requirements of lenders. However, where a TNSP's decision to self insure is funded through its opex allowance, the decision must be transparent and clearly defined so as to ensure that it is not subsequently funded a second time, either through insurance costs or costs arising if the event should occur.

The ACCC will consider EnergyAustralia's claim for self insurance allowance as per the above guidelines. Final approval will depend on all elements being satisfied, in particular the provision of a board resolution regarding self insurance. This approach is consistent with the ACCC's SPI PowerNet decision[30] and the draft TransGrid revenue cap decision.

The ACCC considers that the allowance of $20,000 per annum for current insured risks held by EnergyAustralia should not be included in the proposed opex cash flows. This expenditure should be included in the pass-through mechanism as an Insurance Event, consistent with the approach adopted in the SPI PowerNet revenue cap decision.

With regard to the claim for non-insured risks identified in the Trowbridge Deloitte report ($0.42 million), the ACCC proposes to accept this claim on a provisional basis, but will only allow it upon receipt of a board resolution to self insure from EnergyAustralia in accordance with the ACCC guidelines on this matter. Such a resolution has not yet been received.

Corporate and contractor costs

Expenditure savings of 3.5 per cent have been achieved in this area due to a recent restructuring at EnergyAustralia. GHD expects that further opportunities with regard to organisational consolidation would exist and estimate savings of between 0.5-1.0 per cent per annum post implementation. The ACCC notes that if EnergyAustralia is able to further consolidate its organisational structure and achieve savings, then as an incentive for EnergyAustralia to strive for additional efficiencies, these savings should be allowed to remain with EnergyAustralia. Therefore, no further adjustment is proposed by the ACCC.

Enerserve and corporate procurement

EnergyAustralia finalised a detailed review of its corporate procurement strategies in 2002. The review identified many cost saving opportunities for EnergyAustralia. A particular opportunity exists within the labour resources associated with the Enerserve contract. GHD states that the associated savings are likely to be minimal and would lie within 0.5-1.0 per cent per annum. The ACCC does not propose to make any adjustment in this area.

Customer service levels

A large increase in customer service costs is forecast by EnergyAustralia but GHD was not able to determine whether this increase was incorporated into EnergyAustralia's proposed opex.

The ACCC considers that most of EnergyAustralia's customer service costs should be excluded from the regulatory activity, as customer service operations should form part of EnergyAustralia's retail activity. The information provided needs further clarification for the ACCC to be confident that these expenditures should be included in the transmission opex proposals. The ACCC has not made an adjustment to forecast opex for this draft decision but will undertake further review of this matter prior to its final revenue cap decision being made.

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[30] ACCC, *Victorian Transmission Network Revenue Caps -2003-2008 - Decision*, 11 December 2002.

Capitalisation policy

GHD notes that a new capitalisation policy has resulted in $2.2 million of expenditure relating to new installation inspections being capitalised. However, GHD could not identify this expenditure in EnergyAustralia's proposed opex nor ascertain how it was allocated to transmission.

The ACCC has not made an adjustment to forecast opex for this draft decision but will seek further information from EnergyAustralia on this matter prior to its final revenue cap decision being made.

Environmental legislation

Changes in environmental legislation have also impacted on EnergyAustralia's proposed opex. EnergyAustralia claims that an extra $6 million per annum in real terms is required for transmission opex in the 2004-2009 regulatory period. GHD states that EnergyAustralia's claim represents an appropriate allowance, and the ACCC accepts GHD's recommendation.

Confidential project

GHD identified a project that EnergyAustralia regards as confidential and as such the project was not discussed in detail but the implications of that project are referred to in GHD's report. Resource issues were identified as a constraint to the implementation of this project. As such, an increase of $0.074 million applied to transmission opex in 2004/05 is provided in support of project implementation. GHD has extrapolated the identified savings from the project and applied them to transmission opex, resulting in a recommended annual opex reduction of $1.419 million per annum, starting in 2005/06.

The ACCC has reviewed EnergyAustralia's confidential project and accepts GHD's recommendation.

Debt raising costs

As outlined in chapter 6, the ACCC will allow EnergyAustralia debt raising costs over the regulatory period. Consistent with the Transend[31] revenue cap decision, this cost is treated as an operating expense and is calculated by applying benchmark costs and gearing ratio to the asset base. Debt raising costs averaging about $0.41 million per annum are allowed over the 2004-2009 regulatory period.

5.5.3 Efficient opex 2004-2009 regulatory period

In order to derive the ACCC's proposed allowance for opex in the 2004-2009 regulatory period, EnergyAustralia's proposed opex is adjusted to reflect the new starting point, and then the impact of the efficiency drivers identified above are taken into account.

For the purposes of calculating an efficient starting point opex for 2004/05, the ACCC considers that EnergyAustralia's opex in the 1999-2004 regulatory period included

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[31] ACCC, *Tasmanian Transmission Network Revenue Cap 2004-2008/09*, 10 December 2003.

inefficiencies of around $2 million per annum. The ACCC also considers that different cost drivers will impact on EnergyAustralia's opex requirement in the 2004-2009 regulatory period and has identified further inefficiencies, for which adjustments are required. These adjustments and the ACCC's proposed opex allowance are set out in Table 5.9 and illustrated in figure 5.2.

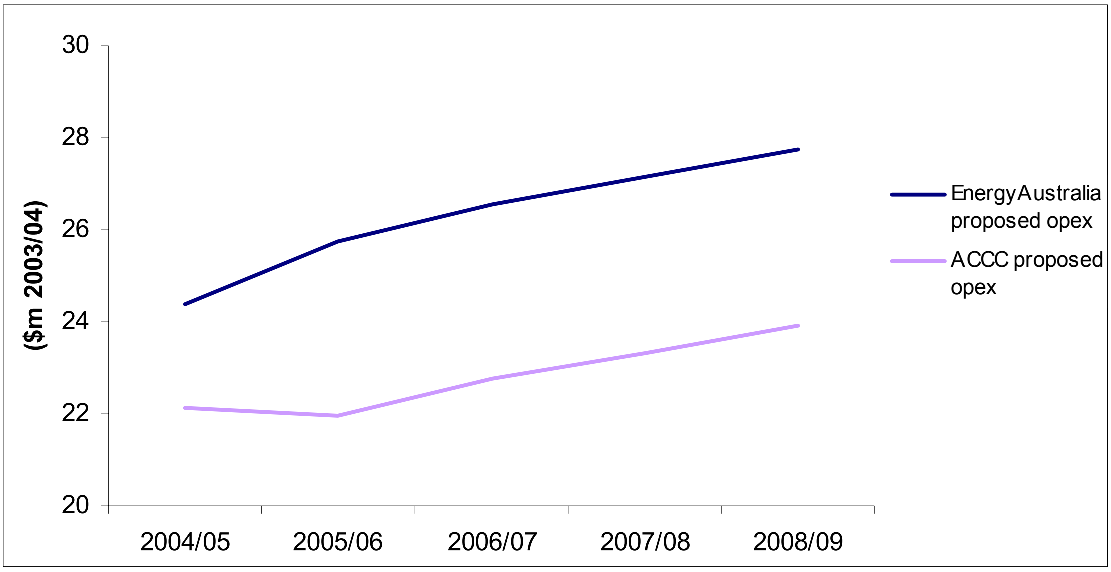
The ACCC notes that in other revenue cap decisions (Transend final decision and draft TransGrid revenue cap decision), it has imposed a general efficiency factor to forecast opex allowances. In assessing EnergyAustralia's forecast opex, the ACCC has identified specific cost drivers where scope for efficiency gains can be achieved. Therefore, for this draft decision the ACCC considers that applying a further general efficiency factor to EnergyAustralia's opex is not required.

Table 5.9 EnergyAustralia's opex ($m 2003/04)

	2004/05	2005/06	2006/07	2007/08	2008/09	Total
EnergyAustralia's proposal[1]	24.37	25.75	26.56	27.14	27.73	131.55
less: ACCC starting point variation ($2.04)	22.33	23.71	24.52	25.10	25.69	121.35
less: cost driver variation						
Confidential project	0.07	(1.42)	(1.42)	(1.42)	(1.42)	(5.61)
IT	(0.67)	(0.71)	(0.74)	(0.75)	(0.77)	(3.64)
Self insurance	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.10)
add debt raising cost	0.40	0.41	0.41	0.42	0.43	2.07
ACCC proposed opex	**22.11**	**21.97**	**22.75**	**23.33**	**23.91**	**114.07**

1. EnergyAustralia's opex forecasts do not include debt raising costs as they were included in its WACC calculations.

Figure 5.2 Opex 2004-2009 regulatory period ($m 2003/04)



5.6 Benchmarking

The ACCC is aware that several factors limit the usefulness of comparing opex of transmission companies. These include varying load profiles, load densities, asset age profiles, network designs, local regulatory requirements, topography, climate and accounting practices.

The ACCC understands that comparisons based on a single benchmark indicator are not very meaningful. Nonetheless, different indicators used in combination can help to assess whether a TNSP's opex is reasonable. Hence, the ACCC undertook its own benchmarking using several different ratios to make a general assessment of its proposed opex forecast for EnergyAustralia. Items such as financing costs and grid support were not included as they may obscure trends.

The ACCC notes that EnergyAustralia does not operate primarily as a TNSP, therefore some ratios must be viewed carefully when making comparisons. Notwithstanding this, EnergyAustralia operates a large network and accordingly on a whole of business approach, economies of scale in opex should be expected. The ACCC benchmarked EnergyAustralia against Transend, ElectraNet, Powerlink, SPI PowerNet/VenCorp and TransGrid. The results of the ACCC's analysis are shown in Table 5.10.

Table 5.10 Ratio analysis of EnergyAustralia compared to other TNSPs

		2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Opex/line length	ACCC Draft				23.73	23.56	24.42	25.04	25.66
(circuit $'000/km)	EnergyAust.	25.46	24.20	23.58	26.63	28.14	29.03	29.66	30.30
	Transend	5.78	6.51	7.30	8.00	8.58	7.98	7.79	7.76
	ElectraNet	6.42	6.99	7.60	7.57	7.64	7.75	7.79	
	Powerlink	4.88	5.28	5.46	5.63	5.32	5.98		
	SPI/Vencorp	8.01	9.19	11.60	11.60	11.66	11.65	11.66	
	TransGrid	8.43	8.57	8.70	9.30	9.24	9.19	9.13	8.95
Opex per	ACCC Draft				804	799	827	849	870
Substation ($'000)	EnergyAust.	863	820	799	903	954	984	1005	1027
	Transend	448	505	566	620	665	619	604	602
	ElectraNet	526	574	623	621	627	636	639	
	Powerlink	607	657	679	700	661	744		
	SPI/Vencorp	1193	1368	1727	1727	1736	1734	1736	
	TransGrid	1291	1312	1333	1424	1415	1407	1398	1371
Opex/asset base	ACCC Draft				3.45	3.25	3.24	3.16	3.13
(%)	EnergyAust.	4.37	4.20	4.06	3.88	3.89	3.85	3.75	3.69
	Transend	3.72	3.91	4.09	4.07	4.12	3.50	3.34	3.26
	ElectraNet	4.56	4.76	4.82	4.57	4.31	4.09	3.97	
	Powerlink	2.34	2.40	2.36	2.29	2.06	2.30		
	SPI/Vencorp	2.92	3.24	3.99	3.92	3.90	3.82	3.75	
	TransGrid	4.63	4.60	4.10	3.88	3.70	3.44	3.26	3.07
Opex/MW peak	ACCC Draft				10.16	10.09	10.45	10.72	10.99
($'000/MW)	EnergyAust.	10.90	10.36	10.10	11.40	12.05	12.43	12.70	12.98
	Transend	12.37	13.94	15.62	17.12	18.36	17.08	16.66	16.61
	ElectraNet	12.56	13.68	14.87	14.83	14.96	15.16	15.25	
	Powerlink	7.89	8.53	8.82	9.10	8.59	9.66		
	SPI/Vencorp	6.40	7.34	9.26	9.26	9.31	9.30	9.31	
	TransGrid	8.48	8.62	8.75	9.36	9.29	9.24	9.18	9.01
Opex/GWh	ACCC Draft				1.32	1.31	1.36	1.39	1.43
($'000/GWh)	EnergyAust.	1.42	1.35	1.31	1.48	1.56	1.61	1.65	1.68
	Transend	1.96	2.21	2.47	2.71	2.90	2.70	2.64	2.63
	ElectraNet	3.00	3.27	3.56	3.54	3.58	3.63	3.65	
	Powerlink	1.30	1.40	1.45	1.49	1.41	1.59		
	SPI/Vencorp	1.02	1.16	1.47	1.47	1.48	1.48	1.48	
	TransGrid	1.46	1.48	1.51	1.61	1.60	1.59	1.58	1.55

Note: Refurbishments, financing and grid support have been excluded from EnergyAustralia's, TransGrid's, Transend's, ElectraNet's and Powerlink's opex figures.

Source: EnergyAustralia opex figures from application and Attachment G ($real) and ACCC draft opex figures follow methodology employed in *GHD EnergyAustralia Regulatory Review* ($real).

Transend opex figures from 10 December 2003 *Tasmanian Transmission Network Revenue Cap 2004-2008/09* ($real).

ElectraNet opex figures from 11 December 2002 *South Australian Transmission Network Revenue Cap 2003-2007/08* ($real).

Powerlink opex figures from financial modelling ($real) used to develop final decision (*Queensland Transmission Network Revenue Cap 2002-2006/07)*.

SPI/VENCorp opex figures from 11 December 2002 *Victorian Transmission Network Revenue Caps 2003-2008* ($real).

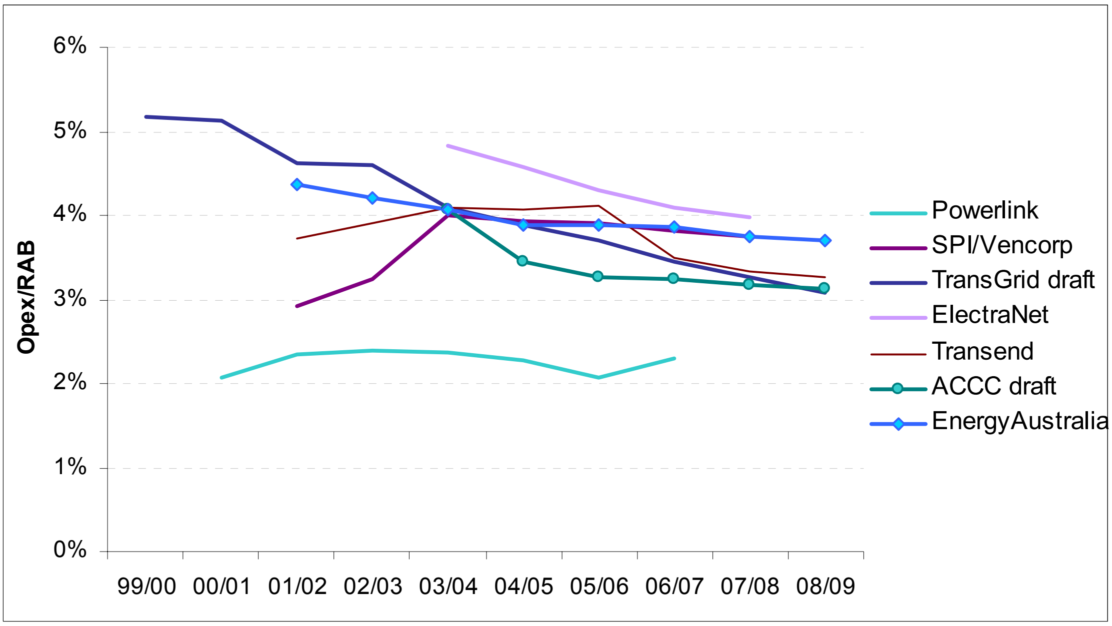
TransGrid opex figures from 25 January 2000 *NSW and ACT Transmission Network Revenue Caps 1999/00-2003/04* decision ($nominal) and ACCC draft decision *NSW and ACT Transmission Network Revenue Caps 2004/05-2008/09* ($real).

Figures 5.3 to 5.7 compare the level of opex proposed by the ACCC with that of other TNSPs for the following ratios: opex per asset base; opex per line length (circuit kilometres); opex per substation; opex per gigawatt hour (GWh); and opex per MW.

The ACCC considers that opex as a proportion of asset base, while having some limitations, is a more useful measure than the other ratios.

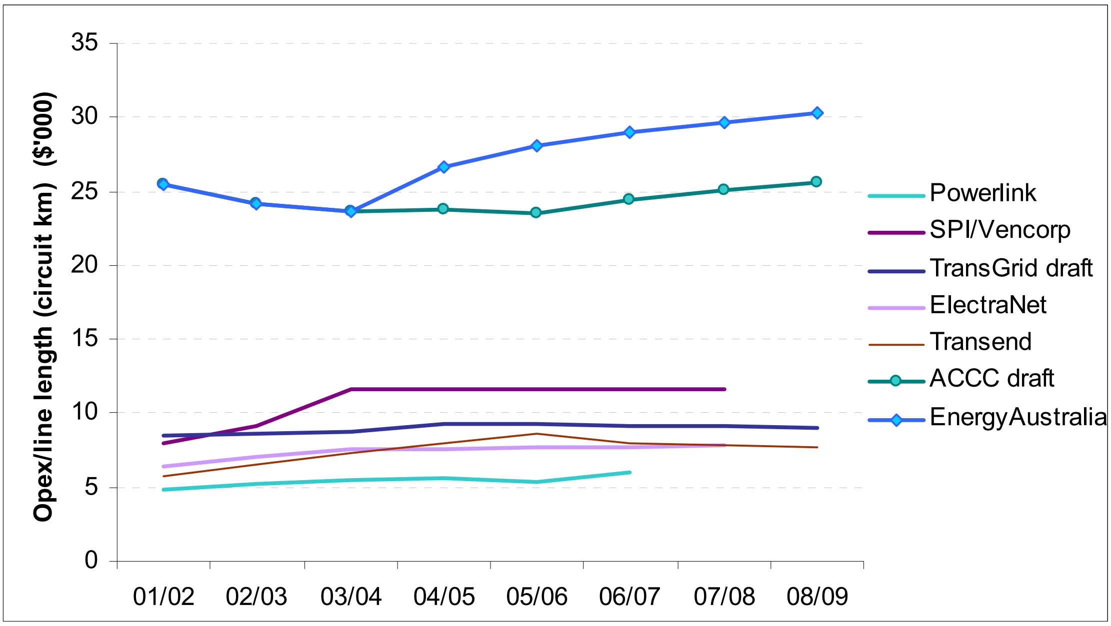
Figure 5.3 shows that the ACCC proposed opex as a percentage of EnergyAustralia's asset base over the regulatory period is reasonable compared with other TNSPs. The ACCC notes that the inclusion of additional assets into EnergyAustralia's transmission asset base has resulted in a significantly higher asset base compared to the 1999-2004 regulatory period. The increased RAB results in an improved ratio.

Figure 5.3 Comparison of TNSP's opex per asset base



In previous revenue cap decisions, the ACCC also considered that opex per unit of circuit length was a useful measure. Figure 5.4 shows that EnergyAustralia's opex is high compared to other TNSPs. However the ACCC is mindful that the opex per circuit length chart may show EnergyAustralia in a worse light than it actually is. For example, EnergyAustralia's network (which is largely distribution) has a compact transmission system based within the CBD region and thus its circuit line length is low.

Figure 5.4 Comparison of TNSPs opex per line length



Figures 5.5 to 5.7 show that EnergyAustralia's opex (as proposed by the ACCC) is about average compared to other TNSPs. The relative position is also quite stable from previous years to the 2004-2009 regulatory period. However, if EnergyAustralia's opex claim is used for comparisons, it shows that EnergyAustralia's relative position is trending upwards (with a step increase in 2004/2005).

Figure 5.5 Comparison of TNSPs opex per substation

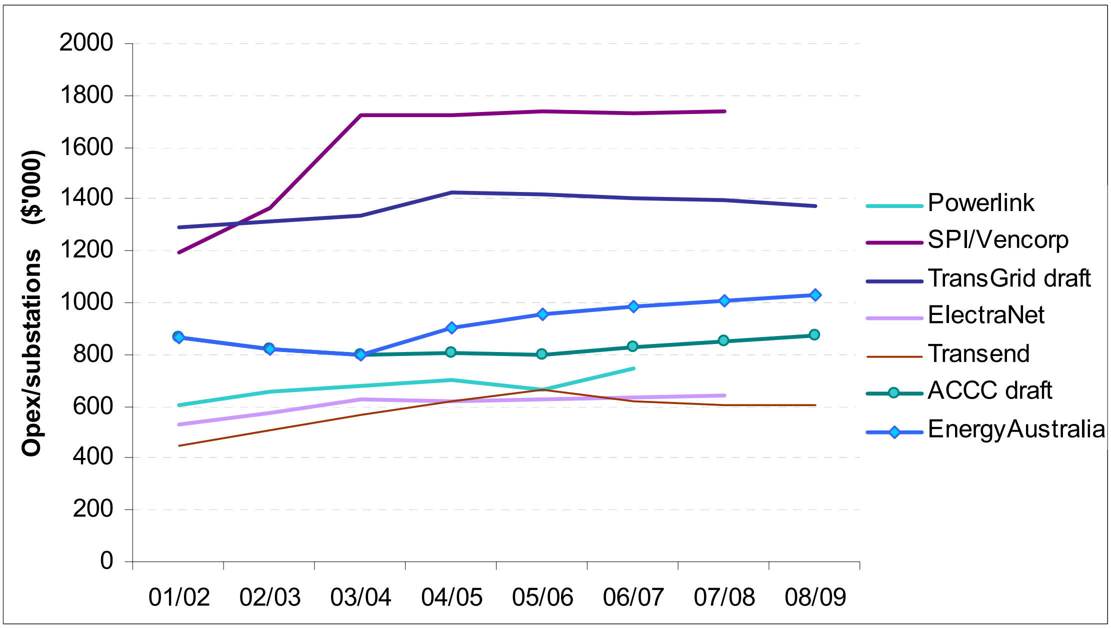


Figure 5.6 Comparison of TNSP's opex per GWh

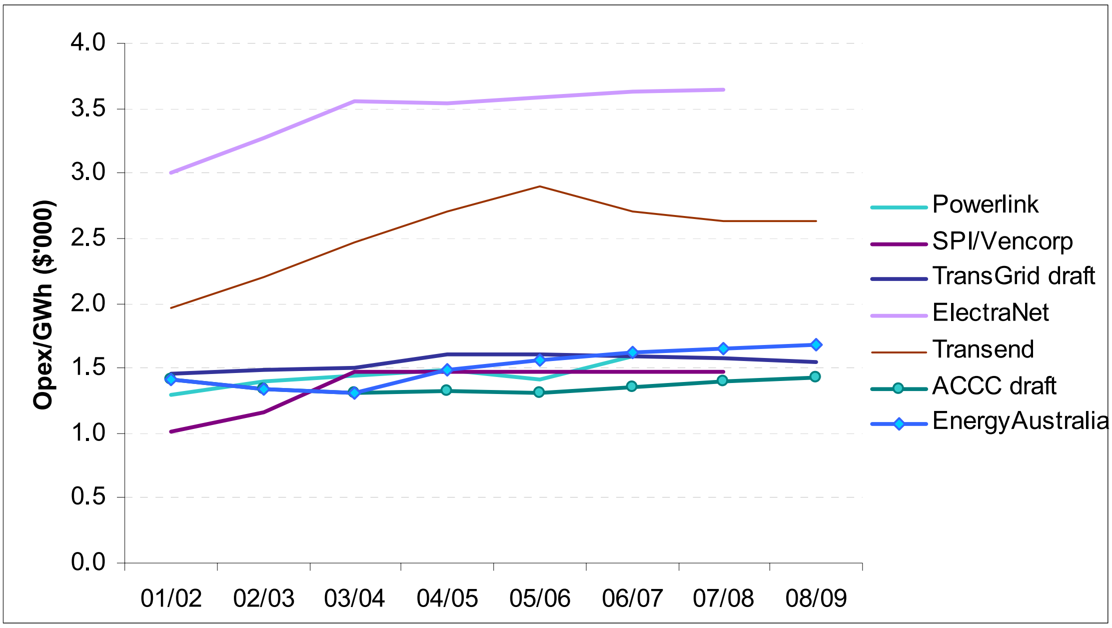
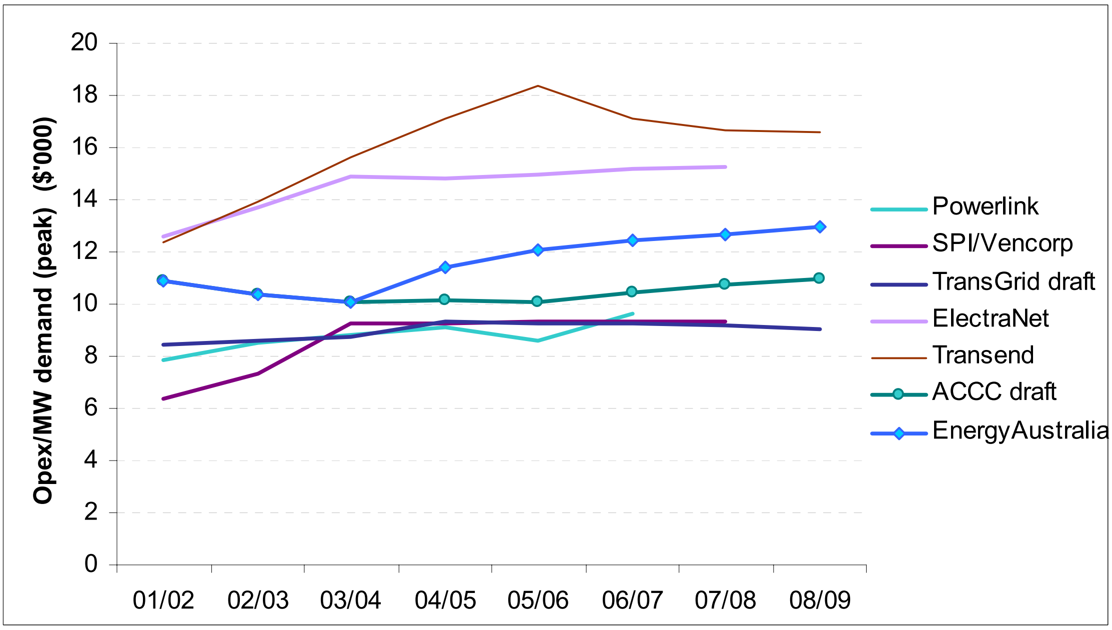


Figure 5.7 Comparison of TNSPs opex per MW



The ACCC recognises that differences in operating conditions and scale may explain why some ratios are higher or lower. As such, they can only provide a measure of reasonableness. Accordingly, the ACCC does not use benchmarking to establish opex allowances but rather as a guide to whether the allowance is within a reasonable range.

However, overall the ACCC considers that its benchmarking results show, particularly in relation to opex per asset base, opex per substation, opex per GWh and opex per MW, that the ACCC proposed opex allowance for EnergyAustralia is reasonable.

5.7 Conclusion

The ACCC is proposing an opex allowance of $114 million for EnergyAustralia over the 2004-2009 regulatory period. As set out above, it considers that an average annual opex figure of around $23 million is appropriate for EnergyAustralia.

Table 5.11 EnergyAustralia's opex ($m 2003/04)

	2004/05	2005/06	2006/07	2007/08	2008/09	Total
EnergyAustralia's proposal[1]	24.37	25.75	26.56	27.14	27.73	131.55
ACCC proposed opex[2]	**22.11**	**21.97**	**22.75**	**23.33**	**23.91**	**114.07**

1. EnergyAustralia's opex forecasts do not include debt raising costs as they were included in its WACC calculations.
2. ACCC proposed opex includes debt raising costs.

6. Cost of Capital

6.1 Introduction

One of the objectives of economic regulation is to provide a fair and reasonable rate of return on efficient investment (clause 6.2.2(b)(2) of the code). Clause 6.2.4(c)(4) of the code provides guidance by stating that the ACCC must have regard to the WACC of the transmission network.

The ACCC uses the risk adjusted rate of return required by investors in commercial enterprises facing similar business risks to establish the WACC for EnergyAustralia.

Electricity transmission is a highly capital intensive industry where return on capital generally accounts for about half of the revenue allowed. Relatively small changes to the cost of capital could have a substantial impact on the AR.

Therefore, correctly assessing the WACC is important because:

- if the return on equity is too low, the regulated network may be unable to earn sufficient returns to the owner. This could reduce the incentive to reinvest in the business
- conversely, if the return on equity is too high, networks may have a strong incentive to overcapitalise, thus creating inefficient investment
- AR translates into prices for users. Hence, a higher AR means higher prices for end users.

In the DRP[32] the ACCC outlines its view on the appropriate expression of the return on equity to be achieved, and how it is to be used for deriving the AR. This is summarised in statement S6.3:

> The ACCC will apply the nominal post-tax return on equity as a benchmark. The revenues will be calculated on the basis of the cash-flows associated with the regulatory accounts necessary to deliver this return after taking into account liabilities and the assessed value of franking credits based on existing tax provisions and foreshadowed tax changes due to occur during the regulatory period.

[32] ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenues*, 27 May 1999, p. 84.

For this decision, the ACCC has chosen to use the 'vanilla WACC' in which the parameters relating to business income tax are removed from the WACC formula:

$$WACC = r_e (E/V) + r_d (D/V)$$

where:

r_e	=	required rate of return on equity
r_d	=	cost of debt
E	=	market value of equity
D	=	market value of debt
V	=	market value of equity plus debt.

In doing so, the ACCC explicitly models the tax liabilities (i.e. interest expense and franking credits) of the TNSP in the cash flow model.

EnergyAustralia has adopted the ACCC's post-tax approach to setting the WACC, expressed in nominal terms, in its application.

The remainder of this chapter sets out the parameters in the WACC framework and assesses the issues identified in EnergyAustralia's application and submissions from interested parties. The ACCC's draft decision on each parameter and the appropriate WACC for EnergyAustralia is summarised in section 6.12.

6.2 The capital asset pricing model

The regulatory regime administered by the ACCC must provide for:

> a sustainable commercial revenue stream, which includes a fair and reasonable rate of return to *Transmission Network Owners* and/or *Transmission Network Service Providers* on efficient investment, given efficient operating and maintenance practices. (Clause 6.2.2 of the code.)

Various methods can be applied to estimate return on equity (r_e) as outlined under schedule 6.1(2.2) of the code - for example, price to earning ratio, dividend growth model and arbitrage pricing theory. However, the code indicates that the capital asset pricing model (CAPM) remains the most widely accepted practical tool to estimate the cost of equity.

The CAPM calculates the required return given:

- the opportunity-cost of investing in the market
- the market's own volatility
- the systematic risk of holding equity in the particular company.

The CAPM formula is:

$$r_e = r_f + \beta_e(r_m - r_f)$$

where: r_f = the risk free rate of return (usually based on government bond rates of an appropriate tenure)

(r_m-r_f) = the market risk premium (MRP) which measures the return of the market as a whole less the risk free rate

β_e = the relative systematic risk of the individual company's equity (equity beta)

The CAPM expresses the rate of return as the post-tax nominal return on equity.

However businesses are funded by equity and debt. Therefore by including the cost of debt we can derive the corresponding return on capital employed. This is known as the WACC (see section 6.1). The determination of the WACC requires several parameters which are discussed in further detail below.

6.3 Estimate of the risk-free interest rate

The risk-free rate measures the return an investor would expect from an asset with zero volatility and zero default risk. The yield on long-term Commonwealth government bonds is considered to be risk-free since the government can honour all interest and debt repayments.

6.3.1 Sampling period

In the CAPM framework all information used for deriving the rate of return should, in principle, be as up-to-date as possible at the time the decision comes into effect. In the case of interest rates and inflationary expectations, financial markets determine these on a continuous basis.

On this issue Statement S6.7 of the DRP states:

> The risk free rate will be normally based on a 40 day moving average covering the eight weeks prior to the reset date unless there is evidence to suggest that the current rate of the day represents a transition to a new level which is expected to be maintained.

6.3.2 Submissions by interested parties

Sampling period

EnergyAustralia proposes that a 10-day averaging period be used to estimate the risk-free rate.

Term of the risk-free interest rate

The ACCC received submissions relating to the selection of the risk-free bond rate from EnergyAustralia, the Energy Markets Reform Forum (EMRF) and the customers' group.

Their comments focussed on:

- whether the risk-free rate should align with the life of the asset or the regulatory period
- the recent GasNet tribunal decision[33].

Alignment of the risk-free rate with the life of the asset or the regulatory period

EnergyAustralia argues that the 10-year bond rate should be used in its revenue cap reset. In the Network Economics Consulting Group's (NECG) report for EnergyAustralia, they contend that in adopting the length of the regulatory period as the proxy for the bond maturity, the ACCC is basing the risk-free rate on a different time variable than the MRP, for which estimates are based on the 10-year bond rate.

EnergyAustralia and the EMRF believe that the term of the MRP and bond rate maturity should coincide. They believe that if a 5-year bond rate is used as the risk-free rate then the MRP associated with the shorter term bond rate should be used.

The customers' group states that, given the five year regulatory cycle, it is more appropriate for five year bond rates to be used as refinancing can occur to coincide with the regulatory cycle. They believe that the risk-free rate being set with reference to the bond rate yield consistent with the investment horizon is spurious as it ignores the fact that refinancing of debt can be readily undertaken in a financially mature market like Australia.

Consistency with the recent GasNet tribunal decision

The EMRF has referred to the recent GasNet decision in which the Australian Competition Tribunal (Tribunal) supported the view that the risk-free rate should be the 10-year bond rate. However, the EMRF notes that the Tribunal did not comment on what adjustments should be made to other factors which modify this basic risk free input, such as the debt margin, the MRP, the debt beta and equity beta. In accepting the Tribunal's decision, the EMRF suggests that the ACCC adjust other input parameters to the CAPM formula in order to not reward returns which are not in keeping with benchmarking.

6.3.3 ACCC's considerations

Sampling period

The ACCC is aware of the inherent limitations associated with using either an 'on the day' rate or a 'historical average' in calculating the risk-free rate.

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[33] Australia Competition Tribunal 23 December 2003.

The financial theory underlying the CAPM explicitly specifies the use of *ex ante* returns. Using an on the day rate gives the best estimate of ex-ante returns. Therefore theoretically on the day rate is more appropriate.

However, an on the day rate reflects short-term fluctuations which may differ from the long-term trend. Such market volatility can be minimised by averaging rates over some time before the start of the regulatory period. Several regulators have traditionally used an average rate as the risk-free rate.

In the DRP the ACCC suggested a 40-day moving average and used it in several of its earlier regulatory decisions. However, more recently, the ACCC has adopted a 10-day averaging period in its *Tasmanian*[34], *Victorian*[35] and *South Australian*[36] revenue cap decisions.

The ACCC, therefore, accepts EnergyAustralia's proposal to use a 10-day moving average.

Term of the risk-free interest rate

The WACC is calculated at each revenue reset and is maintained throughout the regulatory period. Hence, the term for the risk-free interest rate, which is a component of the WACC, should match the length of the regulatory period. In the case of EnergyAustralia's revenue reset, the regulatory period is five years.

In previous revenue cap decisions, the ACCC has used government bond yields with terms matching the regulatory period as the proxy risk-free rate because:

- the regulatory framework seeks to provide an efficient return on the capital
- the regulatory asset value is supported by the expected cash flows during the regulatory period.

Some interested parties support the view of using the risk-free interest rate which matches the length of the regulatory period. Alternatively, other interested parties believe that bond rates with terms matching the life of the assets should be used. Transmission assets have long effective lives, far exceeding the term of the most traded Australian bond with the longest maturity period (i.e. 10 years). These parties suggest that 10-year bond yields should be used in the CAPM formula. Other Australian state regulators also use a 10-year bond rate.

In December 2003, the Tribunal handed down its decision on its review of the ACCC's tariff determination for transportation services on GasNet's Victorian natural gas transmission network.

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34 ACCC, *Tasmanian Transmission Network Revenue Cap 2004-2008/09*, 10 December 2003

35 ACCC, *Victorian Transmission Network Revenue Caps 2003-2008*, 11 December 2002.

36 ACCC, *South Australian Transmission Network Revenue Cap 2003-2007/08*, 11 December 2002.

Although the ACCC used a 5-year rate, the Tribunal accepted GasNet's approach to calculating the risk-free rate on the basis of a 10-year government bond rate. Following this decision, the ACCC welcomed the clarification provided by the Tribunal and stated that it would be guided by this finding in its future regulatory decisions.

Accordingly, due to this legal precedent the ACCC proposes to accept EnergyAustralia's request to use the 10-year bond rate as a proxy for the risk-free rate.

Maturity dates on the nominal and indexed bonds rarely correspond and require realignment using either interpolation or extrapolation, i.e. by estimating the rate at a given moment from a 'line of best fit'. The ACCC has used this approach in all of its revenue cap decisions, which is also consistent with jurisdictional regulatory decisions.

At the time of this draft decision, the nominal 10-year bond rate, ten-day moving average for Commonwealth government bond rates results in a risk free rate of 5.89 per cent.

6.4 Expected inflation rate

The expected inflation rate is not an explicit parameter in the return on equity calculation. It is a component of the risk-free rate (which has implications for the cost of both debt and equity), that can be estimated by the:

- difference between the nominal and indexed bond yields, or
- Commonwealth Treasury's inflation forecasts (based on its modelling).

Statement S6.11 of the DRP states:

> The forecast inflation rate will be deduced from the difference in the nominal bond rate and inflation indexed bond rates, and will be deduced for the term corresponding to the duration of the regulatory period. Alternatively, official inflation forecasts may be used.

For this draft decision, the ACCC forecasts inflation of 2.44 per cent per annum based on the Fisher equation (difference between nominal and indexed bond yields).

6.5 Cost of debt

The cost of debt on commercial loans is the debt margin added to the risk-free rate as illustrated by the formula:

$$r_d = r_f + d_m$$

where:

r_d = the cost of debt

r_f = the risk free rate of return

d_m = the debt margin.

The debt margin varies depending on the entity's gearing, credit rating and the term of the debt. Applying the cost of debt to the asset base, using the assumed gearing, will generate the interest costs for regulatory purposes.

Statement S6.10 of the DRP states:

> The ACCC will estimate the cost of debt for a firm conforming to the financial structures implied by the regulatory accounts in consultation with relevant finance agencies.

6.5.1 Submissions by interested parties

EnergyAustralia states that adopting a credit rating of 'BBB+' for a utility company with benchmark gearing of 60 per cent would be consistent with market observations. Therefore, it requests a debt margin of 135 basis points above the nominal risk-free rate.

6.5.2 ACCC's considerations

In considering an appropriate debt margin for an entity, the ACCC adopts industry-wide benchmarking, thus offering an incentive to minimise inefficient debt financing. This is consistent with the DRP.

Asset backing influences the credit rating of an entity. That is, the greater the debt to asset/equity ratio, the greater the risk and, therefore, the debt margin (other things being equal).

When calculating the debt margin, the ACCC considers the appropriate benchmark credit rating of the TNSP and the (market) debt margin associated with that rating.

The ACCC prefers to use a benchmark rather than an actual credit rating, as the credit-worthiness of the entity is partly under managerial control.

The ACCC considers relevant Australian electricity transmission and distribution companies should be used as the basis for a benchmark. Table 6.1 sets out the long term credit rating for 9 Australian electricity network companies that have been assigned a credit rating by Standard and Poor's. It shows that EnergyAustralia has a long term rating of 'AA' and an actual gearing of 51.4 per cent.

Table 6.1 Credit ratings of electricity companies

Company	Long-term rating	Actual Gearing (%)
Ergon Energy	AA+	49.3
Country Energy	AA	68.3
EnergyAustralia	AA	51.4
Integral Energy	AA	51.3
SPI PowerNet	A+	79.8
Citipower Trust	A-	20.6
ETSA Utilities	A-	63.5
Powercor Australia	A-	39.7
ElectraNet	BBB+	72.6

Source: Standard and Poor's, *Australian Report Card Utilities*, March 2004

Table 6.1 also shows that the average credit rating of these entities is about 'A' and their average gearing is about 55 per cent which is close to the benchmark of 60 per cent.

Standard and Poor's has stated that the 'A' rated entities are generally stable network or transmission businesses.[37] FitchRatings has also stated that:

> ...the transmission company should enjoy stronger credit ratings than other players in the electricity chain, because of the strong regulatory environment and low operating risks currently evident in Australia.[38]

Accordingly, the ACCC considers that an 'A' credit rating represents an appropriate proxy for the benchmark electricity transmission company. This is consistent with the ACCC's previous revenue cap decisions.

Having established a credit rating, a debt margin can be determined. The debt margin should reflect the prevailing market rates for debt issues at the benchmark maturity and credit rating for the regulated entity.

The ACCC acknowledges that the 10-year bond rate can be used as a proxy for the risk-free rate. Therefore the ACCC considers that the term of the relevant corporate bond rate should also match the term of the risk-free rate used. For this draft decision, the current 10-day moving average benchmark spread over the government bond yields, for 'A' rated corporate bonds with a maturity of ten years, is 87 basis points[39]. Combined with the nominal risk-free rate of 5.89 percent, it suggests a nominal cost of debt figure of 6.76 percent for use in the WACC estimate.

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[37] Standard and Poor's, *Australian and New Zealand Electric and Gas Utilities Ripe for Rationalization*, May 2002.

[38] FitchRatings, *Australian Electricity Sector - At That Awkward Adolescence Stage*, March 2004, p.40.

[39] CBASpectrum website: www.cbaspectrum.com

6.6 Debt raising costs

To raise debt, a company has to pay debt financing costs over and above the debt margin. Such costs are likely to vary between each debt issue, depending on the borrower, lender or market conditions.

According to a consultancy undertaken by Macquarie Bank on behalf of the ACCC, TNSPs often incur advisory fees, agency fees, arrangement fees, credit rating costs and syndication expenses.[40] In addition, TNSPs may also face other costs, such as dealer swap margins to transfer from floating to a fixed rate facility.

6.6.1 Submissions by interested parties

EnergyAustralia argues that 12.5 basis points should be allowed to account for debt raising costs. This is consistent with the ACCC GasNet 2002 decision.

6.6.2 ACCC's considerations

The ACCC considers that TNSPs should be provided an allowance for debt raising costs. A benchmark, reflecting current market costs, needs to be established to determine a reasonable allowance.

Information provided by a number of commercial banks indicated that debt raised on capital markets is likely to incur fees in the range of 8-12.5 basis points per year in addition to the debt margin.

Consistent with its recent Tasmanian revenue cap decision, the ACCC considers an allowance of 10.5 basis points per year for debt raising costs as a reasonable benchmark for a TNSP. This is included as part of opex (see section 5.5.2 of chapter 5) because it is an identified cost category.

The allowance for debt raising cost is about $0.41 million per year on average over the regulatory period. This is based on an opening RAB of $628.6 million and the assumed benchmark gearing ratio of 60:40.

The ACCC notes that the practice of allowing debt raising costs is relatively new. Therefore the ACCC will examine this approach in light of new information in its future revenue cap decisions.

6.7 Market risk premium

The MRP is the margin above the risk free rate of return that investors expect to earn if they held the market portfolio. That is, the return of the market as a whole less the risk-free rate:

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[40] Macquarie Bank, *Issues for debt and equity providers in assessing greenfields gas pipelines, report for the ACCC*, May 2002, pp. 16, 21.

$$MRP = r_m - r_f$$

Statement S6.8 of the DRP states:

> The ACCC will adopt what it perceives to be the accepted value of the market risk premium available at the time of the regulatory decision.

Under a classical taxation system, conventional thinking suggests a value for the MRP of around 6 per cent.

Determination of the return on capital for a regulated business (by multiplying the WACC to the RAB) is a forward-looking process. However estimates of the future cost of equity are not readily available. Practical applications of the CAPM therefore rely on the analysis of historic returns to equity when estimating the MRP.

6.7.1 Submissions by interested parties

EnergyAustralia proposes an MRP of 6 per cent in its application. It argues that, given clear and well-established historical precedent, the most appropriate MRP to adopt is 7 per cent and there is no case for an MRP below 6.5 per cent. However, in the context of recent regulatory precedent and the alignment of regulators on this issue, EnergyAustralia recommends that an MRP of 6 per cent be adopted.

Conversely, the EMRF argues that the historical MRP has declined over recent times, due to fundamental changes occurring in the competitive environment now operating in Australia. The EMRF and the customers' group contend that, as CAPM is intended to be a forward looking model for setting regulated returns, the use of historical average figures does not adequately reflect the current and expected future conditions.

The EMRF's analysis shows that over recent years the MRP has averaged 3.0-3.3 per cent, which is consistent with the recent surveys of Mercer Consulting.

The customers' group believes that recent regulatory decision using an MRP of 6 per cent grossly inflate the returns on equity above the level required by the market. They believe that Australian regulators persist with decisions that suggest Australian utilities are less efficient and more costly to finance than their UK and US counterparts. They argue that these outcomes may well be the result of overly-cautious regulation, or regulatory error, and there is a real possibility that regulators are contributing to a reduction in the competitiveness of the Australian economy.

6.7.2 ACCC's considerations

The ACCC's assessment of the MRP, though based on more traditional views using a historical MRP (ex-post measure), still remains at around 6 percent.[41]

This is consistent with the study by Associate Professor Lally for the ACCC, which recommended an MRP of 6 per cent.[42]

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[41] There appears to be consensus that the MRP cannot easily be predicted over shorter periods and is likely to have poor statistical properties.

The Allen Consulting Group (ACG) recently completed a study on behalf of the ACCC, which also analysed the factors that impact on the magnitude of the MRP to provide insight into the level of Australia's MRP relative to markets in other advanced economies.[43] Based on the evidence presented which includes an analysis of international trends in MRP, the ACG concluded that:

> …there is no justification for applying an MRP different from 6 per cent, as is the practice of Australian regulators.

The ACCC accepts that some overseas regulators (UK) have used an MRP of about 3.5 per cent. However, there is reason to believe that the MRP in Australia might be different as:

- despite global markets, a perception of segmented stock markets still exists and investors may require a higher premium to invest in the Australian market
- a domestic CAPM version is used in estimating the required cost of equity.

Further, in the absence of any adjustment for differences in financial market conditions and institutional arrangements between countries, the ACCC considers that such a direct comparison between Australian and UK MRP figures (in regulatory decisions) is subject to some uncertainty.

A number of surveys have supported the ACCC's MRP estimate. For example, the Jardine Fleming capital markets survey on professional market practitioners' MRP expectations found that it was 5.87 per cent on average.[44] Other surveys have also found the expected future MRP is about 1-2 per cent below this figure. However, the ACCC considers that the evidence of an MRP of less than 6 per cent is not sufficiently conclusive at this time to warrant the application of an MRP of less than 6 per cent. However, the ACCC will continue to monitor the evidence.

6.8 Value of franking credits

Australia has a full imputation tax system under which a proportion of the tax paid by a company is, in effect, personal tax withheld at the company level.

The analysis of imputation credits and their impact on cost of capital in Australia is a developing field. The rate of use of tax credits or gamma (γ)may have an effect on the WACC (where a TNSP actually pays tax) and there is little doubt that franking credits have value (schedule 6.1(5.2) of the code):

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[42] Lally, *The Cost of Capital under Dividend Imputation*, June 2002, p.34.

[43] Allen Consulting Group, *Review of studies comparing international regulatory determinations*, 2004.

[44] Jardine Fleming Capital Partners Limited, *The Equity Risk Premium-An Australian Perspective*, September 2001.

> As the ultimate owners of government business enterprises, tax payers would value their equity on exactly the same basis as they would value an investment in any other corporate tax paying entity. On this basis, it would be reasonable to assume the average franking credit value (of 50 per cent) in the calculation of the network owner's pre tax WACC.

6.8.1 Submissions by interested parties

EnergyAustralia proposes the continued use of 0.5 for γ. It acknowledges that a point in the range between 0.30 and 0.50 for γ is well established in Australian regulatory decision-making.

The customers' group believes that a gamma of 0.5 is overly generous to these monopolies taking into consideration that the overall Australian market is 70 per cent domestically owned.

6.8.2 ACCC's considerations

The γ incorporates dividend payouts carrying imputation credits and the proportion of those credits that could be used. The ACCC has previously noted that there is no well founded basis for discriminating the selection of γ in favour of one type of investor over another. Such an approach may distort pricing outcomes on the basis of share ownership and would not take into account other tax advantages or disadvantages that may be available to investors.

There does not seem to be consensus among Australian academics and practitioners to adjust the rate of use of imputation credits. Given that the value of γ lies between 0 and 1.0, the ACCC prefers to maintain its position on γ of 0.5.

6.9 Gearing

The ACCC uses benchmark gearing in determining the WACC, rather than the actual gearing. Schedule 6.1(5.5.1) of the code states that:

> Gearing should not affect a government trading enterprise's target rate of return … For practical ranges of capital structure (say less than 80 per cent debt), the required rate of return on total assets for a government trading enterprise should not be affected by changing debt to equity ratios.

6.9.1 Submissions by interested parties

EnergyAustralia adopts the ACCC's benchmark gearing of 60 per cent in its application.

EMRF provides an analysis which highlights that implied gearing for a company is much higher than 60 per cent and that this comprises a mix of interest bearing debt (60 per cent of total capital) and non-interest bearing debt such as retained cash (15 per cent of total capital), with an equity element of 25 per cent of total capital. It argues that using a higher level of equity and not providing for non-interest bearing debt in the CAPM framework (incorrectly) inflates the WACC calculation.

6.9.2 ACCC's considerations

A firm's capital structure (expressed as gearing) is unlikely to affect its WACC according to the theory developed by Modigliani and Miller. This theory, however, is based on specific assumptions and, in reality, this is only true within reasonable boundaries, as at extremes the capital structure of a company could affect its WACC because higher gearing could result in increased risks for both debt and equity holders.

Typically regulators have assumed a gearing of 60 per cent (Table 6.2) in calculating the WACC. This WACC should still be applicable within reasonable range of actual gearing, say of 40-70 per cent (see above paragraph).

Table 6.2 Gearing levels adopted in regulatory decisions

Entity	Industry	Debt/Debt+Equity
ACCC (2003)	Electricity transmission	60 %
QCA (2001)	Electricity distribution	60 %
ESC (2000)	Electricity distribution	60 %
IPART (1999)	Electricity distribution	60 %
OTTER (1999)	Electricity distribution	50-70 %
OFGEM (1999)	Electricity distribution (UK)	50 %
IPART (1999)	Gas distribution	60 %
ACCC/ESC (1998)	Gas transmission	60 %

The ACCC's regulatory regime is both light-handed and incentive based. It sets the benchmarks allowing regulated entities to operate freely. The entities gain by performing better than the benchmarks and vice-versa. Accordingly, in the DRP the ACCC stated that it would not be using the actual gearing of a TNSP, but an appropriate benchmark instead.

A survey conducted by Standard and Poor's suggests that gearing ratios for transmission and distribution businesses should between 65 per cent and 55 per cent.[45]

The ACCC notes EMRF's comments but considers that it departs from the accepted practice of calculating the WACC based on a benchmark capital structure of equity and debt financing. The ACCC also notes that even retained cash would have some form of opportunity cost attached.

Therefore, on balance the ACCC has decided to adopt a benchmark gearing of 60 per cent.

[45] Standard and Poor's, *Rating Methodology for Global Power Companies*, 1999.

6.10 Betas and risk

The equity beta is a measure of the expected volatility of a particular stock relative to the market portfolio. It measures the systematic risk of the stock, that is, the risk that cannot be eliminated in a balanced and diversified portfolio.

Generally, the Australian stock index is used as a proxy for the market portfolio. An equity beta of less than one indicates that the stock has a low systematic risk relative to the market (the market portfolio beta being equal to one). Conversely an equity beta of more than one indicates the stock has a higher risk relative to the market.

Calculating equity betas for publicly listed companies is straightforward. A company's return is calculated by adding the dividend income to changes in the value of the stock. Then the company's return is compared to the market return. Market return is calculated in the same way, i.e. by adding the dividends and changes in values of all the companies listed on the stock exchange.

Calculating equity betas for unlisted firms is more complicated, as their returns cannot be calculated directly. Hence, conventional practice is to find the beta of a similar listed company or the average beta for the sector, and then adjust it.

For Australian regulated electricity networks even this approach is problematic, as very few similar stocks are listed.

The equity beta of a firm may also be dependent on its capital structure. Hence, to estimate the beta of a regulated firm, the beta of the comparable (listed) firm has to be adjusted for differences in capital structure.

Usually, practitioners start with the equity beta of a firm. Then by 'de-levering' it, to approximate a firm without debt (100 per cent equity), they arrive at the 'asset' or 'unlevered' beta.

The asset beta is common for all firms in a similar business. Equity beta for a particular level of gearing is obtained by 're-levering' the asset beta. While there are a number of levering formulae, the ACCC has consistently applied the formula developed by Monkhouse:[46]

$$\beta e = \beta a + (\beta a - \beta d)\left[1 - \left(\frac{rd}{1+rd}\right)(1-\gamma)Te\right]\frac{D}{E}$$

where:

β_e = equity beta

β_a = asset beta

β_d = debt beta

[46] ACCC, *Statement of Principles for the Regulation of Transmission Revenues*, 27 May 1999 pp. 79-81.

r_d = cost of debt

γ = gamma

T_e = effective tax rate

E = market value of equity

D = market value of debt.

The debt beta captures the systematic risk of debt, just like equity beta capturing the systematic risk of equity. The debt beta is used to de/re-lever equity beta. When converting asset betas to equity betas, one includes the systematic risk for debt in the capital structure. The debt beta shows the sharing of a firm's systematic risk between the systematic risk of equity and the systematic risk of debt.

6.10.1 Submissions by interested parties

EnergyAustralia adopts a debt beta of zero combined with an asset beta of 0.425 which, in accordance with the Monkhouse formula, provides a re-levered equity beta of 1.06. It argues that consideration of international beta values together with regulatory precedent suggests that a range of around 0.40-0.50 can be justified.

The EMRF suggests that the equity betas used by regulators assume that regulated businesses are "average". It notes that the market accepts that regulated businesses exhibit a "conservative" rating, recognising that while providing a lower return, there is enhanced certainty of return. The EMRF argues that the market assess regulated firms as exhibiting a lower equity beta than 1.0. It states that equity betas for regulated electricity transport businesses should be in the range of 0.5-0.7. The customers' group also takes this point of view, suggesting that an equity beta of less than 1.0 is required for a business with EnergyAustralia's risk profile.

6.10.2 ACCC's considerations

Equity Beta

The ACCC notes that in previous revenue cap decisions, an equity beta estimate of 1.0 was adopted. This suggests that the TNSP experiences the same volatility as the market portfolio in general. However, this is not consistent with the frequently held view that gas and electricity transmission businesses are less risky relative to the market, irrespective of their gearing. This view is predicated on the observation that the earnings of gas and electricity business are more stable than most other businesses in the market. Greater stability of cash flows suggests that the equity beta should be less than 1.0.

Asset Beta

The asset beta is only relevant within the de/re-levering process. The asset beta is simply the equity beta for a firm that is 100 per cent equity financed and has no debt in its capital structure. It is not observable and must be de-levered from the observable equity beta.

The ACCC has taken a consistent approach of using past regulatory decisions to determine an estimate of the asset beta. Table 6.3 lists the asset betas for recent regulatory decisions. The asset betas for electricity networks have been set between 0.35-0.5.

Table 6.3 Recent regulatory decisions on asset betas for electricity industry

Decision	Network Type	Asset Beta
ESC, price determination	Distribution	0.40
ACCC, Tasmania	Transmission	0.40
ACCC, NSW and ACT	Transmission	0.35-0.50
ACCC, Queensland	Transmission	0.40
IPART, NSW	Distribution	0.35-0.50
QCA, price determination	Distribution	0.45

Debt Beta

The ACCC notes that a debt beta estimate of zero has been applied in its previous electricity revenue cap decisions. The ACCC, in the past, considered that as the systematic risk of debt is low (given the risk of debt is primarily related to default risk) then a relatively low debt beta is appropriate and as such treated the debt beta as a residual parameter.

A report prepared by ACG for the ACCC also considered this information and suggested that an appropriate range for the debt beta would be between zero and 0.15.[47]

Nonetheless, as long as there is consistency in the value of the debt beta between the de-levering and re-levering process, its effect on the equity beta is generally negligible.

Consistent with previous practice and EnergyAustralia's application, the ACCC considers that an appropriate value for the debt beta is zero, in the de/re-levering process.

Estimating equity beta from market data

The ACG report suggested an equity beta for Australian gas transmission companies of just below 0.7 based exclusively on market evidence.[48] ACG also considered data for comparable businesses in the USA, Canada and UK. This data produced lower beta estimates and ACG concluded that this secondary information supports the view that Australian estimates are not understated. However, due to several qualifications to their analysis, ACG did not recommend relying only upon domestic empirical information.

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[47] ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities, final report for the ACCC*, July 2002, pp. 28-29.

[48] Ibid p. 46.

ACG recommended that a conservative approach to beta estimation be retained by Australian regulators with an equity beta estimate of 1.0. ACG however, noted that:

> In the future, however, it should be possible for greater reliance to be placed upon market evidence when deriving a proxy beta for regulated Australian gas transmission activities.[49]

As shown in Table 6.4, the ACCC has derived betas from comparable Australian firms based on September 2003 and December 2003 data from the Australian Graduate School of Management (AGSM). For calculation purposes, the ACCC has had regard to raw (unadjusted) beta estimates, the debt beta was set at zero, and the corresponding gearing levels were from Standard and Poor's.[50] The sample market beta estimates (average relevered beta of 0.16 in September 2003 and average relevered beta of 0.18 in December 2003) suggest that the ACCC has been generous, in terms of the equity beta, in its previous decisions.

Table 6.4 Sample betas

		September 2003 AGSM data			December 2003 AGSM data		
Company	**Gearing level**	**Unadjusted β_e**	**Delevered β_a**	**Relevered β_e**	**Unadjusted β_e**	**Delevered β_a**	**Relevered β_e**
Australian Pipeline Trust	66.60	0.35	0.12	0.29	0.36	0.12	0.30
Envestra	79.90	0.28	0.06	0.14	0.30	0.06	0.15
AlintaGas	49.20	0.33	0.17	0.42	0.37	0.19	0.47
Australian Gas Light	52.20	-0.07	-0.03	-0.08	-0.06	-0.03	-0.07
GasNet	67.20	0.05	0.02	0.04	0.05	0.02	0.04
Average	**59.50**	**0.19**	**0.07**	**0.16**	**0.20**	**0.08**	**0.18**

At the same time, the ACCC would like to be confident that the market derived beta would not systematically under compensate the TNSP. The ACCC considers that it may be premature to rely on market data exclusively when determining the equity beta.[51]

[49] Ibid, p. 43.

[50] Standard & Poor's, *Australia & New Zealand CreditStats*, June 2003.

[51] The data on betas of listed firms in the Australian Stock Exchange considered to be comparable for benchmarking a TNSP's proxy equity beta is limited. However in the future, expanded data on beta estimates for comparable firms may mean more weight should be placed on market estimates.

The ACCC is considering the merits of relying more on market data, in determining an estimate of the proxy equity beta for TNSPs, as part of the DRP review process. Thus future decisions may incorporate equity betas which reflect market information more accurately. Accordingly, for this decision the ACCC has maintained the beta values previously adopted. On balance, the ACCC considers that an equity beta of 1.0, while biased in favour of the service provider, is appropriate for EnergyAustralia. It should be noted however, that future decisions may place greater weight on contemporary market information in determining appropriate beta values.

Conclusion

EnergyAustralia's proposed equity beta of 1.06 suggests that it has a higher risk relative to the market portfolio. In past electricity decisions, the ACCC has consistently applied an equity beta of 1.0.

For the purposes of this decision, the ACCC has decided to adopt an asset beta of 0.4 and a debt beta of zero, which equates to an equity beta of approximately 1.0. However, in future, greater reliance on market data may be more appropriate in determining a proxy equity beta for TNSPs. This will be considered further in the process of finalising the DRP.

6.11 Treatment of taxation

The effective tax rate is defined as the difference between pre-tax and post-tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that lessen or defer tax liabilities. Although the tax rate on accounting income is always at the corporate rate, in any year the income assessable for tax purposes can be quite different from the net revenues available to the business.

The timing aspect and the fact that taxes are assessed on the basis of nominal income means that the prevailing inflation rate also has a significant impact on the effective tax rate.

In its early decisions, the ACCC applied the statutory company tax rate of 30 per cent. This was in the context of difficulties in determining a satisfactorily accurate long-term tax rate as part of the pre-tax real framework being used at the time. However, the capital-intensive nature of electricity utilities has historically meant that the effective tax rate for such networks has been less than the statutory tax rate.[52]

The ACCC considers that adopting the post-tax nominal framework which uses the effective tax rate can potentially generate more appropriate cost reflective revenue caps. Furthermore, the ACCC's WACC calculations require the derivation value of the effective tax rate.[53]

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[52] According to IPART calculations, the average effective tax rate paid by the NSW distributors amounted to 25 per cent in 1996/97 (see IPART, *The Rate of Return of Electricity Distribution Network - Discussion Paper*, November 1998, p.9).

[53] The Monkhouse formula is $\beta_e = \beta_a + (\beta_a - \beta_d)\ \{1 - [r_d/(1+r_d)](1-\gamma)T_e\}\ D/E$, where T_e is the effective tax rate.

6.11.1 ACCC's considerations

Based on the ACCC's approach to modelling the effective tax rate, the ACCC has derived an effective tax rate of 27.15 per cent.

6.12 Conclusion

The ACCC has carefully considered the values that should be assigned to EnergyAustralia's cost of capital, given the nature of its business and current financial circumstances. The parameter values adopted for the draft decision are shown in Table 6.5.

Table 6.5 Comparison of cost of capital parameters

Parameter	Draft decision	EnergyAustralia's proposal
Nominal risk-free interest rate (r_f)	5.89 %	5.55%
Expected inflation rate (f)	2.44 %	3.34 %
Debt margin (over r_f)	0.87 %	1.475 %
Cost of debt $r_d = r_f$ + debt margin	6.76 %	7.025 %
Market risk premium (r_m-r_f)	6.00 %	6.00 %
Gearing (D/V)	60 %	60 %
Value of imputation credits γ	50 %	50 %
Asset beta β_a	0.40	0.425
Debt beta β_d	0.00	0.00
Equity beta βe	1.00	1.06
Nominal post-tax return on equity	11.86 %	11.89%
Post-tax nominal WACC	6.84 %	6.95%
Pre-tax real WACC	6.94 %	7.47%
Nominal vanilla WACC	**8.80 %**	**8.97 %**

7. Total allowed revenue

7.1 Introduction

This chapter explains the ACCC's calculation of EnergyAustralia's AR from 1 July 2004 to 30 June 2009.

The ACCC's role as regulator of transmission revenues is limited to determining a TNSP's MAR. As shown below, the MAR is calculated by adding (or deducting) a financial incentive related to service standard performance and pass through amounts to (or from) the AR. Further information on how the financial incentive related to service standards is calculated can be found in chapter 8.

TNSPs are responsible for calculating the transmission charges payable by their customers in accordance with the principles contained in part C of chapter 6 of the code. TNSP's must notify customers of the transmission service prices that are to apply for the following financial year by 15 May each year for the purposes of determining distribution prices as outlined in part E of chapter 6.

The annual revenue that a TNSP recovers through these charges must not exceed the MAR set by the ACCC. Any over or under recoveries must be offset against a TNSP's revenues in the following year.

7.2 The accrual building block approach

The building block formula, below, is used to calculate the AR in the first year. The MAR is equivalent to the AR for the first year:

$$\begin{aligned} AR &= \text{return on capital} + \text{return of capital} + \text{opex} + \text{tax} \\ &= (WACC * WDV) + D + \text{opex} + \text{tax} \end{aligned}$$

where:

AR	=	allowed revenue
WACC	=	post-tax nominal weighted average cost of capital
WDV	=	written down (depreciated) value of the asset base
D	=	depreciation
opex	=	operating and maintenance expenditure
tax	=	expected business income tax payable

Each subsequent year's AR is calculated as follows:

AR_t = AR_{t-1} x (1 + CPI) x (1 – X)

where:

AR	=	allowed revenue
t	=	time period/financial year
CPI	=	actual CPI
X	=	smoothing factor

The following formula is used to calculate the MAR for each year. If a pass through is approved, the amount approved will be included in the MAR.

MAR_t = (allowed revenue) ± (financial incentive) ± (pass through)

$$= \left(\mathrm{AR}_t\right) \pm \left(\frac{(\mathrm{AR}_{t-1} + \mathrm{A}R_{\mathrm{t-2}})}{2} \times S_{ct}\right) \pm \textit{(pass through)}$$

where:

MAR	=	maximum allowed revenue
AR	=	allowed revenue
S	=	service standards factor (Appendix C)
t	=	regulatory period
ct	=	calendar year

7.3 EnergyAustralia's proposal

In its application, EnergyAustralia asked for a smoothed revenue of \$108 million in 2004/05, increasing to \$128 million in 2008/09. In 2003/04, EnergyAustralia's comparable AR is \$78 million.

EnergyAustralia notes that this 'P_0' adjustment is primarily the result of the inclusion of new assets in the transmission asset base. This has been caused by two factors:

- the construction of assets not envisaged at the time of the 1999-2004 revenue cap decision
- a number of assets which are now meeting the code definition of transmission assets due to system changes and which; therefore, must be moved from the distribution to transmission asset base.

EnergyAustralia states that the revenue stream that it is seeking over the 2004-2009 regulatory period will allow it to maintain its ageing network and undertake both new capital works and replacement of old elements of the network, thereby ensuring high quality of transmission services for its customers.

EnergyAustralia states that the higher revenue requirement is appropriate as it is entering a stage where higher levels of capital and operating expenditures are being undertaken.

7.4 EnergyAustralia's compliance with the 1999-2004 revenue cap

EnergyAustralia has informed the ACCC that due to the nature of pricing for EnergyAustralia's transmission customers which utilises a large fixed component, the revenue received is largely consistent with the allowed revenue for each year of the 1999-2004 regulatory period. In NSW, TransGrid calculates transmission prices for itself and EnergyAustralia. A monthly settlement occurs between EnergyAustralia and TransGrid to ensure that each TNSP is recovering its portion of the allowed revenue.

EnergyAustralia forecasts that the estimated balance on what it has charged customers for the 1999-2004 regulatory period is $560,000. This means that EnergyAustralia has overcharged customers by a small amount over the 1999-2004 regulatory period. However, the final balance for 2003/2004 is still to be calculated and any excess would need to be factored into setting prices for 2004/05.

7.5 Discount recovery

Clause 6.5.8 of the code allows for TNSPs to recover from other customers the amount of a discount on TUOS charges (general and common service charges), subject to ACCC approval in accordance with the discount recovery guidelines.

Where an application for approval of a discount recovery was made prior to publication of the discount recovery guidelines (3 May 2002) the code allows for the ACCC to approve the discount recovery at the time of the application.

Where applications for approval of a discount recovery have been made after 3 May 2002 the code requires that these discount recoveries are approved at each revenue reset. In these cases, the ACCC must include its assessment of the discount recovery application in its revenue decision, without breaching any confidentiality requirements.

In order to comply with the discount recovery provisions of the code, EnergyAustralia is required to include such information as is necessary to satisfy the ACCC that:

- where an application was made prior to 3 May 2002, the terms of the discount and amounts being recovered remain in accordance with any approval given
- where an application was made after 3 May 2002 there have been no substantial errors or omissions identified in the information provided at the time a discount recovery application was made.

The ACCC has not yet received the required information from EnergyAustralia, and will complete its assessment of discount recovery at the time of its final revenue cap decision.

7.6 Working capital

In its application, EnergyAustralia is proposing an allowance for working capital of approximately $1 million per annum, as outlined in Table 7.1 below.

Table 7.1 Proposed working capital revenue requirement ($m nominal)

	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Return on working capital	1.1	1.1	1.0	1.1	1.3	5.5

EnergyAustralia considers that at the time of the 1999-2004 revenue cap decision, the appropriateness for a return to be provided on the working capital employed in the efficient operations of a network business was not addressed. EnergyAustralia states that the approach in NSW is based on the payment cycle and having regard for the average trading terms of the businesses – in effect, the amount of time that payments and receipts are outstanding.

A paper prepared by the ACG[54] for the ACCC in March 2002 describes why it is not necessary to give a service provider an allowance for working capital.

ACG believes that the concern that an additional allowance in respect of working capital is required, can be interpreted as a concern that the simple formula adopted by the ACCC, when calculating the target revenue, is inappropriate. It implies that the implicit assumptions in that formula about timing of cash flow in respect of operating activities may not accurately reflect the true timing of cash flow within a given year, and so understate the opportunity cost associated with investors' funds.

ACG states that to claim that an additional allowance in respect of working capital is required, amounts to stating that within year timing assumptions for the share of revenue and costs associated with operating activities, implied by the simple target revenue formula used by the ACCC, are incorrect, and that the difference creates a material bias against the service provider.

ACG undertook empirical tests to assess the bias in the ACCC's target revenue formulae. The results of these tests show that the post tax revenue model (PTRM) formula results in a significant bias in the favour of the service provider. The use of this formula leads to average prices of 1.8 per cent higher than required. This bias in favour of the service provider remains, even if extreme assumptions are made about the timing of expenditure within the year.

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[54] AGC, *Working capital – relevance for the assessment of reference tariffs*, March 2002

These results imply that such an allowance of working capital is unnecessary. While there may be a (small) financing cost associated with operating expenditure, any shortfall from not including an allowance in respect of working capital is likely to be swamped by the favourable allowance provided in respect of capital assets under the PTRM target revenue formula.

Therefore, the ACCC's draft decision is to not allow a separate allowance for working capital.

7.7 Pass through events

Under the code the ACCC is required to administer an incentive-based form of regulation. Incentives are created for managers to pursue ongoing efficiency gains through controlling their expenditures. However, some costs are essentially uncontrollable by nature and therefore cannot properly be subject to the same incentive measures.

Cost pass throughs provide a mechanism for dealing with this problem. As an alternative to receiving an allowance in its cash flows, a TNSP may transfer the financial impact of the event to parties that are better placed to handle these costs.

The ACCC envisages that the range of potential pass through events will be limited. It seeks to achieve a balance between the interests of TNSPs and customers, with no windfall gains or losses accruing to TNSPs as a result of events beyond their control.

7.7.1 General operation of pass through mechanisms

In assessing a proposed pass through mechanism as part of a revenue cap, the ACCC is guided by, amongst other things, the objectives in clause 6.2.2, principles in clause 6.2.3 and mechanism in clause 6.2.4 of the code. These provisions suggest that, in general, pass through events should have the following characteristics.

- The event should be identified in advance with its scope precisely defined – this enables the following tests to be applied and is considered necessary for good, transparent regulation. A high degree of certainty is provided where the ACCC and the TNSP agree up front on the events to be covered by pass through arrangements.

- The event should be beyond the control of the TNSP – these are exogenous, unpredictable events, the cost of which cannot be built into the TNSP's expenditure forecasts, requiring an alternative mechanism to deal with them.

- The financial impact of the event should be material – these are the types of events that may occur infrequently but can have a significant financial impact on the business. Setting a materiality threshold limits the applications a TNSP can make, for the purposes of administrative efficiency.

- The event affects the TNSP, and not the market generally – systematic or market risk should be addressed in the WACC parameters.

- The financial impact of the event is better borne by parties other than the TNSP – by its nature, a pass through transfers the risk to other parties. This will only be appropriate where the TNSP cannot reasonably be expected to bear the risk itself, for example, in the case of uncontrollable events that may affect the commercial viability of the business.

The ACCC considers the following matters are, in general, important features of an efficient and equitable pass through mechanism.

- The pass through mechanism should accommodate both positive and negative amounts in the interests of both TNSPs and customers. Consequently, pass through reviews should be able to be initiated by both the TNSP and the ACCC.

- A 40 business day assessment period (which can be extended where necessary) to allow full assessment of pass through event applications, including public consultation where appropriate, to be undertaken by the ACCC.

- The provision by the TNSP of detailed documentary evidence in support of any pass through application. Sufficient detailed information must be provided which substantiates that the aggregate costs facing the TNSP have increased or decreased as a consequence of the claimed pass through event. Wherever possible, this information should also be placed in the public domain.

- All or part of the cost should not be passed on if the TNSP, through an imprudent act or omission, caused or aggravated the pass through event.

- A TNSP must annually (at least 50 business days prior to the start of the financial year) provide the ACCC with a copy of insurance premium invoices, irrespective of whether a pass through event application has been submitted in that year.

7.7.2 EnergyAustralia's pass through rules as originally proposed

EnergyAustralia proposes that a pass through mechanism would operate for five categories of events.

- A change in taxes event.

- An external event.

- A fees event.

- An insurance event.

- A regulatory event.

Pass through arrangements are part of EnergyAustralia's overall risk management strategy and are detailed in Attachment 13 of its revenue cap application.

7.7.3 Submissions by interested parties

The EMRF does not agree with the implementation of a cost pass through mechanism for unexpected costs. It considers that to allow this will take away any incentive by

EnergyAustralia to minimise operational costs and runs counter to the exposure within which businesses in a competitive environment operate. Where there is competition, there is no pass through of costs, as each enterprise seeks to maintain or enhance its market position.

Ergon Energy has concerns about unlimited pass through of costs during the regulatory period and considers that cost pass throughs should only be allowed in exceptional circumstances. A pass through should not be used to recover losses incurred as a result of poor management, growth forecasts or inadequate risk/insurance cover.

7.7.4 ACCC's considerations

The ACCC has assessed EnergyAustralia's proposals against the general considerations detailed above, which focus on events that are essentially uncontrollable, unpredictable, material in financial impact and that are particular to the TNSP itself. It is accepted that certain events are outside the control of EnergyAustralia and has considered EnergyAustralia's proposals in light of its recent Transend, Murraylink[55] and SPI PowerNet decisions. The ACCC approves the following pass through events, subject to the clarifications below.

- A change in taxes event.
- A terrorism event.
- An insurance event.
- A service standards event.

See Appendix A for the pass through rules. The precise wording of the pass through rules to be included in the revenue cap will need to be settled prior to the ACCC's final decision.

A change in taxes event

The ACCC approves the inclusion of a change in taxes event, subject to amendments, which have been made to the proposed definition of a relevant tax, in line with the ACCC's recent decisions. Under the definition of a relevant tax in clause 3.1, clauses (5) – (7) have been added as exclusions from the definition.

An insurance event

The ACCC approves the inclusion of an insurance event, subject to minor amendments in line with the recent Transend decision. The ACCC considers it appropriate for EnergyAustralia to explicitly state that the event applies only in the instance that it can demonstrate that it has taken all reasonable precautions and is in no way negligent.

In their application, EnergyAustralia claimed a self-insurance allowance for losses within deductibles in current insurance policies. The proposed allowance (of $20,000

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[55] ACCC, *Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue – Decision,* 1 October 2003.

per annum) related to the risk of bushfire liability to transmission assets (see section 5.5.2). The ACCC has determined that the allowance should not be included in the cash flows, but actual deductible expenditures should be included in the pass through mechanism as an insurance event.

Therefore, the definition of an insurance event in clause 3.1 has been amended to include a provision for losses within deductibles in relation to bushfire liability.

The ACCC also considers it relevant to insert a clause relating to provision of insurance information, at least 50 days before the start of a financial year (whether or not a pass through event has occurred) in accordance with general operation of the pass through mechanism.

The ACCC does not approve the following as pass through events:

An external event

The definition of an external event is ambiguous and broad in scope. As discussed above, in general, a pass through event must be identified in advance with its scope precisely defined. Hence, it is difficult to assess whether the external event is beyond the control of the TNSP, financially material, non-systematic, better borne by parties other than the TNSP and in line with code objectives and principles. It is also not clear that there is no overlap between the external event pass through and other risk management strategies, for which EnergyAustralia is already being compensated.

The scope of pass through events should be as specific as possible to ensure that the provision does not lead to later uncertainty over whether an event is admissible or not. For this reason, the ACCC does not include the external event pass through provision; but in lieu of this, will accept the more precisely defined terrorism event and application thereof, consistent with its recent decisions, as specified in Appendix A.

A fees event

The ACCC considers that any firm operating in the industry would face the same exposure to ongoing changes and improvements of the industry, including changes to licensing, memberships or contributions; hence, a fees event, as defined, would be systematic. It may also be imposed specifically for the purpose of changing the behaviour of the TNSP, such as an environmental levy.

Overall, the ACCC considers that the risk of a fees event is better borne by the TNSP rather than transferred to other parties. To allow a pass through may not provide the right incentives to the TNSP to make reasonable endeavours to accurately manage risks and make efficient decisions.

A regulatory event

The definition of a regulatory event, given by EnergyAustralia, is not sufficiently defined in accordance with the general operation of pass through mechanisms. The ACCC considers there is no reason to deviate from the ACCC's current service standards event definitions. As such, the ACCC approves the inclusion of a service standards event, subject to certain amendments to the definition (see Appendix A).

The ACCC considers that the initially proposed reference to costs in complying with obligations imposed by the ACCC should be excluded as such obligations are not sufficiently defined. In addition, EnergyAustralia's proposed wording of 3.1(1)(b) included:

> …including requiring EnergyAustralia to undertake any activity as part of the revenue capped transmission services in addition to those required to be undertaken at the time of the Determination.

This has been deleted as the ACCC considers that it has been covered under clause 3.1(1)(c) of the Service Standards Event definition.

General amendments to the pass through rules

In relation to the remainder of the proposed pass through rules, the ACCC agrees in principle, subject to certain amendments in line with recent decisions. These amendments are illustrated in the pass through rules in Appendix A.

In general, the ACCC considers that a pass through mechanism that accommodates both positive and negative amounts is appropriate.

The ACCC regards that rather than solely considering the financial impact or materiality of the pass through event on the TNSP in comparison to allowed revenue, it is also appropriate to consider the prudence of the TNSP's decisions and actions. That is, whether through any imprudent act or omission the TNSP has caused or aggravated the pass through event. Hence, the ACCC has excluded parts of EnergyAustralia's proposed wording of clause 2.3. In particular, those relating to insurance may be deemed to be within the control of EnergyAustralia.

In addition, some parts within clause 2.3 relating to insurance have been removed as the information is provided in and more relevant to clause 3.1 under the definition of insurance event.

The ACCC has excluded parts of clause 2.2 as proposed by EnergyAustralia as it considers that the remaining clauses within 2.2, as set out in Appendix A, are sufficient in setting out the guidelines under which the ACCC makes its decision.

7.8 ACCC's assessment of the building blocks

7.8.1 Opening asset base

To establish the appropriate return on capital, the ACCC modelled EnergyAustralia's asset base (over the life of the regulatory period) and WACC (estimated on the basis of the most recent market financial information).

As explained in chapter 3, the ACCC has determined the value of EnergyAustralia's asset base as at 1 July 2004 to be $628.6 million.

The roll forward methodology provided an aggregate opening RAB. To accurately model EnergyAustralia's revenue allowance for the 2004-2009 regulatory period, this aggregate value should be split into the individual asset classes as proposed by

EnergyAustralia in its (pro forma) application. However, the ACCC does not possess sufficient information to precisely calculate the individual asset class values consistent with the aggregate number. Therefore, for the draft decision the ACCC has had to estimate these. In finalising its decision, the ACCC will seek the necessary information from EnergyAustralia to enable it to precisely model the individual asset class values.

7.8.2 Capital expenditure

As explained in chapter 4, the ACCC considers that a capex allowance of $183.8 million (in real terms) is appropriate for the draft decision.

7.8.3 Depreciation (return of capital)

The ACCC used a straight-line depreciation method (based on the remaining life per asset class of existing assets and the standard life for new assets) to model economic depreciation. The resulting figures (referred to as return of capital) are shown in Table 7.2.

7.8.4 Operating and maintenance expenses

As explained in chapter 5, the ACCC has included an opex allowance of about $23 million per annum (in real terms) on average over the regulatory period.

7.8.5 Weighted average cost of capital

The ACCC's estimate of EnergyAustralia's WACC is explained in chapter 6.

The ACCC has considered the nature of EnergyAustralia's business and its current financial circumstances in establishing the WACC. It notes that, although there is a well recognised theoretical model for establishing WACC, there is less than full agreement on the precise magnitude of the various financial parameters used.

The ACCC has applied a post-tax nominal return on equity of 11.86 per cent, which equates to a nominal vanilla WACC of 8.80 per cent (chapter 6 Table 6.5).

7.8.6 Estimated taxes payable

Tax estimates relate to the network's regulated activities only. The ACCC anticipates that EnergyAustralia would be paying income tax during the regulatory period, based on EnergyAustralia's tax depreciation profile. The ACCC's assessment of taxes payable are based on the 60 per cent gearing assumed in the WACC parameters as opposed to EnergyAustralia's actual gearing. The ACCC's estimates of EnergyAustralia's tax payments are as shown in Table 7.2.

7.9 Conclusion

The ACCC proposes an unsmoothed revenue allowance that increases from $91.3 million in 2004/05 to $112.7 million 2008/09, as shown in Table 7.2.

Table 7.2 EnergyAustralia's unsmoothed AR ($m nominal)

	2004/05	2005/06	2006/07	2007/08	2008/09
Return on capital	55.3	58.3	60.6	63.7	66.1
Return of capital	10.6	11.6	13.0	14.2	15.4
Operating expenses	22.6	23.1	24.5	25.7	27.0
Estimated taxes payable	5.4	6.5	7.1	7.7	8.4
Value of franking credits	(2.7)	(3.3)	(3.5)	(3.8)	(4.2)
Unadjusted revenue allowance	**91.3**	**96.2**	**101.7**	**107.5**	**112.7**

The ACCC has determined a smoothed revenue allowance for EnergyAustralia that increases from $91.3 million in 2003/04 to $113.1 million in 2008/09, as shown in Table 7.3.

The draft decision is based on forecast inflation of 2.44 per cent per annum and applies a smoothing factor of -2.99 per cent. EnergyAustralia must adjust the opening revenue figures annually by actual inflation (the eight weighted capital city CPI).

Table 7.3 EnergyAustralia's smoothed AR ($m nominal)

	2003/04[1]	2004/05	2005/06	2006/07	2007/08	2008/09
Smoothed AR	**78.08**	**91.27**	**96.28**	**101.58**	**107.16**	**113.05**

1. Final year of 1999-2004 revenue cap decision

The final MAR will be determined by adding (or deducting) to the AR the service standards incentive (or penalty) and any allowed pass through amounts.

This revenue cap covers transmission services defined by the code and associated activities to be regulated by the ACCC, provided by EnergyAustralia.

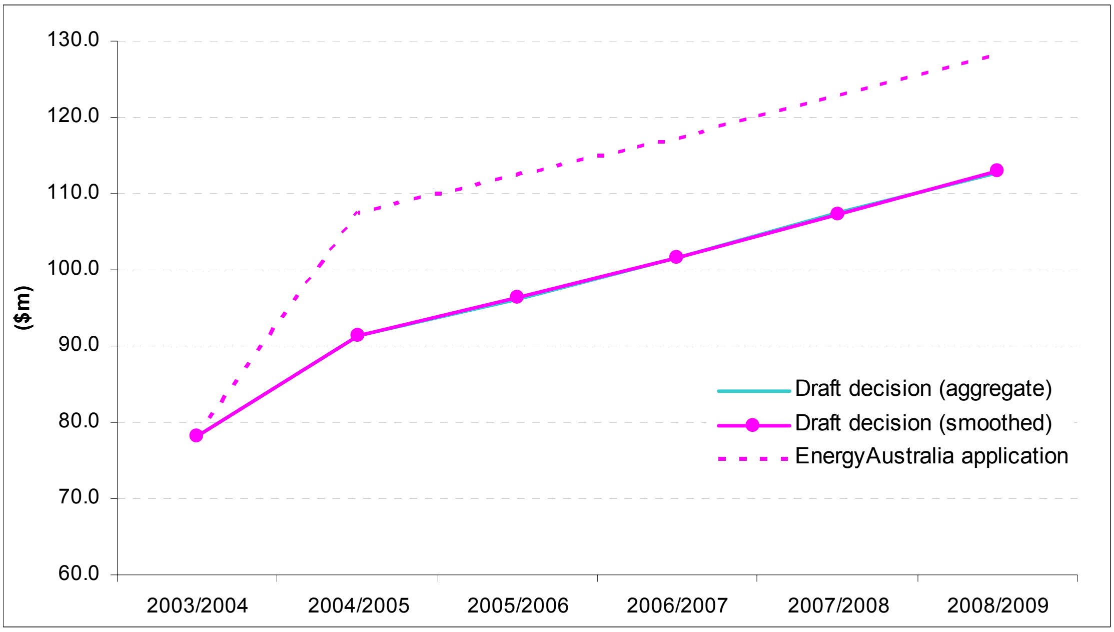
The revenue increase over the regulatory period consists of:

- an initial increase of about 16.9 per cent (nominal) in the first year; mainly as a result of increases in the asset base from:
    - assets moving from distribution to transmission, which accounts for the majority of the increase between 2003/04 and 2004/05. In fact, excluding these assets from the asset base the first year increase would only be 3.7 per cent (nominal).
    - capex incurred in the 1999-2004 regulatory period.

- a subsequent increase of around 5.5 per cent per annum (nominal) on average during the remainder of the regulatory period (mainly as a result of the large capex program the ACCC has provisionally adopted while developing an ex-ante capex framework for the final decision).

Figure 7.1 compares the revenue proposed by EnergyAustralia in its application with that allowed by this draft decision (both smoothed and unsmoothed).[56]

Figure 7.1 Revenue comparison 2003/04 to 2008/09 ($m nominal)



The ACCC considers that the total revenue it has allowed will not adversely affect the financial standing of EnergyAustralia's business. Appendix B contains the ACCC's examination of EnergyAustralia's likely credit rating under the revenue cap.

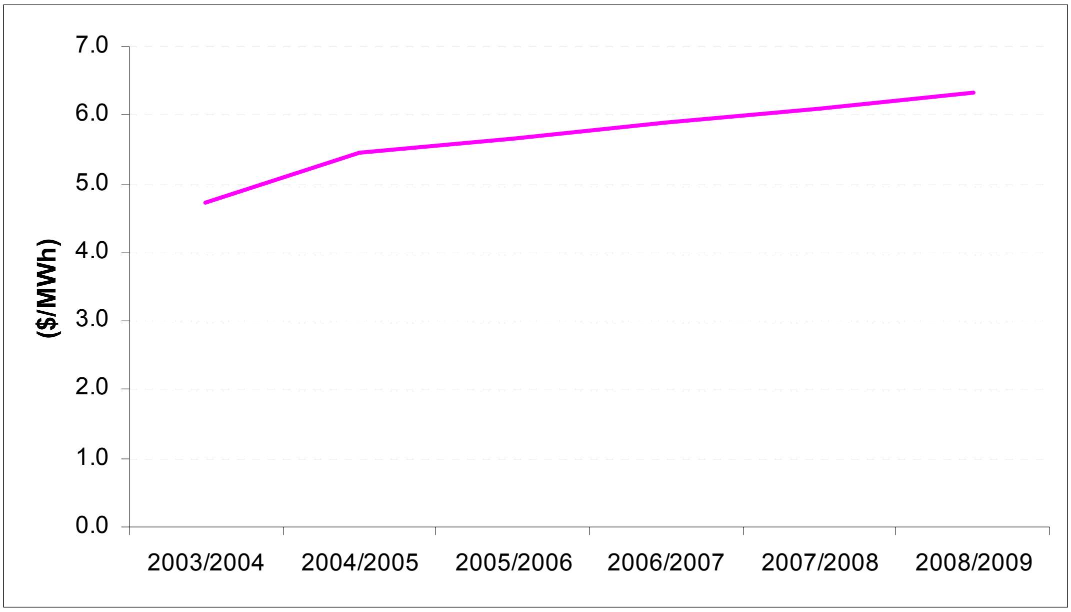
Impact on transmission charges

Figure 7.2 shows the resulting price path of this draft decision over the regulatory period. The indicative 2004/05 price path represents a 15 per cent increase over 2003/04 and will average an increase of 4 per cent (nominal) over the subsequent years.

The ACCC estimates that its draft decision will result, on average, in a 6 per cent per annum increase (nominal) in transmission charges over the regulatory period. Transmission charges represent approximately 10 per cent of end user electricity charges.

[56] The 2003/2004 revenue of $78.08 million excludes the transfer of additional assets to EnergyAustralia's opening RAB for 2004/2005.

Figure 7.2 Illustrative price path 2003/04 to 2008/09 ($/MWh nominal)



8. Service Standards

8.1 Introduction

This chapter explains the ACCC's calculation of EnergyAustralia's service standards for the 2004-2009 regulatory period. It sets out the relevant requirements of the code, and analyses a number of issues that were raised in EnergyAustralia's application. GHD's findings are set out in section 8.3 and submissions that were received from interested parties are discussed in section 8.4. The ACCC's draft decision is set out in section 8.6.

TNSPs cannot increase their revenues above the MAR set by the ACCC. Therefore, the only way TNSPs can increase their profits (on regulated activities) is by reducing costs. Such cost reductions could result in a decline in service quality which can impose much larger costs on other market participants.

Clause 6.2.4(c)(2) of the code recognises that the ACCC determines a revenue cap on the services that the TNSP provides and the level of service provided. Clause 6.2.4 states:

> In setting a separate revenue cap to be applied to each Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) in accordance with clause 6.2.4(b), the ACCC must take into account the revenue requirements of each Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) during the regulatory control period, having regard for:
>
> (1) …
>
> (2) the service standards referred to in the Code applicable to the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) and any other standards imposed on the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) by any regulatory regime administered by the ACCC or by agreement with the relevant Network Users;
>
> (3) …

In November 2003, the ACCC released its service standards guidelines.[57] This performance incentive scheme aims to reduce the incentive for TNSPs to achieve cost reductions at the expense of other market participants. It is based on five performance indicators, of which three are currently operational for EnergyAustralia. It is preferable that the average performance during the previous three to five years becomes the benchmark.

[57] ACCC, *Statement of Principles for the Regulation of Transmission Revenues, Service Standard Guidelines - Decision*, 12 November 2003.

TNSPs are rewarded for improvements over performance targets and penalised for deteriorations. The maximum reward or penalty is currently set at 1 per cent of the AR. Overall the scheme is designed to have an expected value of zero.

The ACCC's guidelines are based on a consultancy report produced by SKM.[58] Both documents can be found on the ACCC's website. SKM identified the two measures which are applicable to EnergyAustralia – transmission circuit availability and average outage duration. SKM recommended a target of 95.5 minutes for EnergyAustralia's transmission circuit availability. This target incorporates the ± 1 per cent financial incentive. The measure of average outage duration was recommended for data collection purposes only.

8.2 Application

In its application EnergyAustralia argues that, prior to the performance targets being set, an appropriate amount of data should be available upon which to base an estimate of future performance. EnergyAustralia states that it supports the ACCC's proposal to link performance service standards with financial rewards and penalties. However, EnergyAustralia claims that its transmission network is different to those operated by other TNSPs and many of the service standards envisaged for regional TNSPs are not relevant to EnergyAustralia. It believes that the use of industry benchmark would be inappropriate for EnergyAustralia given these differences.

8.2.1 Transmission circuit availability

EnergyAustralia has only collected availability performance data since 2000/01 using a manual process. The data available relates to transmission feeders only and EnergyAustralia states that SKM's recommended target of 95.5 minutes was based on data for a single year (2000/01) and future transmission circuit availability performance is expected to differ from that year. This is due to:

- the inclusion of transformers and reactive plant, in accordance with the proposed standard definition
- the inclusion of significant lengths of new 132kV lines and other equipment, resulting from the re-classification of some assets from distribution to transmission during the period of the current determination.

EnergyAustralia considers that the above points make the proposed target of 95.5 minutes invalid and propose that at least three years data using the standard definition of availability should be collected before availability targets are established.

EnergyAustralia submitted a further 2 years data (shown in Table 8.1) for its overall availability of its transmission feeders.

[58] SKM, *Transmission Network Service Providers – Service Standards*, March 2003.

Table 8.1 Availability

	2000/01[59]	2001/02	2002/03
Transmission feeders	96.55	94.60	96.30

EnergyAustralia is seeking the ACCC's agreement to the provision of availability data in the current form (i.e. not including availability of transformer or reactive plant). Should the ACCC insist on the inclusion of reactive plant and transformer information, EnergyAustralia claims it will need to implement systems and processes to record this data.

8.2.2 Average outage duration

EnergyAustralia states that the second performance measure, average outage duration, is not an appropriate measure and should not be adopted during the 2004-2009 regulatory period because:

- the restoration time for equipment will generally not impact on customer outcomes, due to the inherent high level of security in the design of the system
- the inherent repair times of EnergyAustralia's equipment are much more significant than for other TNSPs due to the large amount of cables in EnergyAustralia's system. To reduce the repair time on cables, EnergyAustralia claims it would require large capital investments which are not the objective of the present incentive mechanism.

8.3 Consultant's report

8.3.1 Basis for review

In undertaking this review, GHD evaluated the measures proposed by SKM and the available data received from EnergyAustralia against its actual performance over the 1999-2004 regulatory period to review the reasonableness of the proposed measures. When developing a recommended set of service standards, GHD took into account items that are expected to impact upon the performance of EnergyAustralia against the proposed measures in the 2004-2009 regulatory period.

8.3.2 Analysis of historical data

GHD provided a comparison of the performance of EnergyAustralia against the proposed measure of transmission circuit availability; however this is limited due to the lack of available data. Table 8.2 summarises the data made available within the 1999-2004 regulatory period.

[59] Previously submitted data that was used for SKM's review.

Table 8.2 Historic performance of EnergyAustralia

Measure	1999/00	2000/01	2001/02	2002/03	2003/04
Transmission circuit availability (%)	NA	96.55	94.60	96.30	NA
Average outage duration	NA	NA	NA	NA	NA

NA = Not Available

8.3.3 Summary of GHD's findings

GHD's findings are summarised as follows:

- *Limited data is available.* The data provided is insufficient to set substantial, restrictive service standards.
- *Target proposed by SKM of 95.5% transmission circuit availability*.
- *No data available for average outage duration measure,* however SKM recommend that data be collected as this may be a suitable future measure of EnergyAustralia's performance. GHD also recommends that this data be collected.
- *No caps, collars or deadbands proposed by EnergyAustralia.* A proposed incentive scheme with cap, collar and variable deadband has been proposed, with an increased target level of 96.1% and asymmetric reward/penalty loading.

8.3.4 Alternative performance incentive scheme

Based upon the available information and taking into consideration the limited historical data available, GHD recommends the configuration of caps, collars and deadbands shown in Table 8.3 for the 2004-2009 regulatory period.

Table 8.3 Service standards proposed by GHD

Performance measure	Unit of measure	Revenue at risk	Collar	Dead band knee 1	Target	Dead band knee 2	Cap
Transmission circuit availability	%	1	95.3	-	96.1	-	96.7
Average outage duration	Data to be measured by EnergyAustralia during 2004-2009 regulatory period						

These proposed service standards would represent a relatively straightforward basis of assessment for the 2004-2009 regulatory period. GHD proposes that given only one measure has some historical data available, using the single measure is considered to be the most appropriate approach. GHD believes that setting a higher target is reasonable based upon the historic data available.

8.4 Submissions by interested parties

The ACCC received submissions regarding EnergyAustralia's service standards from the EMRF, Ergon Energy, the Energy Retailers Association of Australia Incorporated (ERAA) and the customers' group.

Ergon Energy recognises that the service standards regime being developed by the ACCC is in its infancy and that consultation with market participants is continuing. Accordingly, it states that it is essential for revenue determinations to be capable of accommodating the development of a more robust and sophisticated service standard regime during the determination period.

The ERAA states that the service standards for all network service providers should be:

- directed at market outcomes that benefit electricity users
- applied during periods of system stress when performance matters
- universally applied to all TNSPs both in scope and level[60]
- focussed on best practice in the industry
- subject to Force Majeure provisions that are consistent with general industry practice.

[60] As EnergyAustralia's network is essentially a distribution network rather than a transmission network, the ERAA notes that the application of service standards to EnergyAustralia may vary from other TNSPs.

Both Ergon Energy and the ERAA believe that the EnergyAustralia's revenue cap should include an obligation on EnergyAustralia to adopt new service standards as they are developed in conjunction with an accompanying penalty/incentive regime.

The EMRF believes that the ACCC should examine EnergyAustralia's service performance incentive mechanism, consistent with that determined for TransGrid.

The customers' group believes that inappropriately timed outages on the transmission system could significantly affect energy prices in the various energy market nodes leading to increased risk faced by retailers (and consumers). Accordingly, effects of transmission outages on the wholesale electricity market should be taken into account in assessing the performance of EnergyAustralia.

The customers' group also believes that 1 per cent of allowed revenue at risk for under performances implies that 99 per cent of the TNSP's revenue is guaranteed regardless of the level of performance. They insist that the commercial financial incentive of placing just 1 per cent of revenue at risk is inadequate.

The customers' group identifies that in previous revenue cap decisions the ACCC has structured its performance incentive scheme to achieve 'revenue neutrality'. Consumers, however, expect that with consistently increasing capex and opex, TNSP's performance would generally be improving. They believe that 'stretch factors' need to be applied to ensure that consumers are not simply paying an incentive bonus for the better performance that the increased investments would bring.

There is also a concern by the customers' group that, because TNSPs are regulated by a revenue cap, if a consumer reduces electricity consumption then other consumers will have to pay more transmission charges to 'compensate' for the reduced revenue. Therefore, even if EnergyAustralia's performance falls and leads to a lower demand, its revenue is assured with the transmission charges rising to compensate for the losses in volumes. This provides very little incentive for EnergyAustralia to produce a quality product to retain consumers and maintain volume.

8.5 ACCC's considerations

The ACCC has considered the information put forward by interested parties, GHD and EnergyAustralia.

The ACCC's service standard scheme was based on the premise that the TNSPs should be rewarded for increased service levels resulting from operational efficiencies.

The ACCC notes the arguments by interested parties that EnergyAustralia's revenue cap should include an obligation on EnergyAustralia to adopt new service standards as they are developed in conjunction with an accompanying penalty/reward regime. However, to do this would involve re-opening the revenue cap which is only allowed in certain circumstances under the code.

EnergyAustralia requested that the maximum impact of any single event be capped at seven days to reduce the distortions that may become apparent if an extended outage of a single circuit occurs.

The ACCC assumes that EnergyAustralia reported their transmission feeder availability data in accordance with the service standards guidelines, therefore the maximum impact of any single event was capped at 14 days. For the purpose of the 2004-2009 regulatory period, the ACCC requests EnergyAustralia to continue to cap their events at 14 days.

8.6 Conclusions

In order to set financial incentives, the ACCC intends to implement GHD's proposed performance measures and targets for EnergyAustralia. For the 2004-2009 regulatory period, the ACCC's draft decision is to adopt the weightings and targets recommended by GHD in Table 8.3.

Therefore, for the 2004-2009 regulatory period, EnergyAustralia has a financial incentive applying to its performance as measured by transmission circuit availability. However, EnergyAustralia is required to also measure their transmission circuit availability with the inclusion of:

- transformers and reactive plant, in accordance with the proposed standard definition
- significant lengths of new 132kV lines and other equipment, resulting from the re-classification of some assets from distribution to transmission during the 1999-2004 regulatory period.

In addition to this, the ACCC requires EnergyAustralia to report on the other performance measures contained in its service standards guidelines. This reporting requirement excludes the need to report on inter-regional constraints because EnergyAustralia does not own or operate any inter-regional assets.

Appendix A. Pass through rules

1 REGULATED PASS THROUGH

1.1 Rules form part of revenue cap

These Pass Through Rules form part of the revenue cap set by the ACCC to apply to EnergyAustralia for the regulatory control period commencing on 1 July 2004.

1.2 Entitlement to Pass Through

(1) If a Pass Through Event occurs, EnergyAustralia is entitled to amend the revenue cap to pass through the financial effect of the Pass Through Event in accordance with the procedures set out in these Pass Through Rules.

(2) Any Pass Through Amounts determined in accordance with these Pass Through Rules forms part of the revenue cap.

1.3 Form of Pass Through Amount

A Pass Through Amount may be expressed in any form which reasonably reflects the factors in clause 2.3 including:

(1) as a dollar increase or decrease in the amount of the allowed revenue cap for the relevant year or years (with EnergyAustralia to determine the corresponding change in customer charges in accordance with the National Electricity Code)

(2) as a percentage change in one or more customer charges or

(3) as a change to one or more customers charges.

2 PROCEDURE

2.1 Pass Through Event Statement

If EnergyAustralia believes it is or will be entitled to pass through the financial effect of a Pass Through Event, then it may give a Pass Through Event Statement to the ACCC specifying:

(1) details of the relevant Pass Through Event including the date on or from which the relevant Pass Through Event took effect or will take effect

(2) the estimated financial effects of the Pass Through Event on the provision of revenue capped transmission services including any documentary evidence that is reasonably available that substantiates the claimed financial effects of the Pass Through Event

(3) the Pass Through Amount proposed by EnergyAustralia in respect of the relevant Pass Through Event and the proposed form of the Pass Through Amount and

(4) the date from, and period over which, EnergyAustralia proposes that the Pass Through Amount may be applied.

2.2 ACCC's Decision

(1) Upon receipt of a Pass Through Event Statement, the ACCC must determine whether the Pass Through Event specified in the Pass Through Event Statement did occur or will occur and, if the ACCC decides that the Pass Through Event did occur (or will occur), the ACCC must decide:

(a) the Pass Through Amount in respect of the relevant Pass Through Event

(b) the form of the Pass Through Amount

(c) the date from, and period over which, the Pass Through Amount may be applied

and notify EnergyAustralia in writing of the ACCC's decision.

(2) The ACCC must give a notice under clause 2.2(1) within 40 Business Days of receiving a Pass Through Event Statement. The ACCC may, at its discretion, extend this period:

(a) on more than one occasion

(b) for an aggregate period of up to 40 Business Days and

(c) by giving written notice to EnergyAustralia, prior to expiry of the previous period, specifying the period of the extension.

(3) If the ACCC does not give a notice to EnergyAustralia under clause 2.2(1) within 40 Business Days (or such extended period as is notified pursuant to clause 2.2(2), of receiving the relevant Pass Through Event Statement, then the ACCC is taken to have notified EnergyAustralia of its decision that:

(a) the relevant Pass Through Event has occurred (or will occur) and

(b) the Pass Through Amount and the manner in which the Pass Through Amount is to apply are as proposed by EnergyAustralia in the Pass Through Statement.

2.3 Relevant Factors

In making a decision under clause 2.2, the ACCC must seek to ensure that the financial effect on EnergyAustralia associated with the relevant Pass Through Event is economically neutral taking into account the following factors:

(1) the materiality of the requested Pass Through Amount relative to allowed revenue

(2) the prudence of EnergyAustralia's decisions and actions (i.e. whether EnergyAustralia has through any imprudent act or omission, caused or aggravated the Pass Through Event)

(3) the time cost of money for the period over which the Pass Through Amount is to be applied

(4) in relation to a Change in Taxes Event:

(a) the amount of any increase or reduction in another tax, rate, duty, charge, levy or other like or analogous impost intended to offset in whole or in part the relevant Change in Tax Event and the manner in which and the period over which that increase or reduction occurs

(b) the amount included in the operating expenses or other cost inputs or parameters of EnergyAustralia's revenue cap

(5) in relation to a Terrorism Event, any loss, damage, cost or expense of any nature directly or indirectly caused by, resulting from or in connection with:

(a) the Terrorism Event

(b) any action taken in controlling, preventing, suppressing or in any way relating to the Terrorism Event

(6) in relation to an Insurance Event, the amount of any loss, damage, cost or expense of any nature directly or indirectly caused by, resulting from or in connection with the Insurance Event and

(7) in relation to a Service Standards Event, the financial effect on EnergyAustralia associated with any increased or decreased costs or risks (including in the nature, scope or asymmetry of risks) resulting from the Service Standards Event.

2.4 Application of Pass Through Amount

If EnergyAustralia has:

(1) received or is taken to have received a notice under clause 2.2 allowing EnergyAustralia to pass through a Pass Through Amount

(2) notified its affected customers of:

(a) the Pass Through Amount and

(b) the form in, date from and period over which EnergyAustralia will apply the Pass Through Amount

EnergyAustralia may apply the Pass Through Amount in the form, from the date of and over the period specified or taken to be specified in the notice from the ACCC.

3 DEFINITIONS & INTERPRETATION

3.1 Definitions

ACCC means the Australian Competition and Consumer Commission.

Applicable Law means any legislation, delegated legislation (including regulations), codes, licences or guidelines relating to the provision of a revenue capped transmission service and includes the National Electricity Code and the National Electricity Law.

Business Day means a day that is not a Saturday, Sunday or public holiday in New South Wales.

Authority means any government or regulatory department, body, instrumentality, minister, agency or other authority or any body which is the successor to the administrative responsibility to that department, body, instrumentality, minister agency or authority and includes the Independent Pricing and Regulatory Tribunal (IPART), National Electricity Market Management Company (NEMMCO), National Electricity Code Administrator (NECA) and the ACCC.

Change in Taxes Event means:

(1) a change in the way or rate at which a Relevant Tax is calculated (including a change in the application or official interpretation of a Relevant Tax) or

(2) the removal of a relevant tax or imposition of a new Relevant Tax

to the extent that the change, removal or imposition:

(3) occurs after the date of the Decision and

(4) results in a material change in the amount EnergyAustralia is required to pay or is taken to pay (whether directly, under any contract or as part of the operation expenses or other cost inputs or parameters of EnergyAustralia's revenue cap) by way of Relevant Taxes.

Decision means the decision of the ACCC setting out the revenue cap for EnergyAustralia's transmission business in relation to the regulatory control period commencing on 1 July 2004.

Insurance means insurance whether under a policy or a cover note or other similar arrangement:

(1) for risks of the sort for which EnergyAustralia was covered at the date of the Decision

(2) for amounts not less than amounts underwritten in favour of EnergyAustralia at the date of the Decision and

(3) on terms, including terms specifying deductibles payable and any applicable exclusions, no less favourable than the terms in place at the date of the Decision.

Insurance Event means where one or more of the following circumstances occurs (but only if EnergyAustralia is able to demonstrate that it took all reasonable precautions and was in no way negligent):

(1) where Insurance in respect of any risk becomes unavailable to EnergyAustralia

(2) where Insurance in respect of any risk becomes unavailable to EnergyAustralia at reasonable commercial rates

(3) where Insurance in respect of any risk becomes unavailable to EnergyAustralia on terms which are at least favourable to EnergyAustralia as those generally available at the date of the Decision

(4) where the cost of Insurance (including premiums and deductibles) in respect of any risk becomes materially lower or higher than the cost of Insurance at the date of the Decision

(5) EnergyAustralia has provided the ACCC with a copy of insurance premium invoices at least 50 business days before the start of the financial year, regardless of if a pass through event has occurred

(6) where an insurance benefit payment to EnergyAustralia under its insurance for risk of bushfire liability, is reduced by a deductible amount.

Pass Through Amount means a variation to EnergyAustralia's revenue cap as a result of a Pass Through Event determined in accordance with these Pass Through Rules. A Pass Through Amount may be positive or negative.

Pass Through Event means:

(1) a Change in Taxes Event

(2) a Terrorism Event

(3) an Insurance Event or

(4) a Service Standards Event.

Pass Through Event Statement means a notice in writing made by EnergyAustralia in accordance with clause 2.1.

Relevant Tax means any tax, rate, duty, charge, levy or other like or analogous impost that is:

(1) paid, to be paid, or taken to be paid by EnergyAustralia in connection with the provisions of transmission services or

(2) included in the operating expenses or other cost inputs or parameters of EnergyAustralia’s revenue cap

but excludes:

(3) penalties and interest for late payment relating to any tax, rate, duty, charge, levy or other like or analogous impost

(4) fees and charges paid or payable in respect of a Service Standards Event

(5) income tax (or state equivalent income tax) and capital gains tax

(6) stamp duty, financial institutions duty, bank accounts debits tax or similar taxes or duties and

(7) Any tax, rate, duty, charge, levy or other like or analogous impost which replaces the taxes and charges referred to in (3) to (6**)**.

Service Standards Event means a decision made by the ACCC, IPART or any other Authority or any introduction of, or amendments to, an Applicable Law after the date of the Decision that:

(1) has the effect of:

  (a) imposing or varying minimum standards (including safety or technical standards) on EnergyAustralia relating to revenue capped transmission services that are different than the minimum standards applicable to EnergyAustralia in respect of revenue capped transmission services at the date of the Decision

  (b) altering the nature or scope of services that comprise the revenue capped transmission services

  (c) substantially varying the manner in which EnergyAustralia is required to undertake any activity forming part of revenue capped transmission services from the date of the Decision or

  (d) increasing or decreasing EnergyAustralia’s risk in providing the revenue capped transmission services or

(2) results in EnergyAustralia incurring (or being likely to incur) materially lower or higher costs in providing revenue capped transmission services than it would have incurred but for that event.

Terrorism Event means an act, including the use of force or violence and/or the threat thereof, of any person or group of persons, whether acting alone or on behalf of in connection with any organisation or government, from which its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons, including the intention to influence or intimidate any government and/or put the public or any section of the public in fear.

3.2 Interpretation

In these Rules, unless the contrary intention appears:

(1) a reference to:

(a) a document, including these Rules, includes any variation or replacement of it

(b) a particular person includes a reference to the person's successors, substitutes (including person taking by novation) and assigns

(c) the word "person" includes an individual, a firm, a body corporate, a partnership, joint venture, syndicate, an unincorporated association, or any Authority

(d) a statute, ordinance, code or other law includes regulations and other instruments under it and consolidations, amendments, re-enactments or replacements of any of them

(e) a clause, annexure or schedule is a reference to a clause in or annexure or schedule to these Rules

(2) headings are for ease of reference only and do not affect the meaning of these Rules

(3) the singular includes the plural and vice versa and

(4) "including" and similar expressions are not and must not be treated as words of limitation.

Appendix B. Financial indicators

B.1 Code requirement

The code requires that the ACCC consider various issues when setting a revenue cap for a TNSP. One requirement when considering the TNSP's revenue requirement is 'any other financial indicators' as prescribed by clause 6.2.4(c)(9) of the code.

> 6.2.4 (c) In setting a *revenue cap* to be applied to each *Transmission network Owner* and/or *Transmission Network Service Provider* (as appropriate) in accordance with clause 6.2.4(b), the *ACCC* must take into account the revenue requirements of each *Transmission Network Owner* and/or *Transmission Network Service Provider* (as appropriate) during the *regulatory control period,* having regard for:
>
> …
>
> any other financial indicators.

B.2 Previous financial indicator analysis

In previous revenue cap decisions the ACCC has calculated and analysed various financial indicators. The purpose of this analysis was to predict the impact of the allowed revenue on the TNSP's ability to obtain credit. Consistent with the previous revenue caps, Table B.1 provides the same financial indicators based on EnergyAustralia's AR.

Table B.1 assumes a business profile of above average and excellent[61], which results in a credit rating of about 'A'. Hence the ACCC considers that its revenue cap for EnergyAustralia will not adversely affect either the ongoing financial viability or EnergyAustralia's ability to access capital markets.

The estimated credit ratings are set on the basis of the Standard's and Poor's ratings shown in Table B.3. The individual financial ratios have been calculated using the formulae in Table B.2.

The ACCC is satisfied that, by setting an appropriate WACC, it has already addressed EnergyAustralia's ability to obtain credit. In determining EnergyAustralia's WACC, the ACCC benchmark EnergyAustralia's gearing at 60 per cent and sets the debt margin based on a benchmark credit rating of 'A'.

The ACCC considers that EnergyAustralia's credit rating is likely to be above that suggested in Table B.1 because of the stability of its earnings and the lack of

[61] The ACCC considers EnergyAustralia's business profile lies between excellent and above average, given the likely stability of its earnings and the lack of competitors for its services.

competitors for its services. In fact, Standard and Poor's provide EnergyAustralia with a long term credit rating of 'AA'.[62]

Table B.1 Financial indicators

	2004/05	2005/06	2006/07	2007/08	2008/09
EBIT to Revenues (%)	75.19	76.06	75.92	76.02	76.14
EBITD to Revenues (%)	86.80	88.08	88.75	89.27	89.80
EBIT to Funds Employed (%)	10.92	11.05	11.19	11.25	11.45
EBIT to regulated assets (%)	10.92	11.05	11.19	11.25	11.45
Pre-tax interest cover (times)	2.69	2.72	2.76	2.77	2.82
Funds Flow Net Interest Cover (times)	3.11	3.15	3.23	3.26	3.33
S&P Rating Above average business profile	A	A	A	A	A
S&P Rating Excellent business profile	A	A	A	AA	AA
Funds Flow Net Debt Pay Back (years)	7.99	7.91	7.68	7.59	7.37
S&P Rating Above average business profile	BBB	BBB	BBB	BBB	BBB
S&P Rating Excellent business profile	A	A	A	A	A
Internal Financing Ratio (%)	56.42	71.44	61.04	75.90	101.38
S&P Rating Above average business profile	BBB	A	BBB	A	AAA
S&P Rating Excellent business profile	BBB	AA	A	AA	AAA
Gearing	0.60	0.60	0.60	0.60	0.60
Payout Ratio	61.09	61.09	61.09	61.09	61.09

Table B.2 Financial ratio formulae

EBIT/funds employed	Earnings Before Interest and Tax/(debt + equity)
Dividend payout ratio	Dividends/Net Profit After Tax (NPAT)
Funds flow interest cover	(NPAT + depreciation + interest + tax)/interest
Funds flow net debt pay back	(Debt - (investments + cash))/(NPAT + depreciation)
Internal financing ratio	(NPAT + depreciation - dividends)/capex
Pre-tax interest cover	EBIT/interest
Gearing	Debt/(debt + equity)

[62] Standard and Poor's *Australian Report Card Utilities*, March 2004.

Table B.3 Standard and Poor's key indicators

Utility business profile	Funds flow interest cover (times)				Funds flow net debt payback (years)				Internal financing ratio (per cent)			
	AAA	AA	A	BBB	AAA	AA	A	BBB	AAA	AA	A	BBB
Excellent	4.00	3.25	2.75	1.50	4.0	6.0	9.0	12.0	100	70	60	40
Above average	4.25	3.50	3.00	2.00	3.5	5.0	7.0	9.0	100	80	70	50
Average	5.00	4.00	3.25	2.50	3.0	4.0	5.5	7.0	100	100	90	55
Below average	-	4.25	3.50	3.00	-	4.0	5.5	7.0	-	100	100	75
Vulnerable	-	-	4.00	3.50	-	-	4.0	6.0	-	-	100+	90

Note:

AAA Extremely strong capacity to meet financial commitments.

AA Very strong capacity to meet financial commitments.

A Strong capacity to meet financial commitments but somewhat susceptible to adverse economic conditions and changes in circumstances.

BBB Adequate capacity to meet financial commitments but more susceptible to adverse economic conditions however is not considered vulnerable.

Ratings in the BB, B, CCC, CC and C categories are regarded as having significant speculative business, financial and economic conditions.

Appendix C. Calculating the financial incentive

EnergyAustralia has only one performance measure linked to a financial incentive under this revenue cap. Hence the performance under this measure equals the total ‘S’ as described in section 7.2. These equations are shown graphically in figure C.1.

Table C.1 Equations to calculate ‘S’

Transmission feeder availability											
S_1	=	Gradient	x	Availability	+	Intercept	Where:				
S_1	=	0.0100							Availability	>	96.7
S_1	=	0.0167	x	Availability	-	1.60167	96.1	<	Availability	≤	96.7
S_1	=	0.0000					96.1	≤	Availability	≤	96.1
S_1	=	0.0125	x	Availability	-	1.20125	95.3	≤	Availability	<	96.1
S_1	=	-0.0100							Availability	<	95.3

Figure C.1 Financial incentive curve