NSW Electricity Distribution Pricing 2004/05 to 2008/09

Final Report

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

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Final Report

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FOREWORD

The Tribunal has issued this distribution pricing determination and report under the National Electricity Code. This is the second determination it has made under the Code. As from 1 July 2004, a new form of regulation—a weighted average price cap—will apply to the four NSW distribution network services providers (DNSPs).

In recent years, electricity consumers in NSW have seen average electricity network prices fall in real terms. At the same time, they have increased their demand for electricity and, hence, their use of distribution networks. Peak demand has risen even more sharply, placing a strain on the existing distribution infrastructure. The response of the DNSPs has been to increase growth-related capital expenditure, with little use of demand management alternatives to network investment.

Increasing demand has put greater pressure on distribution networks, requiring greater capital and maintenance spending. In addition, greater capital and maintenance expenditures has also been required by the increasing average age of the assets. The Tribunal has had little option but to allow for increased revenues and, therefore, prices over the next regulatory period. All four DNSPs requested substantial increases in average distribution prices over the next regulatory period. This is underpinned by proposed total capital and operating expenditure of $8 billion dollars over five years, proposed adjustments to their opening asset values, and proposed rates of return on assets that are at the high end of the range.

After careful analysis of these proposals and having regard to the requirements of the Code, the Tribunal has found that most of the proposed expenditure is justified, but that adjustments to the opening asset values and the proposed higher rates of return are not. This decision allows modest increases in the distribution component of electricity bills. These increases will translate into small increases in customers' final electricity bills, as distribution charges form about one third of these bills.

As indicated in the final report of its Inquiry into the Role of Demand Management, the Tribunal strongly believes that there is untapped potential for efficient and commercially viable demand management in NSW. Through this determination, it has removed the regulatory barriers to its increased use. DNSPs should be working to overcome the cultural and other barriers within their own organisations to fully explore the use of demand management options to better manage increasing capital spending and improve asset utilisation.

Given the very large expenditures on the network by the DNSPs, the Tribunal is also concerned that these businesses deliver levels of service that are consistent with these expenditures. For this reason, this determination introduces a package of measures to address service quality. These measures include collection and publication of performance statistics, a 'paper trial' S-factor, focusing on reliability and, subject to Ministerial approval, an expanded set of guaranteed customer service standards.

The Tribunal considers that this determination balances the interests of all key stakeholders. Consumers are protected from significant price shocks. DNSPs will be able to make sufficient investment in their networks to continue to deliver a safe and reliable supply to their customers. They will also be able to provide a commercial return to their owner on funds invested in their business.

This determination applies from 1 July 2004 to 30 June 2009.

James Cox
Acting Chairman
June 2004

1 INTRODUCTION

The Independent Pricing and Regulatory Tribunal of New South Wales (the Tribunal) is the Jurisdictional Regulator for prices charged by the NSW's four Distribution Network Service Providers (DNSPs)—EnergyAustralia, Integral Energy, Country Energy and Australian Inland. It regulates these prices under the National Electricity Code (the Code), in accordance with the objectives and principles set out in the Code.

The Tribunal's 1999 determination on distribution service prices will expire on 30 June 2004. For the next regulatory period—1 July 2004 to 30 June 2009—new regulatory arrangements will apply. This report explains the Tribunal's determination for this period, and outlines the new arrangements. The determination itself is provided as a separate document.[1]

1.1 Need for price increases

Over the past seven years, average electricity network prices have reduced in real terms by 24 per cent, while average demand or energy consumption has risen by 31 per cent. Peak demand has risen even more sharply, placing strain on the existing infrastructure. DNSPs have responded by increasing their growth-related capital expenditure programs, with little focus on demand management options. This has resulted in lower asset utilisation.[2] In some cases, growth-related expenditure has been at the expense of replacement or refurbishment expenditures, which has placed even greater strain on the existing infrastructure.

The trend of increasing consumption and reducing prices is no longer sustainable. For the coming regulatory period, all four DNSPs requested substantial increases in average distribution prices. Their proposed increases were driven by a proposed total expenditure program of around $8 billion dollars over five years, proposed adjustments to their opening asset values, and proposed rates of return on assets that are at the high end of the range. These proposals suggest they plan to make limited use of demand management to moderate the need for growth-related expenditure.

1.2 Overview of determination

The Tribunal examined the DNSPs' proposals in detail. It accepts the view of its total cost consultant that the DNSPs' total expenditures in the past regulatory period (1999 to 2003) were prudent, and that their proposed capital expenditure programs are generally efficient, (although there is scope for small reductions in the capital expenditure programs of EnergyAustralia and Integral Energy). But it does not accept that the DNSPs' proposed adjustments to their opening asset values are justified, nor that their proposed rates of return are appropriate. Even so, the DNSP's revenue requirements are significantly higher than in the last regulatory period. This means real increases in the distribution component of electricity bills are necessary.

The Tribunal also considered carefully how these increases should be spread over the regulatory period. All four DNSPs proposed a larger increase in distribution prices in 2004/05 (a P-nought adjustment) followed by smaller increases in the following years.

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1 IPART, *Determination NSW Electricity Pricing 2004/05-2008/09*, June 2004.

2 Asset utilisation relates to use of network over all time periods not just at the time of peak demand.

In the 1999 determination, the Tribunal chose to use a revenue glide path approach,[3] so price changes (and therefore the DNSPs' revenue changes) would be spread more evenly over the regulatory period. For EnergyAustralia and Integral Energy, this approach resulted in them being projected to collect a higher amount of revenue than their projected total costs provided for in the determination.[4] For Country Energy and Australian Inland, it resulted in them being projected to collect a lower amount of revenue than their projected total costs.

The Tribunal recognises the impact of the glide path approach on revenue recovery levels. However, it believes that this approach provides appropriate incentives for DNSPs[5]. For example, continuing to use this approach in the face of cost increases signals to DNSPs that the Tribunal is committed to symmetrical treatment of efficiency carryover, whereby both cost reductions and cost increases are carried across regulatory periods via the glide path mechanism.

For the 2004-09 determination, the Tribunal has decided to use a hybrid of the P-nought and glide path approaches. This hybrid approach provides the same incentives as the glide path, but to a lesser degree. Thus, it provides a reasonable balance between incentives and price impacts on one hand, and the level of cost recovery on the other hand. In addition, it allows the Tribunal to more easily manage competing outcomes in the overall determination. These outcomes include the financial risks facing the DNSPs and the need to ensure that they earn adequate revenue for expenditures necessary to maintain their service standards.

The Tribunal's decision on the average allowable increases in distribution prices for the 2004-2009 regulatory period is shown in Table 1.1. These increases are substantial, but significantly less than proposed by the DNSPs.

Table 1.1 Final decision on distribution prices compared with DNSP proposals

	Standardised DNSP's proposals[1]		Final decision	
	DNSP's proposed annual price increase – distribution	**NPV of costs not recovered**	**Annual distribution price increase**	**NPV of costs not recovered**
EnergyAustralia	CPI + 19.4% in 2004/05 then CPI + 1%	0	CPI + 7% in 2004/05 then CPI+1.6%	$50m
Integral Energy	CPI + 11.1% in 2004/05 then CPI + 1%	0	CPI + 5% in 2004/05 then CPI +1.5%	$22m
Country Energy	CPI + 13.2% in 2004/05 then CPI plus 5.7%	$233m	CPI + 7% in 2004/05 then CPI + 2.5%	$114m
Australian Inland	CPI + 15.6% in 2004/05 then CPI + 6.6%	$12m	CPI + 7% in 2004/05 then CPI + 2.5%	$14m

Note:

1 In developing their pricing proposals in April 2003 the DNSPs have used differing assumptions over a number of parameters. Table 1.1 presents each DNSP proposal based on a common assumption for inflation, and a common split between prescribed and excluded services.

3 This approach is also known as the straight line smoothing option.

4 However, their actual operating and capital expenditures turned out to be well in excess of those allowed for the 1999 determination.

5 The glide path approach ensures that incentive power is maintained throughout the regulatory period.

For customers, these decisions mean that distribution prices across NSW will increase in real terms by a total of 14 per cent over the next five years, or approximately 2.7 per cent per annum. The forecast average cumulative real distribution price increases for each DNSP (compared with 2003/04 prices) are shown in Table 1.2. However, these increases will translate into much smaller increases in customers' final electricity bills, as distribution charges form somewhere between 20 to 40 per cent of these bills, depending on which network and retail tariff the customer is on.

For example, in 2004/05 a typical residential customer living in Sydney[6] would see a nominal price increase in their final bill of between $50 to $60 a year (exclusive of GST), or about a $1 per week.[7] Similarly, a residential customer in regional NSW would see a nominal price increase in their final bill of around $50 to $70 a year, or about a $1.00 to $1.35 per week.[8]

Table 1.2 Real cumulative distribution price increases for the 5 years to FY2009

DNSP	Increase
EnergyAustralia	14. 0%
Integral Energy	11.4%
Country Energy	18.1%
Australian Inland	18.1%

1.3 New regulatory arrangements

The 2004-09 determination also sets out a 'package' of decisions that establishes how the Tribunal will regulate network tariffs (comprised of distribution use of system (DUOS) tariffs and 'transmission cost recovery tariffs'), and other fees that DNSPs can charge for distribution services over the 2004-09 regulatory period. This package includes:

- a weighted average price cap for DUOS tariffs and miscellaneous and monopoly fees
- a D-factor in the price cap control formula that allows DNSPs to recover:
    - approved non-tariff-based demand management implementation costs, up to a maximum value equivalent to the expected avoided distribution costs
    - approved tariff-based demand management implementation costs
    - approved revenue foregone as a result of non-tariff-based demand management activities
- exhaustive lists of maximum charges for miscellaneous services and mandatory charges for monopoly services
- a package of incentives for service quality, but no monetary S-factor
- a cost pass through mechanism for specified costs that DNSPs expect to incur but cannot quantify at this stage and a general cost pass through mechanism, allowing for the pass through of approved costs for:

6 A network customer of EnergyAustralia.

7 The retail bill has been increased by CPI plus 5% -the maximum increase for residential customer under the Tribunal's Retail Determination, June 2004. Prices are ex-GST.

8 The retail bill has been increased by CPI plus 5% -the maximum increase for residential customer under the Tribunal's Retail Determination, June 2004. Prices are ex-GST.

  - change in tax events
  - regulatory events.
- recovery of transmission-related payments (including TUOS charges paid to transmission network service providers, inter-distributor transfer payments and avoided TUOS charges)
- price limits for residential and non-residential network tariffs (excluding CRNP tariffs)
- pricing principles, public consultation and pricing information disclosure requirements
- a light-handed form of regulation for excluded distribution services.

1.4 Structure of report

This report explains the Tribunal's determination in detail, including why it reached its decisions and what those decisions mean for the DNSPs, customers and other stakeholders:

- Chapter 2 provides background information about the National Electricity Code and the Tribunal's public consultation process
- Chapter 3 provides a comprehensive overview of the regulatory framework that will apply from 1 July 2004, including the length of the regulatory period, the definition of prescribed distribution services, and the components of the regulatory package
- Chapters 4 to 7 discuss the Tribunal's methodology, analysis and decisions in setting the weighted average price cap for DUOS tariffs, and calculating the amount by which each DNSP's average prices can increase in each year over the regulatory period (that is, the X-factor in the price cap formula)
- The remaining chapters set out the Tribunal's decisions in relation to each of the other components of the regulatory package, and discuss its key considerations in making these decisions.

The Tribunal members who considered this determination were Mr James Cox (Acting Chairman), and Ms Cristina Cifuentes (Member).

2 BACKGROUND

The Tribunal has made this determination[9] under the National Electricity Code, which among other things, sets out the principles and objectives for the pricing of distribution network services. This chapter explains the requirements of the Code with respect to distribution pricing and the Tribunal's role in setting these prices. It also describes the process that the Tribunal followed in making its determination. Appendix 4 provides an overview of the NSW electricity industry and the DNSPs' operations.

2.1 The National Electricity Code

As Jurisdictional Regulator for NSW, the Tribunal is responsible for regulating distribution service prices in the state under the National Electricity Code. The Tribunal's specific functions include:

- formulating guidelines and rules to apply to distribution service pricing
- determining which distribution services should be deemed to be 'prescribed distribution services'
- determining the form of economic regulation for prescribed distribution services
- determining the length of the regulatory control period
- determining, if it chooses to depart from the pricing methodology in Chapter 6, Part E of the Code, the alternative pricing methodology that is to apply
- placing limits on the annual variation in published distribution service prices.

The Tribunal's determination is made pursuant with Chapter 6, Part D of the Code, which applies to network pricing arrangements and sets out the distribution service pricing regulatory regime. Clause 6.1.1 summarises the key principles and core objectives that are intended to apply to the network pricing arrangements that the Tribunal administers. Clause 6.10.2 requires that the regime administered under Part D of the Code seek to achieve specified outcomes. Clause 6.10.3 requires that the regime be administered in accordance with stated principles. These provisions are reproduced in full in Appendix 3.

In addition, the Tribunal has had regard to the specific matters that the Code requires it to take into account in exercising specific functions. (For example, Clause 6.10.5 stipulates the matters it should have regard to in setting the regulatory cap.)

The Tribunal does not regulate transmission prices. The Australian Competition and Consumer Commission has responsibility for regulating transmission companies in Australia. However, transmission charges are passed through by the DNSPs to retailers and on to customers and the Tribunal's regulatory framework needs to accommodate this pass-through. The ACCC released its draft determination on transmission revenues for TransGrid and EnergyAustralia for the 5-year regulatory period from 2004/05 on 4 May 2004. The ACCC's final determination is due in April 2005.

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9 IPART, *NSW Electricity Distribution Pricing 2004/05-2008/09 Determination*, June 2004. This has been published as a separate document.

2.2 Process undertaken for this review

As part of the process leading to the final determination, the Tribunal undertook an extensive public consultation process and analysis to determine the detail of the regulatory arrangements for the period starting 1 July 2004.

Figure 2.1 describes the key steps in the review process. The Tribunal effectively began this review in 2001, when it considered the economic regulatory arrangements to apply to NSW DNSPs. Since then it has:

- undertaken a process to determine the appropriate classification of activities in prescribed and excluded services, which affects how these activities would be regulated[10]
- produced an issues paper, draft financial models and information requests to assist DNSPs in preparing their submissions to the review
- produced a draft determination and supporting report for public comments
- taken account of views on the draft determination and conducted supplementary analysis to finalise the determination.

The specific activities the Tribunal has taken as part of its public consultation process are detailed below, including releasing documents for public comment and holding public forums to discuss key issues.

2.2.1 Consultation documents

The Tribunal has released the following documents for public comment as part of the review process. Appendix 1 lists all public submissions received by the Tribunal.

Discussion/issues papers

- Discussion paper on form of regulation, *Form of Economic Regulation for NSW Electricity Charges*, August 2001.
- Discussion paper on defining prescribed distribution services, *Review of Prescribed Distribution Services*, June 2002.
- Industry-wide paper on the weighted average cost of capital, *Weighted Average Cost of Capital,* August 2002.
- Issues paper, *Regulatory Arrangements for the NSW Distribution Network Service Providers from 1 July 2004, Issues Paper*, November 2002.
- Draft financial models and explanatory notes, November 2002.
- Terms of reference for its total cost review (capital and operating expenditure), October 2002.

10 The Tribunal's final decision on prescribed and excluded services is part of this final determination.

Figure 2.1 The process undertaken for this review

KEY INPUTS	▪ National Electricity Code ▪ Tribunal's own analysis ▪ Public submissions on discussion paper, public forum and Draft Notice	▪ National Electricity Code ▪ Tribunal's own analysis ▪ Public submissions on discussion paper, public forum and Draft Notice	▪ National Electricity Code ▪ Tribunal's own analysis ▪ Public submissions on draft financial models and informative requests	▪ National Electricity Code ▪ Tribunal's own analysis ▪ Consultant report on Total Cost review. ▪ Other commissioned consultants reports. ▪ Public submissions on various consultation papers. ▪ Completed information requests and draft financial models.	▪ National Electricity Code ▪ Tribunal's own analysis ▪ Public submissions on Tribunal's draft decision. ▪ Consultant's report on review of DNSPs' revised costs. ▪ Consultant's report on EnergyAustralia's revised asset lives.
STEPS	**Step 1: Determining the form of regulation** ▪ Issued discussion paper on form of regulation. ▪ Held public forum on form of regulation. ▪ Reviewed submissions on discussion paper and public forum. ▪ Released Draft Notice of form of regulation and received submissions. ▪ Release Final Notice of form of regulation.	**Step 2: Determining prescribed and excluded distribution services** ▪ Released discussion paper on defining prescribed distribution services. ▪ Received public submissions and discussion papers. ▪ Released draft decision on prescribed and excluded services.	**Step 3: Developing Issues Paper and information requests** ▪ Released an industry-wide discussion paper on weighted average cost of capital. ▪ Developed draft financial models and explanatory notes. ▪ Released Issues Paper for review. ▪ Released financial information requests for completion by DNSPs.	**Step 4: Development of Draft Determination** ▪ Commissioned review of DNSPs' proposed costs. ▪ Reviewed public submissions. ▪ Commissioned special-ised technical advice. ▪ Public forums on sub-missions, pricing issues, service quality incentives, and total cost review. ▪ Released discussion papers on inclining block tariffs, service quality, growth forecasts, and preliminary analysis. ▪ Released Tribunal's Draft Determination and Report. ▪ Released draft decision on demand management.	**Step 5: Finalising the Determination** ▪ Reviewed public submissions on Draft Determination. ▪ Commissioned review of DNSPs' revised operating and capital expenditures. ▪ Commissioned review of EnergyAustralia's revised asset lives. ▪ Released Tribunal's Final Determination.

- Issues paper, *Providing Incentives for Service Quality in NSW Electricity Distribution*, May 2003.
- Secretariat discussion paper on inclining block tariffs, *Inclining Block Tariffs for Electricity Network Services*, July 2003.
- Discussion paper on the DNSPs growth forecasts, *Determining sales volumes for the 2004 electricity network review*, July 2003.
- Secretariat Discussion Paper, *2004 Electricity Distribution Review - Preliminary Analysis,* September 2003.

Consultants' reports[11]

- Allen Consulting, *The Incorporation of Service Quality in the Regulation of Utility Prices,* March 2001.
- PB Associates, *Review of NSW Distribution Network Service Provider's Measurement and Reporting of Network Reliability,* July 2003.
- Allen Consulting, *Principles for determining regulatory depreciation allowances*, September 2003.
- Meritec Limited (New Zealand), *Review of Capital and Operating Expenditure of the NSW Electricity Distribution Network Service Providers – Final Report*, September 2003.
- SKM/M-Co, *Reducing Regulatory Barriers to Demand Management – Avoided Distribution Costs and Congestion Pricing for Distribution Networks in NSW,* December 2003.
- PB Associates, *Providing Incentives for Service Quality - Incentive Rates for S-Factors*, May 2004.
- McLennan Magasanik Associates, *Review of demand forecasts for the 2004 electricity network review*, April 2004.
- Wilson Cook, *Review of Revised Operating and Capital Expenditures of DNSPs*, May 2004.[12]
- Burns and Roe Worley, *Review of EnergyAustralia's Asset Lives*, May 2004.

Draft decisions/notices

- Draft Notice Under Clause 6.10.3 of the Code, *Economic Regulatory Arrangements*, May 2002.
- Notice Under Clause 6.10.3 of the Code, *Economic Regulatory Arrangements*, June 2002.
- Draft decision on prescribed and excluded distribution services, *Review of Prescribed and Excluded Distribution Services, Draft Decision*, February 2003.
- Tribunal's Draft Decision and Determination, *NSW Electricity Distribution Pricing 2004/05 to 2008/09 Draft Report* and, *NSW Electricity Distribution Pricing 2004/05 to 2008/09 Draft Decision*, January 2004.

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11 In most circumstances, the Tribunal also released draft versions of these reports for comment. Only the final reports are listed here.

12 The consultants used by Wilson Cook were previously with Meritec (New Zealand) and undertook the Total Cost Review.

- Draft Decision on demand management, *Treatment of Demand Management in the Regulatory Framework for Electricity Distribution Pricing 2004/05 to 2008/09,* Draft Decision, February 2004

The Tribunal also released its final decision on the form of regulation on 25 June 2002.[13]

2.2.2 Public forums

The Tribunal held public forums on the following topics:

- Form of regulation, 21 February 2002.
- Pricing issues through the Pricing Issues Consultation Group (Various meetings held through 2003 and 2004).
- DNSPs' initial submissions, 11 April 2003.
- Total Cost Review — Draft Report, 11 July 2003.
- Non-DNSPs' initial submissions, 17 July 2003.
- Service quality incentive mechanism, 29 July 2003.
- Key issues in draft determination, 18 and 30 March 2004.

13 IPART, *Final Notice Under Clause 6.10.3 of the Code, Economic Regulatory Arrangements*, 25 June 2002.

3 OVERVIEW OF REGULATORY ARRANGEMENTS

The Tribunal has established how it will regulate the network tariffs and other fees DNSPs can charge for prescribed distribution services over the 2004/05-2008/09 regulatory period. Network tariffs include distribution use of system (DUOS) tariffs and transmission cost recovery tariffs.[14] Other fees include charges for miscellaneous and monopoly services.

An overview of the new regulatory arrangements is provided below—including the length of the regulatory period, the services that are subject to these arrangements, and the key elements of the regulatory package.

3.1 Length of the regulatory period

The Tribunal has decided that the regulatory period will be five years, commencing 1 July 2004 and ending 30 June 2009.

The Code requires that the Tribunal apply its chosen form of economic regulation for a period of at least three years.[15] In deciding on a five-year regulatory period, the Tribunal considered the implications of the length of the regulatory period on the incentives for efficiency improvements, the predictability and stability of the regulatory environment, and the effectiveness of regulation. In general, a longer regulatory period provides:

- greater incentives for achieving increased efficiency, by allowing the DNSPs to retain more of any gains (in the form of higher profits) arising from cost reductions
- a more stable and predictable regulatory environment for the DNSPs, which may lower business risk and lead to better investment decisions
- fewer regulatory reviews and lower costs for stakeholders.

However, it can also have undesirable impacts, including:

- delaying the delivery of benefits from efficiency gains to consumers
- increasing the risk that industry and technological changes will create significant disparity between costs and revenues.

The Tribunal believes that a five-year regulatory period strikes a balance between providing incentives for improving efficiency, reducing regulatory uncertainty, and minimising the risk that changes in the industry will affect the appropriateness of the regulation. Other regulators in Australia appear to hold similar views. For example, the jurisdictional regulators for distribution businesses in Victoria and South Australia have adopted five-year regulatory periods, while the Queensland regulator has adopted a four-year period. The Australian Competition and Consumer Commission has adopted a five-year regulatory period for Transmission Network Service Providers.

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14 The Tribunal has called what is commonly known as TUOS tariffs, 'transmission cost recovery tariffs', which recover transmission (TUOS) charges paid to TNSPs, avoided TUOS payments and inter-distributor transfer payments to other DNSPs. DNSPs bill customers on the basis of the total network tariff, although customers will be able to access the DUOS and transmission cost recovery tariff split if required.

15 Clause 6.10.5 of the National Electricity Code.

In addition, all stakeholders who responded to the Tribunal's issues and analysis papers[16] for this review supported a five-year period.

3.2 Prescribed distribution services

The Tribunal has decided that prescribed distribution services will include all distribution services provided by the DNSP except for those listed by the Tribunal as excluded distribution services (see Table 3.1).

The Tribunal based its decisions about whether or not to include individual services in the list of excluded services primarily on the basis of whether they are contestable in NSW. Its analysis and rationale for these decisions and the separate, more 'light-handed' regulatory arrangements that will apply to excluded services are discussed in detail in Chapter 16.

Table 3.1 List of excluded distribution services

Customer funded connections	Design and construction of new connection assets; design and construction of customer-funded network augmentations
Customer-specific services	Services requested by the customer which includes; asset relocation works; conversion to aerial bundled cable; temporary, stand-by, reserve or duplicate supplies; and other non-standard customer-requested services. (However, recoverable work undertaken by DNSPs in emergency conditions and separately defined monopoly services are prescribed distribution services)
Metering services for types 1- 4 meters	Including meter supply; installation and maintenance; meter reading; meter tests
Public lighting – construction and maintenance	Construction and maintenance of street lighting assets

3.3 Regulatory arrangements for prescribed distribution services

The Tribunal has decided that the regulatory arrangements for prescribed distribution services include:

- **A weighted average price cap for DUOS tariffs and miscellaneous and monopoly fees.** This includes using a building block approach to determine each DNSP's notional revenue requirement, which is a key factor in the Tribunal's decision on the amount by which the DNSPs' average prices can change.
- **Recovery of DNSP transmission-related costs through transmission cost recovery tariffs.** This includes transmission charges DNSPs pay to TNSPs, avoided TUOS payments, and inter-distributor transfer payments.
- **Price limits on each residential and non-residential network tariff[17] and on charges for miscellaneous and monopoly services.**
- **DNSPs being responsible for setting network tariffs, subject to adherence to pricing principles and requirements for the disclosure of price information and public consultation.**

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16 IPART, *Regulatory arrangements for the NSW Distribution Network Service Providers from 1 July 2004 - Issues Paper*, November 2002 and IPART, *2004 Electricity Distribution Review - Preliminary Analysis Secretariat Discussion Paper*, September 2003.

17 Excluding customers on individually calculated prices.

- **A separate form of light-handed regulation for excluded distribution services.**

Each of these elements is discussed in detail below. Figure 3.1 illustrates the components of the building block approach the Tribunal used to determine the notional revenue requirement for each DNSP. Figure 3.2 illustrates the inter-relationship between the parts of the pricing framework.

Figure 3.1 The 'building block' approach to assessing notional revenue requirements for 2004-09

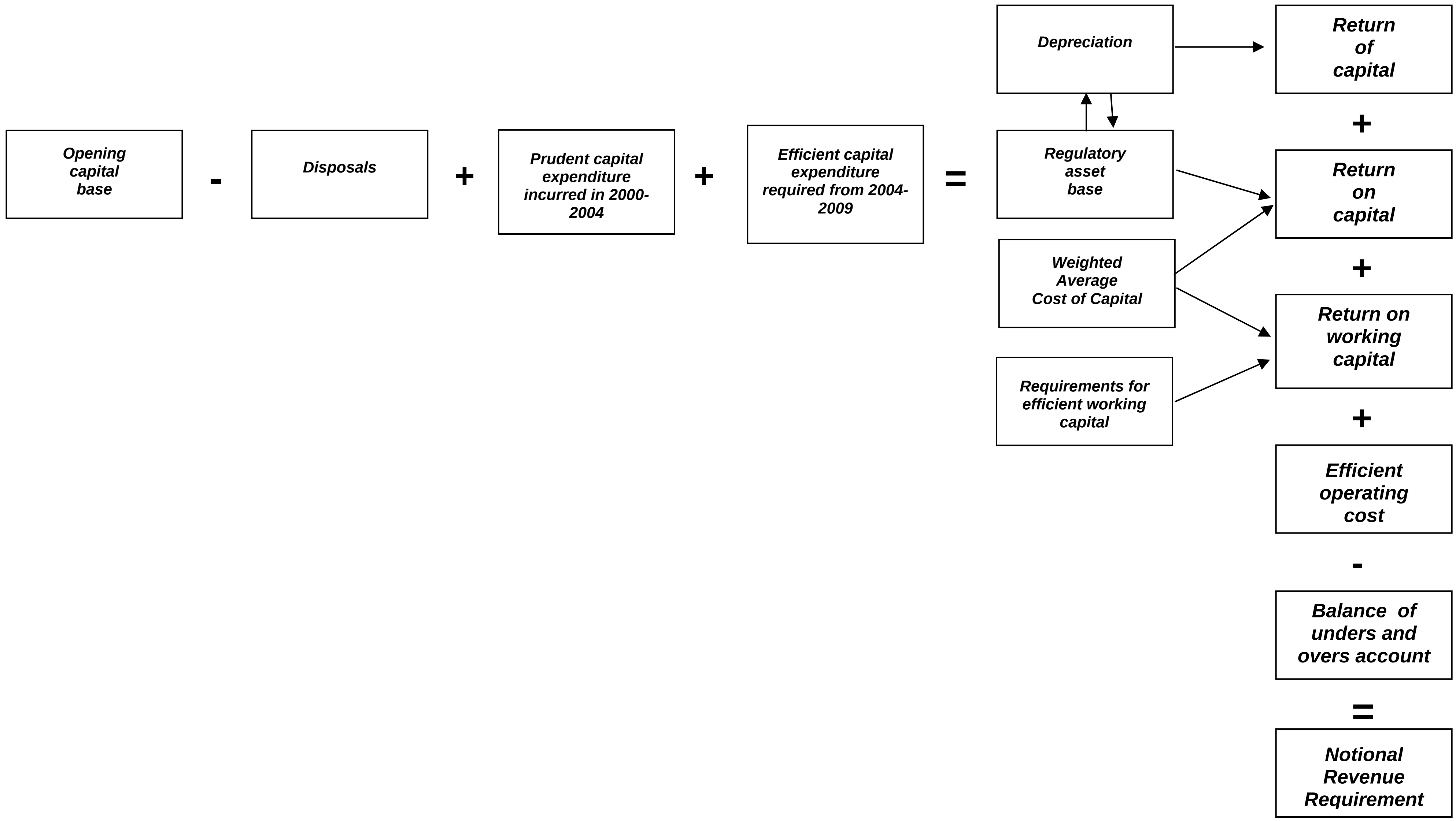
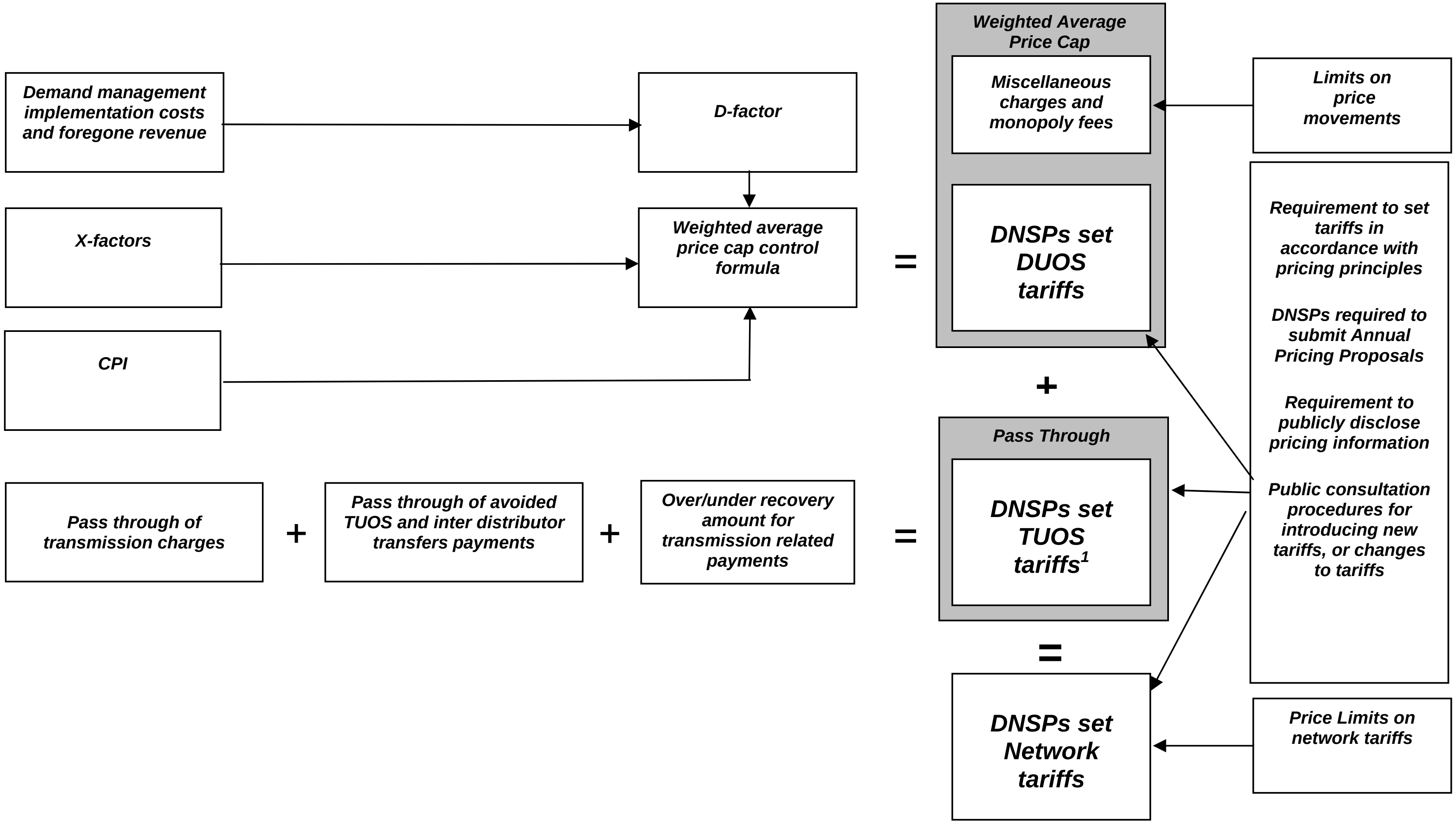


Figure 3.2 Regulatory arrangements from 1 July 2004 – 30 June 2009



[1] That is, Transmission Cost Recovery Tariffs.

3.3.1 The weighted average price cap for DUOS tariffs and miscellaneous charges and monopoly fees

DUOS tariffs, miscellaneous charges and monopoly fees will be regulated under a weighted average price cap. The weighted average price cap control formula will take the form, for Year *t+1*:[18]

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t+1} * q_{ij}^{t-1}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t} * q_{ij}^{t-1}} \leq 1 + \Delta CPI + X_{t+1} + D_{t+1} \qquad i=1,\ldots,n \text{ and } j=1,\ldots,m.$$

where:

the DNSP has *n* Relevant Prescribed Distribution Service Charges,[19] which each have up to *m* components:

p_{ij}^{t+1} is the proposed price for component *j* of the Relevant Prescribed Distribution Service Charge *i* for Year *t+1*

p_{ij}^{t} is the price charged by the DNSP for component *j* of the Relevant Prescribed Distribution Service Charge *i* in Year *t* (being the Year which immediately precedes Year *t+1*)

q_{ij}^{t-1} is the Audited Quantity of component *j* of the Relevant Prescribed Distribution Service Charge *i* that was charged by the DNSP in Year *t-1* (being the Year immediately preceding Year *t*)

D_{t+1} is demand management cost recovery factor for Year *t+1* calculated to recover certain approved demand management implementation costs and foregone revenue incurred in Year *t-1*

X_{t+1} is the allowed real change in average prices from Year *t* to Year *t+1* of the regulatory control period as determined by the Tribunal, as set out for that DNSP in Annexure 4 of the determination and discussed in chapter 7 of this report

ΔCPI is the change in the Consumer Price Index in the 12-month period from January of the Year *t-1* to December of the Year *t,* as compared with the preceding twelve month period (see below).

18 The Tribunal has expressed the weighted average price cap in the form CPI+X, rather than the more usual CPI-X. This reflects the fact that real price increases are expected in the coming regulatory period. A positive value of X indicates a real price increase.

19 As defined in the Tribunal's determination.

Prices and quantities

The weighted average price cap operates by restricting the (weighted) average change in the DNSPs' prices (DUOS tariffs, miscellaneous charges and monopoly fees, and charges for recoverable works for emergency services) to a limit determined by the constraint specified by the expression on the right hand side of the above equation. The prices are weighted by the corresponding quantities sold by the DNSP. In setting prices for the upcoming Year *t+1*, DNSPs must ensure that the average price change relative to the prices it is charging in the current Year *t* satisfy the constraint. For 2004/05, the prices for the 2003/04 are to be taken as those specified in Annexures 3 and 6 of the 2004-09 determination.

The quantities used to weight the DNSPs prices are the audited quantity data from the previous Year *t-1*. The use of quantity weights with a two-year lag is required as these are the most recent audited data available.

The treatment of prices and quantities for new tariffs, new tariff components and in the event of customer movement instructed by the DNSP, is discussed in the next section.

Use of 'reasonable estimates' in the weighted average price cap

Under the determination, the DNSPs will be required to provide 'reasonable estimates' as a substitute for the quantity q_{ij}^{t-1} factor for use in the weighted average price cap and price limits equations for:

- the introduction of new tariffs or new tariff components
- existing tariffs where customers are transferred by the DNSP to alternative, existing tariffs.

In the case of new tariffs or new tariff components,[20] there is no data relating to previous quantities sold (q_{ij}^{t-1}) available, hence the DNSP must provide an estimate of what the consumption would have been, based on the consumption profile of the customers they are moving to that tariff.

In the case of customer movement between tariffs during the regulatory period, the relationship between consumption, load profiles and tariffs assumed when setting the X-factor, is changed. Until the (q_{ij}^{t-1}) reflect this, revenue under the weighted average price cap will accrue at a different rate to what was assumed.[21] The DNSP must provide an estimate of what the quantity would have been, based on the consumption profile of the customers they are moving to that tariff. An adjustment to the historical volumes of the 'origin' tariff - that is, the tariff from where the customer originated from, will also be required.

The detail of this process and the assumptions the DNSP must make when setting the reasonable estimates is set out in Appendix 5.

[20] Including where a tariff component changes structure.

[21] Revenue from new customers, whether they move to an existing tariff or new tariff, has been taken into account in the X-factor calculation via a growth assumption.

Calculating the change in CPI (∆CPI)

The Tribunal has decided that the change in CPI (∆CPI) is the change in the Consumer Price Index, All Groups, Weighted Average of eight Capital Cities, over a 12-month period from January to December, compared with the preceding 12-month period.

The ∆CPI term in the weighted average price cap formula allows network charges to be indexed for inflation. The year-on-year change in CPI is calculated as:

$$\Delta CPI = \left(\frac{CPI_{Mar,\ t-1} + CPI_{June,\ t-1} + CPI_{Sept,\ t} + CPI_{Dec,\ t}}{CPI_{Mar,\ t-2} + CPI_{June,\ t-2} + CPI_{Sept,\ t-1} + CPI_{Dec,\ t-1}} - 1 \right)$$

where:

CPI is the consumer price index, All Groups index number for the weighted average of eight capital cities as published by the Australian Bureau of Statistics

t refers to the financial year, and

the corresponding subtext (for example, June, *t-1*), means the CPI for the quarter and of the financial year indicated (in the example, the quarter ending in June of the financial year immediately before financial Year *t*).

The Tribunal based its CPI measure on December quarter data to allow DNSPs sufficient time to prepare their pricing proposals, and for the Tribunal to review these proposals in time for final prices to be published on 31 May each year. The Tribunal considers this to be preferable to using March data and compressing the time available for the price approval process. In general, stakeholders support the use of December CPI data.

The Tribunal's use of an average of four quarters, year-on-year definition (rather than a quarter-on-quarter approach) provides a more stable measure, and one that better reflects the flow of income that DNSPs receive throughout the year. This approach is consistent with the definition applied across all sectors that the Tribunal regulates, and is generally supported by stakeholders. The Tribunal saw no reason to move away from the CPI for eight capital cities measure in favour of a Sydney-based measure.

Calculating the amount by which average prices can change – the X-factors

The X-factor in the weighted average price cap formula determines how prices for DUOS tariffs can change in real terms over the regulatory period. To set the X-factor values for the weighted average price cap, the Tribunal has:

- undertaken a building block analysis to determine a notional revenue requirement for each year of the regulatory period for each DNSP
- taken the notional revenue requirements and, using growth forecasts, converted them into average allowable real price changes (the X-factors)

- adjusted the X-factors to ensure acceptable outcomes for all stakeholders and compliance with the principles and objectives of the National Electricity Code
- testing the resulting 'smoothed' annual revenue requirements using financial analysis to ensure they will allow the DNSPs to remain financially viable.

In deciding how to spread these price changes over the regulatory period, the Tribunal has used a hybrid of the P-nought and straight line (glide path) approaches. All the DNSPs will be allowed a larger real price increase in the first year of the regulatory period, and a smaller increase in each of the remaining years.

The Tribunal's process, analysis and considerations in relation to calculating the amount by which prices can change are discussed in Chapters 4 to 7.

Demand management cost recovery factor — D-factor

The Tribunal has decided that it will introduce a D-factor into the weighted average price cap control formula that allows DNSPs to recover:

- **approved non-tariff-based demand management implementation costs, up to a maximum value equivalent to the expected avoided distribution costs**
- **certain approved tariff-based demand management implementation costs**
- **approved revenue foregone as a result of non-tariff-based demand management activities.**

The D-factor for Year *t+1* will be calculated as follows:

$$D_{t+1} = \frac{DM\ Cost\ Pass\ Through\ Amount_{t+1}}{SRR_t - AF\ Revenue_{t\text{-}1}} - \frac{DM\ Cost\ Pass\ Through\ Amount_t}{SRR_{t-1} - AF\ \ Revenue_{t\text{-}2}}$$

Where:

D_{t+1}	is the D-factor to be included in the price control formula for Year *t+1*
AF Revenue $_{t-1}$	is the amount approved by the Tribunal for recovery by the DNSP of foregone revenue in Year *t-1*
AF Revenue $_{t-2}$	is the amount approved by the Tribunal for recovery by the DNSP of foregone revenue in Year *t-2*
DM Cost Pass Through Amount $_{t+1}$	is the DM Cost Pass Through Amount calculated for the DNSP for the Year *t+1* — the sum of approved demand management implementation costs and foregone revenue incurred in Year *t-1*, as approved by the Tribunal
DM Cost Pass Through Amount $_t$	is the DM Cost Pass Through Amount calculated for the DNSP for the Year *t*
SRR_t	is the smoothed revenue requirement for the DNSP for the Year *t*

SRR_{t-1} is the smoothed revenue requirement for the DNSP for the Year *t-1*.

The Tribunal's decisions in relation to the D-factor and the analysis behind these decisions are discussed in Chapter 8.

3.3.2 Charges for miscellaneous and monopoly services and recoverable works for emergency services

For its final decision the Tribunal has determined an exhaustive list of maximum charges for miscellaneous services and mandatory fees for monopoly services, indexing the current prices to 2004 dollars. For recoverable works for emergency services, the Tribunal has determined a set of pricing principles.

The Tribunal considers that charges for miscellaneous and monopoly services are prescribed distribution charges. It included the costs for these services in the notional revenue requirement before the X-factors were calculated for the DUOS tariffs. When the Tribunal assesses DNSPs' compliance with the weighted average price cap, charges for miscellaneous and monopoly services will be included in the weighted average price cap.

Miscellaneous charges and monopoly fees are subject to a zero nominal price limit, and so will remain unchanged from the values listed in Annexure 3 of the Determination for the length of the regulatory period.

As foreshadowed in the draft determination, the Tribunal has now determined how recoverable works–emergencies are to be treated. The Tribunal has determined a set of pricing principles that set a ceiling on these charges.

The Tribunal's decisions and considerations on charges miscellaneous and monopoly services and recoverable works for emergency services are discussed in Chapter 9.

3.3.3 Integrated package of incentives for service quality

The Tribunal has decided to introduce an integrated package of measures to provide incentives for service quality, consisting of the following components:

- the collection and publication of service standards performance statistics, covering service reliability, quality of supply and customer service
- a 'paper trial' S-factor, focusing on service reliability measures (but no monetary S-factor)
- subject to the Minister for Energy and Utilities' approval, an expanded set of Guaranteed Customer Service Standards, covering service reliability, quality of supply and some customer service measures.

The Tribunal's decisions in relation to providing incentives for service quality are discussed in Chapter 10.

3.3.4 Cost pass through arrangements

The Tribunal has decided to introduce a specific cost pass through mechanism for costs incurred for the following specified events:

- **potential changes in occupational health and safety requirements governing live-line working procedures**
- **potential amendments to the Electrical Supply Act seeking to clarify the definition of 'electrical installation and point of supply'**
- **possible introduction of additional payments linked to Guaranteed Customer Service Standards (GCSS) as a result of IPART's recommendations to the Minister for Energy and Utilities to introduce payments linked to network reliability**
- **possible changes in the Government's policy on interval/time based metering, which may entail a more widespread roll-out of interval or other meters to customers.**

The Tribunal has also decided to introduce a general cost pass through mechanism, allowing for the pass through of approved costs or cost savings in the following circumstances:

- **changes in certain taxation obligations**
- **changes in certain regulatory obligations.**

DNSPs will be required to apply for the pass through of incremental costs (or cost savings in the case of the general pass through mechanism). Both the level of the pass through amounts and the profile of recovery will be approved by the Tribunal. The pass through of approved costs will be outside the price limits on network tariffs.

The Tribunal's decisions in relation to the cost pass through arrangements are discussed in detail in Chapter 11.

3.3.5 Recovery of transmission-related payments through transmission cost recovery tariffs

The Tribunal has decided that DNSPs can recover transmission-related costs by setting transmission cost recovery tariffs to recover:

- **transmission charges they expect to pay to transmission network service providers**
- **avoided TUOS payments they expect to pay to embedded generators, calculated in accordance with the Code**
- **inter-distributor transfer payments they expect to make to other DNSPs.**

Once the actual transmission charges, avoided TUOS payments and inter-distributor transfer payments are known, they will be offset against actual revenue collected by the DNSPs through their transmission cost recovery tariffs. Any under or over recovery of the costs will be recorded in a transmission overs and unders account.[22] Recovery (or return) of the balance in the account can occur at the next price change date, via an adjustment to transmission cost recovery tariffs, subject to the price limits on network tariffs. The Tribunal

[22] Any outstanding balances in the account will attract a nominal return, based on the nominal rate of return, to compensate for the time value of money.

may authorise departure from the price limits on network tariffs if a significant balance accumulates in the transmission overs and unders account.

The Tribunal's decisions in relation to the recovery of transmission related costs are discussed in detail in Chapter 13.

3.3.6 Price limits on network tariffs and other fees

The Tribunal has decided that it will set price limits on network tariffs and other fees, for all customers — both residential and non-residential — except for larger customers on individually calculated (CRNP) tariffs, as set out in Table 3.2.

Table 3.2 Price Limits for 2004-09 regulatory period[23]

DNSP	Price limit for 2004/05	Price limit for each year 2005/06-2008/09
ALL DNSPS	ΔCPI + 7.0%	ΔCPI + 4.5%
All DNSPs, each year	• Maximum increase in fixed charge of residential tariffs $30 per year • Zero nominal increase for miscellaneous charges and monopoly fees and charges for recoverable works for emergency services	

These price limits are intended to protect customers against significant price shocks as a result of tariff restructuring. In establishing the limits, the Tribunal has sought to provide DNSPs with sufficient headroom above the constraint imposed by the weighted average price cap to allow tariff restructuring. The Tribunal has provided for departure from the price limits for increases in transmission charges, where these may lead to an accumulated balance in the transmission overs and unders account of 15 per cent of actual transmission-related payments incurred in the previous year.

The price limits will apply to individual network tariffs and will have the form:

$$\frac{\sum_{j=1}^{m} r_j^{t+1} * q_j^{t-1}}{\sum_{j=1}^{m} r_j^{t} * q_j^{t-1}} \leq 1 + \Delta CPI + L_{t+1}$$

where:

the Network Tariff has up to m aggregate components

an aggregate component of a Network Tariff means the aggregate of any DUOS Tariff component and its corresponding Transmission Cost Recovery Tariff component (if any), in accordance with clause 7.2 of the determination

r_j^{t+1} is the proposed price for aggregate component *j* of the Network Tariff for Year *t+1*

23 Applies to each residential and non-residential tariff, excluding CRNP (cost reflective network pricing) tariffs and rebates.

r_j^t is the price charged by the DNSP for aggregate component *j* of the Network Tariff in Year *t* (being the Year immediately preceding Year *t+1*)

q_j^{t-1} is the Audited Quantity of aggregate component *j* of the Network Tariff that was charged by the DNSP in Year *t-1* (being the Year immediately preceding Year *t*)

L_{t+1} is the price limit for Year *t+1*, and

ΔCPI is the change in the Consumer Price Index over the 12 month period from January of the Year *t-1* to December of the Year *t*, compared with the preceding 12 month period.

The Tribunal has also imposed a maximum increase in fixed charges of $30 per year for residential customers. In addition, it has decided that miscellaneous and monopoly fees may not be increased in nominal terms from their 2004/05 values. It has also decided that the cost pass through arrangements discussed in section 3.3.4 are not subject to the limits on price movements.

Full details of the Tribunal's decision on the network price limits are set out in Chapter 14.

3.3.7 Network price setting arrangements

The Tribunal has established an alternative pricing methodology to that set out in Part E of Chapter 6 of the Code. This methodology sets out the arrangements the DNSPs must follow when setting prices and making tariff changes during the 2004-2009 regulatory period.

The key elements of the Tribunal's alternative pricing methodology are:

- a set of pricing principles that the DNSPs must apply in setting their total network tariffs
- requirements for information disclosure and public consultation
- a process for assessing the compliance of annual pricing proposals with the determination
- default pricing arrangements in the event a non-compliant proposal is received.

The Tribunal's alternative pricing methodology is discussed in detail in Chapter 15.

3.3.8 Regulation of excluded distribution services

The Tribunal has decided to apply a 'light handed' form of regulation to excluded distribution services. Chapter 16 sets out the regulatory arrangements to apply to these services.

4 DETERMINING APPROPRIATE GROWTH FORECASTS AND TOTAL COST LEVELS

As Chapter 3 discussed, the Tribunal's approach for setting the weighted average price cap involves using the building block methodology to determine each DNSP's notional annual revenue requirements over the regulatory period. As part of this approach, the Tribunal must determine:

- growth forecasts in each DNSP's area of operation over this period
- how much of each DNSP's capital expenditure during the 1999-2003 regulatory period it considers to be prudent
- how much of each DNSP's projected capital expenditure for the 2004-09 regulatory period it considers to be efficient
- how much of each DNSP's projected operating and maintenance expenditure it considers to be efficient.

Growth forecasts have a critical impact on a DNSP's revenue requirements. For example, if a higher growth rate is forecast, operating and maintenance expenditure is likely to be higher, to enable the DNSP to meet the greater demands on its network. Higher growth could also necessitate greater capital expenditure, as assets might need to be replaced sooner or there might be a need to expand the capacity of the network to meet higher levels of demand. Growth forecasts also affect the calculation of the X-factors in the weighted average price cap (see Chapter 7). The Tribunal also notes that the DNSPs have a theoretical incentive under a weighted average price cap to underestimate growth forecasts.

The level of prudent capital expenditure for 1999-2003 and the level of efficient projected capital expenditure for 2004-09 are important inputs for calculating the return on and of capital building blocks. The Tribunal includes allowances for these levels of expenditure when it rolls forward the regulatory asset base. The level of efficient projected operating and maintenance expenditure determines the allowance for the operating and maintenance expenditure building block. For this determination, the Tribunal considered the DNSPs' past capital expenditure and projected capital and operating expenditure together, including commissioning consultants to review these total costs. This total cost approach recognises that there is potential for the DNSPs to trade off capital expenditure for operating expenditure and vice versa, and that this could affect their service quality.

This chapter sets out the Tribunal's final decisions on growth forecasts, prudent capital expenditure for 1999-2003, efficient capital expenditure for 2004-09 and efficient operating and maintenance expenditure for 2004-09. It also discusses stakeholder responses to the draft decisions on these issues and the Tribunal's considerations in reaching its final decisions.

4.1 Final decisions on growth forecasts

The Tribunal has decided to adopt the growth forecasts shown in Table 4.1 when setting the weighted average price caps for the 2004-09 regulatory period.

Table 4.1 Growth forecasts adopted in final determination

DNSP	Average GWh growth p.a.	Average customer growth p.a.
EnergyAustralia	2.1%	1.7%
Integral Energy	2.1%	1.9%
Country Energy	1.7%	1.8%
Australian Inland	2.0%	0.3%

These growth forecasts are based on the analysis undertaken by the Tribunal's consultants, McLennan Magasanik Associates (MMA).

4.1.1 Summary of draft decisions on growth forecasts and stakeholder responses

During the review, the Tribunal's Secretariat released a discussion paper on determining the likely growth in the DNSPs' sales volumes.[24] In their responses to this paper, stakeholders expressed support for an independent review of growth forecasts submitted by the DNSPs. As a result, the Tribunal commissioned a consultant, McLennan Magasanik Associates (MMA) to evaluate these growth forecasts, and to provide its own independent growth forecasts for each DNSP.

In its draft report, the Tribunal indicated that it intended to adopt the MMA growth forecasts for the purpose of setting the weighted average price cap. These forecasts differed from the DNSPs' by varying amounts. The largest difference was between the MMA draft forecasts and EnergyAustralia's forecasts.[25]

Because the Tribunal did not have operating and capital expenditure estimates from the DNSPs that were consistent with the MMA draft forecasts at the time it made its draft determination, it used as an approximation the medium growth and cost scenarios provided by Integral Energy, Country Energy and Australian Inland, and the high growth and cost scenarios provided by EnergyAustralia. It invited the DNSPs to submit estimates of the changes in costs they would expect to incur if the MMA draft forecasts were adopted, so that these could be assessed for efficiency prior to the final determination. It also published the MMA draft report on its website for comment.

24 IPART Secretariat, *Determining Sales Volumes for the 2004 Electricity Network Review,* July 2003. Available on IPART's website (www.ipart.nsw.gov.au).

25 See Tables 4.1 and 4.2, IPART, *NSW Electricity Distribution Pricing 2004/05 to 2008/09 – Draft Report*, January 2004.

The Tribunal received several responses to its draft decisions and MMA's draft growth forecasts:

- EnergyAustralia expressed a number of concerns with the MMA draft forecasts and the underlying methodology. EnergyAustralia argued that the MMA draft forecasts were too high, and, amongst other comments, suggested that MMA had failed to take into account a number of factors specific to the EnergyAustralia region. It also disagreed with the way MMA had taken into account weather and day type effects.
- Country Energy was also concerned about the MMA draft forecasts, and also suggested MMA had failed to take into account features specific to the Country Energy region. It argued that the forecasts provided by its own consultants, The National Institute of Economic and Industry Research (NIEIR), were more robust for its region.
- Integral Energy did not agree with the methodology adopted by MMA, but accepted the Tribunal's decision to use these forecasts as they were very similar its own forecasts, except for peak demand, where MMA forecast a higher level of growth.
- The Energy Users Association of Australia (EUAA) suggested that MMA had made insufficient allowance for the likely impacts of increased air-conditioning penetration over the coming regulatory period.

4.1.2 Tribunal's considerations in making final decisions on growth forecasts

The Tribunal reviewed the comments made by stakeholders in response to the draft growth forecasts, and passed these comments on to MMA for its consideration. At a public forum held on 18 March 2004, MMA presented the findings of its draft report, and stakeholders were given a further opportunity to comment.

In producing its final report,[26] MMA took into account the comments provided by stakeholders. It also took into account any updated information that was available, including:

- the likely impact of the proposed Building Sustainability Index (BASIX) energy efficiency regulations
- Country Energy's update on its actual demand for 2002/03
- Australian Inland's updated growth forecasts, which reflected the fact that demand in the past year has not been as badly affected by the drought as had been originally envisaged.

A copy of MMA's final report which explains its considerations in further detail is available on the IPART website. Its key conclusions were as follows:

- For EnergyAustralia, MMA revised its draft forecast for residential consumption slightly downwards, from 2.20 per cent average growth per annum (2004/05 to 2008/09) to 2.12 per cent, and made a small reduction in its forecast for summer peak demand (0.9 per cent lower by 2009).
- For Integral Energy, MMA found that no revisions to its initial forecasts were required.
- For Country Energy, following further discussions with the DNSP and after incorporating the fact that Country Energy's 2002/03 total demand is substantially

26 *Review of Demand Forecasts by the Electricity Distribution Network Service Providers for the 2004 Electricity Network Review*, Final Report to IPART, April 2004, published on IPART's website June 2004.

higher than initially expected,[27] MMA considered that based on the limited data available, the most appropriate course of action would be to apply the NIEIR growth forecasts to the 2002/03 actual demand. Country Energy agreed with this.

- For Australian Inland, MMA accepted the DNSP's revised growth projections as a reasonable forecast for regulatory purposes.

For Integral Energy, Country Energy and Australian Inland, the MMA final GWh growth forecast is the same or very similar to that provided by the DNSP in its final submission to the Tribunal, but for EnergyAustralia the MMA forecast remains tangibly higher than the DNSP's own forecast (Table 4.2). For Integral Energy and EnergyAustralia, the MMA final forecast for summer peak demand is also higher than the DNSPs'.[28]

Table 4.2 Average GWh growth, 2004-09 (% pa)

DNSP	MMA Final Report	DNSP Final Submission*
EnergyAustralia	2.1	1.7
Integral Energy	2.1	2.0
Country Energy	1.7	1.7
Australian Inland	2.0	2.0

* March 2004.

Table 4.3 Summer peak demand growth rates (% pa)

DNSP	MMA Final Report	DNSP Final Submission*
EnergyAustralia	3.3	2.9
Integral Energy	3.1	2.9
Country Energy	2.8	2.9

* March 2004.

The Tribunal is satisfied with the analysis and considerations outlined in the final MMA report. Accordingly, the Tribunal affirms its decision to adopt the MMA forecast growth rates for purposes of calculating allowed revenues for the 2004-09 regulatory period.[29]

Integral Energy, Country Energy and Australian Inland provided the Tribunal with cost projections consistent with these growth assumptions. EnergyAustralia provided cost projections based on the MMA *draft* growth assumptions for 2004/05 to 2008/09. Although MMA's *final* growth assumptions are slightly lower, the Tribunal considers the cost projections provided by EnergyAustralia are still an appropriate basis for calculating allowed revenues, particularly given that any demand forecast is always likely to be subject

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27 Country Energy's 2002/03 regulatory accounts showed non-residential sales to have increased by 11 per cent from 2001/02, and residential sales to have fallen by 3.5 per cent, giving an overall increase of 4.5 per cent.

28 MMA did not forecast peak demands for Australian Inland due to insufficient data.

29 Note that the Tribunal made some adjustments to the EnergyAustralia 2003/04 demand figure onto which the MMA forecast growth rates are applied, to allow for more recent demand information. For the other DNSPs, the MMA forecast growth rates are applied to the 2002/03 actual audited figures.

to a certain margin of error. However, it should be noted that if anything, this implies that the Tribunal is taking a slightly cautious approach on cost assumptions for EnergyAustralia.

4.2 Final decisions on prudent capital expenditure for 1999-2003

The Tribunal has decided that each DNSP's capital expenditure for the period 1998/99 to 2002/03 was prudent. It therefore included an allowance for this expenditure, shown in Table 4.4, when rolling forward the regulatory asset base from 1999 to 2003.

Table 4.4 Capital expenditure included in the roll forward of the regulatory asset base ($million, nominal)

	1999	2000	2001	2002	2003
EnergyAustralia	141	256	272	293	294
Integral Energy	98	98	97	147	148
Country Energy	147	124	142	181	221
Australian Inland	3	3	3	4	3

EnergyAustralia's numbers include transmission assets.

4.2.1 Summary of draft decisions on prudent capital expenditure and stakeholder responses

The Tribunal's draft decisions in relation to capital expenditure for the period 1998/99 to 2002/03 was the same as its final decision. It did not receive many stakeholder responses to these decisions. The Energy Markets Reform Forum expressed disappointment that it had agreed to the DNSPs' $1 billion overruns.[30]

4.2.2 Tribunal's considerations in making final decisions on prudent capital expenditure

In making its final decisions on prudent capital expenditure over the 1999-2003 regulatory period, the Tribunal gave careful consideration to the fact that all four DNSPs spent considerably more than they projected in their submissions for the 1999 determination, and than the Tribunal allowed for in the 1999 determination (Table 4.5).

Table 4.5 Projected and actual capital expenditure 1998/99 to 2002/03

$M (1998 prices)	EnergyAustralia	Integral Energy	Country Energy	Australian Inland
Tribunal's allowance	885	412	793	16
Actual (nom)	1,383	778	1,002	21
Actual (real $1998)	1,266	708	916	19

Source: Meritec, Capital and Operating Expenditure, Final Report, October 2003, Table 6A.
Notes: Covers full period from 1998/99 to 2002/03.
Includes capital contributions, metering and streetlighting.

30 Energy Markets Reform Forum submission, in response to IPART's draft report, March 2004, p 1.

The DNSPs argued that all of this expenditure was prudent, and emphasised in particular the unexpected high growth in electricity demand, especially in peak periods. Integral Energy also emphasised the need to make greater replacements to its ageing asset base, and declining service quality beyond that envisaged at the time of the determination.

EnergyAustralia commissioned Sinclair Knight Merz (SKM) to assess the prudence of its spending on major projects between 1999/00 to 2003/04. SKM concluded that all the projects it assessed were prudent, based on the information available at the time. However, it noted that "… some reconsideration of scope and timing may have been warranted, based on information that came to hand after the initiation of the project."[31] Integral Energy commissioned PB Associates to assess the prudence of some of its capital expenditure projects. PB Associates found that the expenditures it examined were prudent.

The Tribunal asked Meritec to review the prudence of each DNSP's capital expenditure over the 1998/99 to 2002/03 period. Meritec found "no reason to judge the individual project and programme expenditures incurred during the period imprudent".[32] In relation to the DNSPs' higher than projected capital spending, it noted a range of factors that contributed to this over spending—including:[33]

- significant non-system capital expenditure overruns
- in some cases, significant expenditure on IT system improvements
- higher than expected growth in demand (especially in the Sydney area)
- evidence of air conditioning load growth and a shift in peak demand from winter to summer in some locations
- DNSPs' perceived need for increased expenditure on refurbishment (although this category of expenditure was not a major contributor to the total over-spend, Meritec noted that asset ages did not suggest there was any urgency to undertake this work)
- additional statutory obligations.

On balance, based on its own analysis and Meritec's findings, the Tribunal decided to accept Meritec's recommendation that capital expenditure during the period 1998/99 to 2002/03 was prudent.

31 See EnergyAustralia April 2003 submission, Attachment 11, p 1, available on IPART's website.

32 Meritec Ltd, *Capital and Operating Expenditure - Final Report*, October 2003, p 23.

33 ibid, pp 22-23.

4.3 Final decisions on efficient capital expenditure for 2004-09

The Tribunal has decided that the projected capital expenditure shown in Table 4.6 is efficient. It therefore included an allowance for this expenditure when estimating the roll forward of the regulatory asset base from 2003 to 2009.

Table 4.6 Projected capital expenditure allowed for when rolling forward the regulatory asset base ($million, nominal)

	2004	2005	2006	2007	2008	2009
EnergyAustralia	312	403	411	420	421	441
Integral Energy	272	285	304	282	291	258
Country Energy	229	240	245	248	257	264
Australian Inland	5	5	4	3	3	3

In making this final decision, the Tribunal has:

- Reduced EnergyAustralia's proposed capital expenditure under its medium growth scenario by 6.2 per cent per annum;[34] and added $155m of EnergyAustralia's proposed additional capital expenditure to match MMA's growth forecast.
- Reduced Integral Energy's proposed capital expenditure under its medium growth scenario by 9 per cent per annum;[35] added $65m for security fencing and relocation expenses; and added $55m to match MMA's growth forecast.
- Allowed Country Energy's proposed capital expenditure under its medium growth scenario (which aligns with MMA's forecast); added $13m for security fencing; and did not allow $75m for the advancement of sub-transmission works.
- Allowed Australian Inland's proposed capital expenditure program under its medium growth scenario (which aligns with MMA's forecast); added $1m for security fencing and $1m for growth; ($2m less that proposed by the DNSP).

34 Meritec recommended that all of the growth component of EnergyAustralia's capital expenditure should be allowed (1.6 per cent of network replacement cost), but that the remainder of the expenditures should be reduced from 2.4 per cent of network replacement cost to 2.0 per cent. That is, a reduction in the total capital expenditure allowance from 4.0 per cent of network replacement cost to 3.6 per cent. This equates to a 6.2 per cent reduction in capital expenditure for EnergyAustralia per annum for 2004-09, or roughly $24 million per annum, or $119 million over the 2004-09 period. Similarly, for Integral Energy, Meritec recommended that all of the growth component of capital expenditure be allowed (1.7 per cent of network replacement cost) but that the remainder of the expenditure should be reduced from 2.8 per cent of network replacement cost to 2.4 per cent. That is, a reduction in the total capital expenditure allowance from 4.5 per cent of network replacement cost to 4.1 per cent. This equates to a 12.6 per cent reduction in capital expenditure for 2004-09, or about $32 million per annum.

35 Ibid.

4.3.1 Summary of draft decision on efficient capital expenditure and stakeholder responses

The Tribunal's final decision on efficient capital expenditure largely affirms its draft decision. However, the Tribunal based its draft decision on EnergyAustralia's high growth capital expenditure projections which included additional capital expenditures of $311m to meet the higher growth levels. In its draft determination, the Tribunal:

- Reduced EnergyAustralia's proposed capital expenditure under its medium growth scenario by 6.2 per cent per annum,[36] then added all of EnergyAustralia's proposed additional capital expenditure under its high growth scenario ($311m).
- Reduced Integral Energy's proposed capital expenditure under its medium growth scenario by 9 per cent per annum.[37]
- Allowed all of Country Energy's and Australia Inland's proposed capital expenditure program under their medium growth scenarios.

Stakeholders' responses to the draft decisions differed widely:

- The Energy Users Association submitted that the draft decisions were too generous, and that DNSPs' capex proposals were excessive by a large margin. It argued that the Tribunal should allow capex of $3.1 billion ($1.7 billion less than the DNSPs' proposed).[38]
- Origin commented that Meritec had not sufficiently explained its analysis of the DNSPs' capex projections.[39]
- PIAC[40] put the view that residential customers would welcome even the limited reductions proposed by Meritec and agreed to by the Tribunal.
- EnergyAustralia commented that the Tribunal's approach of ensuring that capex is consistent with the underlying drivers of peak demand and forecast consumption is valid. However, it pointed out that in its April 2003 submission it had implicitly assumed that real hourly wage rates and the real cost of installing capital will not increase over the life of the determination. EnergyAustralia submitted that real wages are increasing at a higher rate than inflation, and that the Tribunal must therefore make an upward adjustment for this.
- Country Energy submitted that Meritec's modelling and analysis in relation to its projected capex was detailed and rigorous.
- Integral Energy opposed the Tribunal's decision to reduce its proposed capital expenditure by 9 per cent per annum.
- AGL ES&M argued that the costs of providing interval meters to customers using less than 160MWh should not be included in DNSPs' efficient capital expenditure allowance and that this work is not cost effective and should not proceed until a cost benefit assessment is undertaken. It expressed a strong concern that for each electricity retailer, the costs of building new IT systems to accept interval meter data will be many

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36 Ibid.

37 Ibid.

38 Energy Users' Association of Australia submission to the Electricity Network Draft Determination, March 2004.

39 Origin submission to the Electricity Network Draft Determination, March 2004.

40 PIAC submission to the Electricity Network Draft Determination, March 2004, p 2.

millions of dollars. In addition, retailers will not be able to build, test and operate these systems for a considerable time, even if they are funded by increased prices to customers. It argued that the need to do this will be the most significant barrier to entry to the NSW electricity market, and will give the incumbents an overwhelming competitive advantage.[41]

4.3.2 DNSP revisions to projected capital expenditure

After the draft determination and MMA's draft growth forecasts were released, the Tribunal asked DNSPs to provide revised capital expenditure projections to align with MMA's forecasts. Their revised projections are shown in Table 4.7.

Table 4.7 DNSPs' additional projected growth-related capital expenditure 2004-09 ($million, nominal)

	Energy Australia	Integral Energy	Country Energy	Australian Inland
DNSP projected capex under medium growth, April 03 submissions	2,128	1,391	1,240	15
Tribunal proposed capex, draft report	2,263[1]	1,268	1,240	15
DNSP additional capex under MMA growth forecast	155[2]	55	88	3

Notes:
1. In its draft report, the Tribunal used EnergyAustralia's high growth costs as an approximation to match MMA growth.
2. Additional to EnergyAustralia's medium growth scenario.

In addition, three of the DNSPs revised the capital expenditures projections provided in their April 2003 submissions to include additional non-growth related capital expenditure that they were not aware of at that time. Table 4.8 summarises these additional non-growth related amounts.

Table 4.8 DNSPs' additional projected non-growth capital expenditure ($million, nominal)

	Energy Australia	Integral Energy	Country Energy	Australian Inland
Live line	nil	7	20	-
Security fencing[42]	nil	53	13	1
GCSS[43]	nil	2	6	1
Interval meters	nil	30	-	-
MSATS procedures	nil	4	-	-
Other	nil	11	83	3
Total	**nil**	**107**	**122**	**5**

41 AGL ES&M submission to the Electricity Network Draft Determination, March 2004.

42 EnergyAustralia included costs for substation security fencing in its April 2003 submission.

43 EnergyAustralia noted that some costs would be incurred to implement the GCSS draft recommendations, but did not quantify these or include them in their capital expenditure projections.

GCSS: Guaranteed Customer Service Standards.
MSATS: Market Settlement and Transfer Solution.

The Tribunal engaged a consultant, Wilson Cook, to review the DNSPs' projections for additional growth and non-growth capital expenditures, to ensure the projections are reasonable and efficient. Wilson Cook provided a draft report in April 2004, and the Tribunal invited public comment on this draft. Wilson Cook's final report was received in May 2004. Both these reports are available on the IPART website.

4.3.3 Tribunal considerations in making final decisions on efficient capital expenditure

In making its final decisions on the levels of efficient projected capital expenditure for 2004-09, the Tribunal has carefully considered the issues raised by stakeholders, the DNSPs' additional projected expenditures, Meritec's review of the DNSPs' projected expenditures, and Wilson Cook's review of these additional projected expenditures. Its considerations in relation to each DNSP are outlined below.

EnergyAustralia

EnergyAustralia commissioned SKM to help it calculate how much additional projected capital expenditure it would need (on top of the expenditure proposed in its medium growth 2003 submission to the Tribunal) to reflect the MMA growth forecasts. It submitted that it would need a total of $155 million additional growth related expenditure. A breakdown of this amount is shown in Table 4.9. In its draft report the Tribunal had included an additional $311m of growth related capital expenditure.

Table 4.9 EnergyAustralia's projected additional growth related capital expenditure ($million, nominal)

	2005	2006	2007	2008	2009
Replacement capex	-1.3	-0.2	5.2	7.1	-0.6
Environmental and safety	0	0	0	0	0
Non-network	0	0	0	0	0
Total renewal /replacement capex	-1.3	-0.2	5.2	7.1	-0.6
Growth (demand related)	21.3	21.0	33.3	22.5	34.1
Reliability	1.6	1.5	1.7	2.0	2.1
Sub total	21.5	22.3	40.2	31.6	35.6
Metering	0.8	0.8	0.8	0.8	0.8
Total	**22.3**	**23.1**	**41.0**	**32.4**	**36.4**

Source: Wilson Cook.

Wilson Cook's review of this expenditure found that it was reasonable and efficient. Wilson Cook also noted that EnergyAustralia's projected investment per MWh of growth under its own medium-growth forecast ($436) was considerably higher than its projected investment per MWh of growth under the MMA growth forecast ($394).[44] It pointed out that while this is a simplistic comparison, it provides additional comfort that the revised projections of growth related capital expenditure are not excessive.

44 Wilson Cook & Co Ltd, *Review of Revised Operating and Capital Expenditure of DNSPs*, April 2004.

In addition, Wilson Cook noted that another consultant, GHD, had made adverse findings on EnergyAustralia's system planning and approval process in a 2004 report to the ACCC.[45] However:

> … this did not affect our opinion for the following reasons amongst others: (a) EA had provided Meritec with independent reviews of its distribution-related capex and opex, prepared by SKM, (in addition to SKM's 2004 review) and the review did not express the same reservations as GHD's report; (b) we would not expect to find the same level of detailed project information for planning purposes at the distribution level as at the transmission level as the work is more generic in nature, often comprising programmes rather than projects; and (c) we noted that Meritec had received supporting papers related to selected major projects for distribution works, including the study of alternatives, and found them acceptable. [46]

After considering its consultants' findings, stakeholder comments and its obligations under the Code, the Tribunal decided to allow the projected capital expenditure for EnergyAustralia shown in Table 4.6. Table 4.10 shows how this amount was derived.

Table 4.10 EnergyAustralia's allowed capital expenditure for 2004/05 to 2008/09 ($million, nominal)

	2004/05	2005/06	2006/07	2007/08	2008/09
Expenditure allowed in draft report	443	452	454	446	468
Adjustment due to MMA growth forecasts[1]	-40	-41	-34	-25	-27
Total expenditure allowed per Table 4.6	403	411	420	421	441

Note

1 Adjustment includes removal of $10m of demand management learn by doing capex included in the draft determination.

Totals may not add due to rounding.

In making this decision, the Tribunal recognises that maximum demand and particularly summer demand is a strong driver of the DNSPs' capital expenditure. However, the forecast capital expenditure for EnergyAustralia in this final report is lower than those proposed in the draft report as capital expenditures required by EnergyAustralia to match the MMA growth forecast is lower than required under their high growth scenario.

In relation to EnergyAustralia's request that an adjustment be made to its capital expenditure projections to reflect the fact that the real wage rate and construction costs have increased by more than inflation, the Tribunal decided not to allow this adjustment. It considers that EnergyAustralia should have been able to adequately forecast wage movements prior to submitting its April 2003 submission. In addition, EnergyAustralia did not submit this proposed change to Wilson Cook, so this expenditure has not been reviewed for efficiency.

45 ACCC, *EnergyAustralia Regulatory Review Capital Expenditure and Asset Base, Operational Expenditure and Service Standards Report*, March 2004.

46 Wilson Cook & Co Ltd, *Review of Revised Operating and Capital Expenditure of DNSPs*, April 2004, p 10.

In relation to AGL ES&M's concerns about allowing for expenditure for installing interval meters, the Tribunal notes that EnergyAustralia, in its April 2003 submission, included $46m of expenditures associated with providing interval meters to large users (>15MWh). EnergyAustralia stated that this expenditure will facilitate tariff reform. As Meritec reviewed this expenditure and found that it was efficient, the Tribunal has allowed it. However, if EnergyAustralia installs interval meters in place of accumulation meters that are not at the end of their effective lives, the regulator may need to adjust its regulatory asset base at the next regulatory review if it concludes that the expenditure is not prudent.

Integral Energy

Integral Energy submitted that it would need a total of $55 million additional growth related expenditure to reflect MMA's higher forecast for summer peak demand. A breakdown of this amount is shown in Table 4.11.

Table 4.11 Integral Energy's projected additional growth related capital expenditure ($million, nominal)

	2005	2006	2007	2008	2009
Replacement	1.9	-1.9	-2.0	-2.0	-2.1
Environmental and safety	0	0	0	0	0
Non-network	0	0	0	0	0
Total renewal/replacement	1.9	-1.9	-2.0	-2.0	-2.1
Growth (demand related)	-10.5	21.5	18.1	16.9	14.2
Reliability	0	0	0	0	0
Total	**-8.6**	**19.6**	**16.1**	**14.9**	**12.1**

Source: Wilson Cook.

Wilson Cook's review of this expenditure found that it was reasonable and efficient. Wilson Cook also noted that Integral Energy's projected investment per MWh of growth under its own medium-growth forecast ($447) was somewhat higher than its projected investment per MWh of growth under the MMA growth forecast ($435).[47]

On 31 March 2004, Integral Energy advised the Tribunal that it would need a further $11m of projected capital expenditure, due to a planned change in scope for the relocation of its Transmission and Distribution Groups from the current depot at Seven Hills. Wilson Cook reviewed this additional expenditure and found it to be reasonable and efficient.

[47] Wilson Cook & Co Ltd, *Review of Revised Operating and Capital Expenditure of DNSPs*, April 2004.

Integral Energy also submitted a range of other revisions to the projected capital expenditures it proposed in its 2003 submission to the Tribunal. These related to:

- **Pre-demand management costs.** Integral Energy's original capital expenditure projections (used for the draft determination) were not on a pre-demand management basis, as required by the Tribunal.[48] It submitted adjustments to exclude the impact of planned demand management projects on the deferral of capital expenditures. Wilson Cook reviewed these adjustments and concluded that they are reasonable and efficient.
- **Substation security.** Integral Energy engaged a consultant to review its substation security in response to a coronial finding on a death at a substation in 2002. Based on this review, it proposes to spend $53m on fencing at 166 substations. Wilson Cook reviewed this proposed expenditure. It pointed out that although the proposed expenditure per substation is higher than that proposed by the other DNSPs, Integral Energy's forecasts are based on a comprehensive review and tender process and therefore may be more accurate. It concluded that the additional expenditure is reasonable and efficient.
- **Guaranteed Customer Service Standards (GCSS).** Integral Energy projected that it would need $2m additional capital expenditure to implement the changes to the GCSS proposed by the Tribunal in its draft report to the Minister.
- **Market Settlement and Transfer Solution (MSATS) Procedure.** It projected it would need $4m additional capital expenditure to implement electronic transactions and transfers between network and retailers. The transactions and transfers relate to metering data, customer transfers, use-of-system charges arising from retail contestability.

After considering its consultants' findings, stakeholder comments and its obligations under the Code, the Tribunal decided to allow the projected capital expenditure for Integral Energy shown in Table 4.6. Table 4.12 shows how this amount was derived.

Table 4.12 Integral Energy's allowed projected capital expenditure 2004/05 to 2008/09 (millions, nominal)

	2004/05	2005/06	2006/07	2007/08	2008/09
Expenditure allowed in draft report	259	254	234	256	265
Adjustment due to MMA growth forecasts	-9	20	16	15	12
Adjustment for pre DM basis	8	16	16	4	-22
Adjustment for security fencing	13	13	13	13	-
Other	14	1	3	3	3
Total expenditure allowed	**285**	**304**	**282**	**291**	**258**

48 The Tribunal's demand management draft decision required that these projections exclude the impact of any demand management projects expected to occur during the 2004-09 regulatory period. The Tribunal believes this approach is appropriate, so that DNSPs retain the benefit of demand management-induced costs savings during the 2004-09 regulatory period (see Chapter 8). This is consistent with the treatment of these costs by the other DNSPs.

The Tribunal did not allow Integral Energy's proposed expenditure relating to the GCSS and MSATS Procedure. It believes that due to the level of uncertainty associated with these expenditures, they are best provided for via the cost pass through mechanism (see Chapter 11).

Country Energy

Country Energy's medium growth rates (on which it based the projected expenditures provided in its 2003 submission) are the same as the MMA growth rates the Tribunal used for this determination, so no adjustments to reflect these forecasts are required. However, after the draft report was released, Country Energy submitted that it would require additional capital expenditure for the following purposes:

- **Sub-transmission works.** It proposed to spend $75m to advance its planned sub-transmission works over the regulatory period, to alleviate emerging constraints in its network. It did not include this expenditure in its 2003 submission because it believed it would not have the resources (or be able to contract them) to undertake the work. It now considers it will be able to do this work by using external contractors.
- **Substation security.** It proposed to spend $13m pa for four years on upgrading security at 120 substations in major urban centres, based on an estimated $100,000 per substation.
- **GCSS.** It projected it would need an additional $6m to implement the changes to the GCSS proposed in the Tribunal's draft report to the Minister.

Wilson Cook reviewed its projected expenditure for sub-transmission works and substation security. It concluded that the additional expenditure on sub-transmission works is not reasonable and efficient due to:

- A lack of definition in the expenditures needed to match load growth in the high-growth areas referred to.
- A lack of new information or circumstances, other than the relief of resource constraints, to warrant the work. As new factors did not appear to be the driver of the further investment requested, Wilson Cook presumed that the most important works were (or should have been) prioritised and allowed for adequately in Country Energy's original capital expenditure projections.
- Reservations about the extent to which resource constraints have actually been relieved and the speed with which the DNSP could gear up for, and implement the increased levels of construction work entailed. [49]

Wilson Cook found that the proposed additional expenditure on substation security is reasonable and efficient.

Based on its own analysis, plus its consideration of Wilson Cook's findings and stakeholder submissions, the Tribunal decided to allow the projected capital expenditure for Country Energy shown in Table 4.6. Table 4.13 shows how this amount was derived.

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49 Wilson Cook & Co Ltd, *Review of Revised Operating and Capital Expenditure of DNSPs*, April 2004.

Table 4.13 Country Energy's allowed projected capital expenditure 2004/05 to 2008/09 (millions, nominal)

	2004/05	2005/06	2006/07	2007/08	2008/09
Expenditure allowed in draft report	237	242	245	255	261
Adjustment due to MMA growth forecasts	-	-	-	-	-
Adjustment for security fencing	2	2	3	3	3
Other	1	1	-	-	-
Total expenditure allowed	240	245	248	257	264

Totals may not add due to rounding.

Based on the recommendations of its consultant and its own analysis the Tribunal did not allow Country Energy's proposed expenditure for sub-transmission works. It did not allow proposed expenditure related to the GCSS because found that, due to the level of uncertainty associated with these expenditures, they are best provided for via the cost pass through mechanism (see Chapter 11).

Australian Inland

After the draft report was released, Australian Inland submitted that it would need the following additional capital expenditure:

- $3m associated with reliability and growth
- $1m over five years for upgrading of security fencing around substations.

Wilson Cook reviewed these expenditures and concluded that only an additional $1m for growth and reliability, plus $1m for security fencing would be reasonable and efficient.

In addition, Australian Inland estimated it would need an additional $1m in capital expenditure to implement any changes to the GCSS recommended by the Tribunal, and proposed that this expenditure should be dealt with via a cost pass through mechanism.

Based on its own analysis, and its consideration of Wilson Cook's findings and stakeholder submissions, the Tribunal decided to allow the projected capital expenditure for Australian Inland shown in Table 4.6. Table 4.14 shows how this amount was derived.

Table 4.14 Australian Inland's forecast capital expenditures 2004/05 to 2008/09

	2004/05	2005/06	2006/07	2007/08	2008/09
Expenditure allowed in draft report	3	3	3	3	3
Adjustment for growth and reliability	0.5	0.5	0	0	0
Adjustment for security fencing	0.3	0.3	0.3	0.3	-
Other	1	-	-	-	-
Total expenditure allowed	**5**	**4**	**3**	**3**	**3**

Columns may not add due to rounding.

4.4 Final decisions on efficient operating and maintenance expenditure for 2004/05 to 2008/09

The Tribunal has decided the operating and maintenance expenditure shown in Table 4.15 is efficient. It therefore included an allowance for this expenditure when calculating each DNSP's notional annual revenue requirements.

Table 4.15 Projected operating and maintenance expenditures used in notional revenue requirements ($million, nominal)

	2005	2006	2007	2008	2009
EnergyAustralia	288	303	312	319	326
Integral Energy	208	214	221	229	236
Country Energy	223	231	240	249	259
Australian Inland	10	10	10	10	11

In making this final decision, the Tribunal has:

- Allowed EA's medium growth operating expenditure plus additional operating expenditure associated with MMA growth forecasts of $5m plus an additional $4m pa for self insurance plus the additional $4m per annum in recognition that the reduction in capital expenditure implies an increased need in operating expenditures.
- Allowed Integral Energy's proposed operating and maintenance expenditure under MMA's growth scenario, and allowed an additional amount of $5m per annum in recognition that the reduction in capital expenditure implies an increased need in operating expenditures. In addition, operating expenditure of $0.5m per annum associated with security fencing has been allowed.
- Allowed Country Energy's proposed operating and maintenance expenditure under the MMA growth scenario.
- Allowed Australian Inland's proposed operating and maintenance expenditure under the MMA growth scenario.

It should be noted that in the draft determination, $72m was accidentally omitted from Country Energy's allowance for operating expenditure. This expenditure was found to be efficient by Meritec and approved by the Tribunal for inclusion in the draft determination. It has therefore been included in Country Energy's allowance for projected operating and maintenance expenditure shown above.

4.4.1 Summary of draft decision on efficient operating and maintenance expenditure and stakeholder responses

In its draft determination, the Tribunal:

- Allowed all DNSPs' proposed operational and maintenance expenditure under their medium growth scenario.
- Made an allowance of $4m and $5m per annum for EnergyAustralia and Integral Energy respectively, in recognition that its decision to allow these DNSPs less capital expenditure than they proposed implies an increased need in operating expenditures.

The Tribunal received a range of responses from stakeholders on these draft decisions:

- The Energy Users Association of Australia argued that the Tribunal's allowances for operating expenditure were too high, and suggested that it should allow only $3.2 billion, or $0.7 billion less than the DNSPs proposed.
- Country Energy pointed out that while the Tribunal had accepted Mertiec's finding that its proposed operating expenditure were efficient, it did not include $72m of this expenditure.
- EnergyAustralia pointed out that in its April 2003 submission it had implicitly assumed that real hourly wage rates and the real cost of installing capital equipment will not increase over the life of the determination. It submitted that real wages are increasing at a higher rate than inflation, and that the Tribunal must therefore make an upward adjustment for this.

4.4.2 DNSPs' revised projected operating and maintenance expenditures

In response to the draft report, the DNSPs submitted additional projected operating expenditures to the Tribunal, as shown in Table 4.16. All the DNSPs indicated that since preparing the operating expenditure forecasts they submitted to the Tribunal in April 2003, events have occurred or are likely to be incurred that impose significant additional costs on them:

- EnergyAustralia submitted that costs associated with possible changes to Occupational Health and Safety (OH&S) obligations regarding live line working, and changes to the demarcation between customer and DNSP assets (the connection point) contained in the Electricity Supply Act should be included in its operating expenditures. However, Integral Energy and Country Energy proposed that these costs be dealt with via a cost pass through mechanism.
- EnergyAustralia also submitted that an additional amount for self insurance costs of $4 million per annum be included in its operating expenditures. It commissioned Deloittes to do an actuarial review of its self insurance costs. It included an allowance of $2 million per annum in the projected operating expenditure in its 2003 submission, based on Deloittes' preliminary recommendation. However, Deloittes has since provided its final report, which recommends an allowance of $6 million per annum.

Table 4.16 DNSPs' additional operating expenditures ($million, nominal)

	Energy Australia	Integral Energy	Country Energy	Australian Inland
Growth related	5	-	-	-
Live line	119	73	78	8
Security fencing	-	2	-	-
GCSS	40	3	35	-
Interval meters	-	1	-	-
Changes to Electricity Supply Act re connection point	33	27	-	-
Self insurance	20	-	-	-
Total	**217**	**106**	**113**	**8**

Source: DNSPs submission to Wilson Cook.
Totals may not add due to rounding.

The Tribunal commissioned Wilson Cook to review these proposed additional operating and maintenance expenditures.

4.4.3 Tribunal's considerations in making final decisions on efficient operating and maintenance expenditure

In making its final decisions on efficient operating and maintenance expenditures, the Tribunal considered the findings of its consultants, and all stakeholder submissions on this issue.

It decided to allow Integral Energy's proposed additional expenditure for upgrading of substation security fencing, as Wilson Cook found that this expenditure was reasonable and efficient.

It also decided to allow EnergyAustralia's proposed additional expenditure for self insurance, for the following reasons:

- Meritec's review of the $2 million per annum allowance for this purpose included in EnergyAustralia's 2003 submission found that it is reasonable and efficient.
- The additional expenditure arises almost entirely from changes in the actuarial assessment of provisions needed for EnergyAustralia's defined benefits superannuation scheme.

However, it decided not to allow the DNSPs' proposed additional expenditures associated with possible changes to live line workings, the Electricity Supply Act, mandatory roll-out of interval meters, and the GCSS. In relation to live line workings, the Tribubal accepted Wilson Cook's finding that there is no:

> … clear link between the prospective changes and the industry's safety performance [which] suggests that the changes are driven by external factors unrelated to electricity supply industry safety. Thus we do not consider the expenditures are reasonable or efficient for DNSPs to undertake. The DNSPs would appear to have little choice other than to incur additional expenditures if the changes are promulgated. Additional costs should be reviewed later, when more information is available. [50]

It also found that there is considerable uncertainly about:

- When and if changes will be made to the Electricity Supply Act and regulations regarding the definition of the point of connection. Only EnergyAustralia and Integral Energy provided an estimate for this.
- Whether the government is likely to announce a mandatory implementation of interval meters.
- Any possible changes to the GCSS.

The Tribunal agrees with Wilson Cook's assessment. Accordingly, the Tribunal has decided that given the uncertainty associated with these events, no allowance be made in the building blocks. If any of these events occurs, then the efficient and incremental costs associated with the event should be handled via a cost pass through mechanism (see Chapter 11).

In relation to EnergyAustralia's request that an adjustment be made to its operating expenditure projections to reflect the fact that the real wage rate and construction costs have increased by more than inflation, the Tribunal decided not to allow this adjustment. It considers that EnergyAustralia should have been able to adequately forecast wage movements prior to submitting its April 2003 submission. In addition, EnergyAustralia did not submit this proposed change to Wilson Cook, so this expenditure has not been reviewed for efficiency.

50 Wilson Cook & Co Ltd, *Review of Revised Operating and Capital Expenditure of DNSPs*, April 2004, p 14.

5 ESTABLISHING THE REGULATORY ASSET BASE

A DNSP's regulatory asset base (RAB), which is a measure of the financial value invested in it by its owner, has a substantial impact on distribution prices through its links to the allowances in the cost building blocks for the return on capital and return of capital (depreciation). As part of its determination, the Tribunal has determined an approach for establishing the opening value for each DNSP's RAB at 1 July 2003, and a methodology for rolling this value forward to 2008/09. It has used this approach and methodology to determine the building block allowances for depreciation and rate of return.

The Tribunal has taken a financial view of the RAB, which means that once struck, its value is effectively detached from the underlying physical assets. This financial view means that, in providing for a return of and on the RAB over the 2004-09 regulatory period, the Tribunal has sought to maintain the owner's financial investment in real terms. This approach is consistent with the approach it took in the 1999 determination, and has taken in price determinations for water and gas utilities.

This chapter sets out the Tribunal's final decisions and the resulting value for each DNSP's RAB. It also discusses the issues raised by stakeholders in response to the Tribunal's draft decisions on the RAB, the Tribunal's consideration of these issues in making its final decisions, and its treatment of investments during the 2004-09 regulatory period.

5.1 Final decisions

The Tribunal has affirmed its draft decision that it will establish the opening regulatory asset base for the 2004-09 regulatory period by:

- **rolling forward the 1998 RAB to 30 June 2003 on the basis of actual prudent capital expenditure**
- **rolling forward the RAB at 30 June 2003 to 30 June 2004 on the basis of the forecast capital expenditure allowed by the Tribunal in this final determination.**

The opening RAB at 1 July 2003 will be calculated by:

- **indexing the initial 30 June 1998 RAB[51] for actual CPI**
- **adding actual prudent capital expenditure to 30 June 2003**
- **deducting regulatory depreciation as allowed for in the Tribunal's 1999 determination[52] and depreciation on allowed full retail contestability (FRC) costs, indexed for actual inflation**
- **deducting actual disposals.**

The Tribunal has also affirmed its draft decision that it will not allow:

- **adjustments to the 1998 RAB as part of the roll forward methodology**
- **ex-post recovery of the foregone return on capital (holding costs) on unanticipated capital expenditure during the 1999-04 regulatory period (the capital overspend)**

51 As specified in Table 6.1 of the Tribunal's 1999 Determination, *Regulation of New South Wales Electricity Distribution Networks*, NCDet99-1, December 1999, p 49.

52 Ibid, p 61.

- **adjustments to the RAB as a result of changes in the taxation arrangements for contributed assets.**

The opening RAB for each DNSP is shown in Table 5.1.

Table 5.1 Opening regulatory asset bases for 2004-09 regulatory period as at 1 July 2004 (nominal values)

DNSP	*Opening asset base $m*
EnergyAustralia	4,116
Integral Energy	2,283
Country Energy	2,375
Australian Inland	65
Total	8,839

5.2 Summary of responses to draft decisions

The Tribunal's final decisions on the approach and methodology for calculating the DNSPs' regulatory asset bases are the same as its draft decisions, set out in the Draft Report on electricity distribution pricing.[53] Several stakeholders responded to these draft decisions. In general, most supported the Tribunal's approach and methodology for calculating the opening RAB for the 2004-09 regulatory period. In particular, the DNSPs supported the use of a roll-forward approach and the decision to deduct the allowed regulatory depreciation rather than actual depreciation of incurred expenditure when calculating the opening RAB at 1 July 2003. As discussed below, Origin Energy raised concerns about the treatment of indexation in the roll forward methodology.[54]

However, EnergyAustralia, Integral Energy and Country Energy disagreed with the Tribunal's draft decision not to allow adjustments to the 1998 RAB as part of the roll-forward. In their submissions, the DNSPs re-stated their views and arguments for adjusting the 1998 RAB and asked the Tribunal to re-consider its decision on this issue. The Energy Markets Reform Forum (EMRF) disagreed with the draft decision not to undertake an Optimised Deprival Valuation (ODV) of each DNSP's pre-1999 assets.[55]

EnergyAustralia also disagreed with the draft decision not to allow recovery of the foregone return on the unanticipated capital expenditure incurred during the 1999-04 regulatory period.[56] In addition, it asked the Tribunal to provide details of the regulatory test that would be applied to investments made during the 1999-2004 regulatory period for inclusion in the 2004 regulatory asset base.[57]

53 IPART, *NSW Electricity Distribution Pricing 2004/05 to 2008/09 - Draft Report*, OP-18, January 2004.
54 Origin Energy submission to the Draft Report, March 2004, p 3.
55 EMRF submission to the Draft Report, March 2004, p 2.
56 EnergyAustralia submission to the Draft Report, March 2004, p 28.
57 Ibid, p 28.

5.3 Tribunal's considerations in making its final decisions

In making its final decisions on the regulatory asset base, the Tribunal has carefully considered all stakeholder views, and the principles and objectives of the Code. Its considerations in relation to each of these decisions are explained below.

The opening RAB will be established by rolling forward the 1998 RAB

The Tribunal has decided to establish the opening RAB for the 2004-09 regulatory period using a roll-forward approach, rather than undertaking a Depreciated Optimised Replacement Cost (DORC) based revaluation. The DNSPs supported the Tribunal's draft decision on this issue. In addition, the Tribunal is of the view that the roll-forward approach provides a greater degree of certainty for the DNSPs. For example, periodic revaluations reduce certainty because under this approach, asset values vary with changes in unit values for assets and depend partly on the judgement of the valuer over such things as appropriate unit value levels and asset optimisation. The roll-forward approach increases certainty by diminishing the possibility of regulatory opportunism. [58]

For the purposes of the financial modelling that supports the calculation of the X-factors, the RAB has been rolled forward in the following manner:

- the opening capital base at the start of each year [59] was indexed by the CPI at the end of the year
- projected capital expenditure (excluding capital contributions) was added
- half the capital expenditure is assumed to occur at the start of the year and was indexed by the CPI, the remaining half is assumed to occur at the end of the year and is not indexed
- projected disposals were deducted
- regulatory depreciation was deducted to yield the closing balance for the year, which becomes the next year's opening balance.

Origin Energy raised a concern about this roll-forward methodology. It submitted that indexing the opening capital base and half the capital expenditure by the CPI while also including CPI adjustments in the Weighted Average Cost of Capital (WACC) that is used to calculate the allowance for the return on capital (see Chapter 6) means that the effect of CPI is double counted.[60] The Tribunal believes this concern may arise from a misconception about how the allowance for the return on capital is calculated. The Tribunal applies a real, pre-tax rate of return, which *excludes* any compensation for the loss in purchasing power due to the effect of general price increases in the economy (as measured by the CPI). For this reason, it is appropriate that the regulatory asset base is indexed to maintain the value of the shareholders' investment in real terms.

58 The Tribunal has previously expressed doubts about whether a DORC valuation is an appropriate basis for determining the regulatory asset base for a regulated network business. For example see IPART, *Pricing for Electricity Networks and Retail Supply, Volume 1,* Rev99-5.1, June 1999, p 67.

59 Net of half of projected disposals in that year. This reflects the fact that disposals occur throughout the year so that on average disposals occur halfway through the year.

60 Origin Energy submission, March 2004, p 3.

5.3.1 No adjustments to the 1998 RAB will be allowed

The Tribunal has decided that no adjustments to the 1998 RAB will be allowed, and pre-1999 assets will not be subject to an Optimised Deprival Value (ODV) revaluation. It reconsidered the arguments put forward by Country Energy, Integral Energy and the EMRF. However, it believes that its reasons for making these decisions remain valid, and that the decisions are consistent with the principles and objectives of the Code. These reasons are summarised below—for a more detailed explanation, see Chapter 4 and Appendix 6 of the Draft Report.[61]

Country Energy's and Integral Energy's arguments for adjusting their 1998 RAB are based on their view that their 1998 DORC valuations were flawed. This argument presumes that adjustments to a DNSP's DORC valuation will automatically be reflected in its regulatory asset value. However, the Tribunal considers this presumption to be unreasonable. Although the 1999 determination aligned most DNSPs' 1998 RAB values with the 1998 DORC valuation of their assets, the Tribunal clearly indicated in that determination (and several others) that it has serious reservations about using the DORC valuation to establish the RAB, and that this valuation should be only one of a range of factors considered when establishing the RAB.

Further, some DNSPs suggested that the ACCC's decision to allow adjustments to transmission network service providers' RABs creates a relevant regulatory precedent. But the Tribunal does not accept this, given that the ACCC made its decision under a regulatory framework that includes (draft) regulatory principles that explicitly recognise a DORC valuation of the regulatory asset base.

Although the Tribunal has not used the ODV approach, it believes this approach provides further support for its view that the presumption that adjustments in the DORC value will be automatically reflected in the RAB value is unreasonable. Under this approach, the value of a DNSP's assets is calculated as the DORC value or the economic value of these assets, whichever is lower. Therefore, where the economic value is less than the DORC value, changes to the DORC value would not necessarily affect the regulatory asset value. As the New Zealand Ministry of Economic Development has noted, this is most likely to be the case for distributors with networks in rural areas, with remote, lengthy lines—such as Country Energy and Australian Inland.[62]

In addition, at the time the 1998 RAB was established, the pre-existing policy of the NSW Government was that asset values for rural distributors be restrained to avoid real price increases in network changes. As a result, the Tribunal established a regulatory asset value for Australian Inland that was significantly less than the DORC value to avoid real network price increases. The Tribunal considers that if the adjustments that Country Energy now proposes had been made to its 1998 DORC value at that time, they would not necessarily have resulted in a higher 1998 RAB for the same reason.

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61 IPART, *NSW Electricity Distribution Pricing 2004/05 to 2008/09, Draft Report*, OP-18, January 2004, pp 43-48 and pp 195-210.

62 New Zealand Ministry of Economic Development, *Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Line Businesses*, Third Edition, April 1999, p 13.

The Tribunal is also of the view that, given that Country Energy's and Integral Energy's investment in the assets in question is sunk, allowing their proposed adjustments to their 1998 RABs would effectively result in a financial transfer from customers to the DNSPs' owner, with a significant cost to regulatory certainty and economic efficiency and little benefit. In particular:

- If the Tribunal were to allow adjustments in principle, it would need to re-value the 1998 RAB for *all* DNSPs, to ensure that the process to determine these adjustments is fair and transparent and takes into account all issues that may lead to adjustments (both upward and downward). This would be inconsistent with its preferred roll-forward approach, and would increase the level of regulatory risk for DNSPs.
- If Country Energy's and Integral Energy's proposed adjustments were allowed, they would result in significant increases to these DNSPs' 2004 RABs. When these increases are translated to prices, they are likely to have adverse consequences for allocative efficiency and competition, by increasing the gap between economically efficient marginal cost price and the regulated average price.
- In addition, these increases would provide few benefits in terms of dynamic efficiency (that is, incentives for investment), since the assets in question formed part of the DNSPs' sunk pre-1999 assets. Further, the businesses retain the incentive to maintain and replace these assets, as the Tribunal allows efficient maintenance and replacement expenditure for these assets in the cost building blocks.

The Tribunal strongly rejects Integral Energy's and Country Energy's suggestion that by failing to allow their proposed adjustments to the 1998 RAB, it is breaching the underlying regulatory contract, to the detriment of incentives for investment. The Tribunal does not consider that the 1999 determination created an expectation among DNSPs or other stakeholders that the DNSPs' RABs would be adjusted if inaccuracies were identified in the 1998 DORC valuation. On the contrary, it believes that its past processes and decisions clearly signal that, in considering proposals to amend the 1998 RAB, it would take account of a range of factors, not only revisions to the 1998 DORC valuation.

The Tribunal also rejects Country Energy's argument that the Tribunal's decision magnifies uncertainty and risk,[63] and could adversely affect its ability to fund the further replacement of the assets in question.[64] The Tribunal notes that its determination leaves Country Energy in a sound financial position, achieving an overall NSW Treasury rating of A (see Chapter 7). The Tribunal also notes that future prices would need to reflect the future replacement costs of the assets in question to ensure that Country Energy retains an incentive to maintain these assets.

5.3.2 No ex-post recovery of the foregone return on capital overspend will be allowed

All the DNSPs except Australian Inland incurred higher actual capital and operating expenditure than provided for in the 1999 determination. As discussed in Chapter 4, Meritec reviewed each DNSP's capital expenditure during the 1999 regulatory period, and found that all this expenditure was prudent. The Tribunal agrees with this finding. It has decided to roll forward the regulatory asset base on the basis of prudent capital expenditure.

63 Country Energy submission to the Draft Report, 5 March 2004, p 50.

64 Country Energy submission to the Draft Report, 5 March 2004.

In principle, if this expenditure had been fully anticipated at the time of the 1999 determination, the DNSPs would have received higher allowances for regulatory depreciation and a return on capital for this expenditure. The Tribunal has considered whether the DNSPs should be compensated for this foregone depreciation and return on capital. It has decided that:

- the capital overspend will be rolled into the regulatory asset base at its undepreciated value — that is, DNSPs will be allowed to recoup the depreciation on this overspend from future customers
- however, there will be no ex-post recovery of the foregone return on capital for the capital overspend.

Practically, this final decision means that regulatory depreciation rather than actual depreciation will be deducted when rolling forward the regulatory asset base.

To achieve regulatory consistency, the Tribunal will also not allow ex-post recovery of operating expenditure incurred above that allowed in the 1999 determination. In addition, it is of the view that a symmetrical approach should apply when a DNSP spends less capital and operating expenditure than allowed for in the determination in future regulatory periods. Specifically, this means:

- the DNSP would be allowed to retain the return on capital on the difference between allowed and actual (prudent) capital expenditure
- regulatory depreciation would be used to roll forward the regulatory asset base so that the regulatory asset base will be written down more than if actual depreciation were used
- the DNSP would be allowed to retain the difference between allowed and actual operating expenditure.

In response to the Tribunal's draft decision, EnergyAustralia submitted:

> It is obvious, therefore, that IPART has created a regime that does not provide incentives to invest in prudent and efficient expenditure once the annual expenditure 'cap' is reached. Rather, IPART has established a framework whereby the only relevant fact is how accurate the original forecast was with little regard to actual circumstances at the time of the investment.[65]

The Tribunal considers that EnergyAustralia's contention is at odds with the principles of incentive-based regulation. The CPI-X form of regulation fixes the regulatory parameters (in this case, the X-factors) that determine the revenues that might be earned by DNSPs for the regulatory period. This provides the DNSPs with an incentive to pursue both capital and operating cost efficiencies, by allowing them to retain the benefits of cost savings until the next price reset rather than immediately passing cost savings directly on to customers through lower prices. Similarly, when costs are unexpectedly higher, DNSPs retain the incentive to minimise these costs overruns to reduce the adverse impacts on profits. The incentive-based regime does mean that DNSPs face increased financial risk as a result of the fixed regulatory parameters. However, this is one of the main reasons that they are allowed to earn a regulated rate of return that is higher than the risk-free rate.

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65 EnergyAustralia submission, March 2004, p 28.

In contrast to EnergyAustralia's claim, under an incentive-based regime, the incentive not to invest in prudent and efficient expenditure is present regardless of whether the annual expenditure cap it reached or not. This is a fundamental feature of incentive regulation, and highlights the importance of the regulator monitoring standards of service to ensure that cost savings are not achieved at the expense of service quality. The Tribunal is of the view that allowing ex-post recovery of the foregone return on capital overspend, as EnergyAustralia proposed, would mean that the regulatory framework is very close to a cost-plus regulatory regime — which gives strong incentives to *spend* regardless of efficiency — rather than the incentive-based regulatory regime as required by the Code.

The Tribunal is of the view that its final decision achieves a balance between maintaining the incentives in the regulatory framework for DNSPs to pursue capital and operating cost efficiencies and the need to ensure that DNSPs are not unduly disadvantaged for undertaking unforeseen prudent expenditure.

5.3.3 No adjustments to the RAB to reflect changes in taxation arrangements will be allowed

The Tribunal has decided that it will not provide an allowance in the regulatory asset base for net present value of losses associated with changes in the income tax provisions for contributed assets. From 1 July 2001, the NSW DNSPs came under the National Taxation Equivalent Regime (NTER), which requires them to pay corporate tax on contributed assets. When they were under the NSW Taxation Equivalent Regime, capital contributions were exempt from tax equivalent payments.

EnergyAustralia argued that this change adversely affects its business, due to timing differences between the tax paid on the capital contribution and the benefits of the tax shield derived from the depreciation of the contributed asset for tax purposes. It proposed that the Tribunal recognise the tax it pays on capital contributions as capital expenditure on the assets, and so include this expenditure in its regulatory asset base.[66]

The Tribunal considered this proposal in making its draft decision, but decided not to allow adjustments to the RAB due to changes in tax provisions for contributed assets. In establishing the WACC on the basis of the statutory tax rate rather than an effective tax rate (see Chapter 6), the Tribunal has elected not to involve itself in the DNSPs' tax affairs. It therefore considers that using a statutory tax rate rather than an effective tax rate in the derivation of the WACC provides sufficient compensation to DNSPs for the timing difference identified by EnergyAustralia. It also notes that taxation timing differences (such as those resulting from different depreciation rates, accrual and payment of service leave) are a common occurrence, and sometimes work in the DNSPs' favour.

No stakeholders responded to this draft decision.

66 EnergyAustralia submission, 10 April 2003, p 55-56.

5.4 Clarification of the treatment of investments made in 2004-09 regulatory period

EnergyAustralia submitted that the Tribunal is obliged to ensure that it clearly articulates the manner in which it intends to assess capital expenditure prior to these investments taking place. It also noted that it had 'made repeated calls for IPART to provide guidance as to the test that will be applied to investments during the regulatory period for inclusion in the RAB' and 'to date details of the tests and how they would be applied have not been forthcoming'.[67]

In the lead up to the present review, the Tribunal held a public forum on 'Prudent Expenditure on Network and Non-Network Alternatives',[68] which was intended to facilitate an open discussion on prudent investment processes and also to hear stakeholders' views on how the Tribunal should assess capital expenditure as part of this review. It then wrote to the DNSPs,[69] providing guidance on the prudency test that would be applied as part of the total cost review for the 2004-09 determination.

The Tribunal is of the view that this letter, together with the precedents set in the cost reviews it has undertaken as part of this and other price reviews, provide a strong guide to DNSPs on its approach to and process for assessing the prudency of investment in the future. It notes that there will always be some uncertainty about what future regulators may decide, as the current Tribunal cannot make decisions that legally bind future members or other regulators to any course of action. But it does not agree with EnergyAustralia's claim that the process for assessing prudency is unclear.

EnergyAustralia also proposed that the Tribunal deem prudent all projects that EnergyAustralia could demonstrate were subject to its own governance process.[70] It argued that this approach would provide it with a greater degree of regulatory certainty. However, the Tribunal does not believe such an approach would deliver this benefit. As noted above, it cannot make decisions that legally bind future regulators. This means that while the current determination could deem any project that has been developed in accordance with a DNSP's capital governance policy as prudent, there would be no legal obligation on future regulators to accept this judgement. Therefore, some regulatory uncertainty would still exist.

In addition, the Tribunal has several fundamental concerns about the proposed approach. First, there would be asymmetry of information in terms of the process. EnergyAustralia's proposal relies on the Tribunal having confidence in the DNSP's process, and that this process is being implemented correctly. It could obtain some information on the latter by reviewing the audit trail to check whether the various steps in the capital governance process were taken. However, this would not reveal whether the decision-making process had considered a full range of available alternatives to the project — for example, were there any non-network or other solutions that could have met project objectives at a lower cost?

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67 EnergyAustralia submission to the Draft Report, March 2004.

68 2 April 2001. See the Tribunal's website for details: www.ipart.nsw.gov.au/papers/agenda020401.html.

69 23 November 2001. See the Tribunal's website at www.ipart.nsw.gov.au/papers/Prudency.pdf.

70 EnergyAustralia submission, 10 April 2003, p 60.

Second, this asymmetry of information could be overcome by examining a sample of projects in detail, but the resulting process would be very similar to the process Meritec followed in the total cost review. (Meritec was asked to examine each DNSP's process for approving capital expenditure, and look at a number of projects in detail.) Therefore, the proposed approach is not likely to deliver the significant improvements in certainty that EnergyAustralia is seeking.

Third, under EA's proposed approach, once a project has been approved under the DNSPs' governance process, there would seem little scope for the Tribunal to disallow any expenditure associated with inefficient cost over-runs. This would seem to weaken the incentives for DNSPs to minimise cost over-runs on projects. As an alternative, the Tribunal could allow only the value that was approved under the capital governance process to be rolled in to the asset base. However, this would disadvantage DNSPs where unexpected over-runs are unavoidable and prudent. It would also create an incentive to overstate project costs during the approval process.

Finally, the Tribunal is concerned that EnergyAustralia's proposed approach removes the scope for stranding assets. Although it is guided by its financial view of the regulatory asset base, the Tribunal believes that it is important that it retains the right to strand assets in limited circumstances. This right provides a mechanism for pragmatically handling situations where it would not be 'fair' to ask customers to bear the cost of an unused asset, or where attempts to recover the full cost of an asset may price the DNSP out of the market.

6 ESTABLISHING THE COST BUILDING BLOCKS

When the Tribunal has determined appropriate growth forecasts, total costs levels and regulatory asset base values for each DNSP (see Chapters 4 and 5), the next step is to establish the cost building blocks for each DNSP. The cost building blocks represent:

- a forecast of the DNSP's efficient operating and maintenance expenditure over the regulatory period
- an allowance for a return on assets over this period
- an allowance for a return of capital (depreciation)
- an allowance for the cost of working capital.

The Tribunal then adds these costs blocks together, and adjusts the resulting amount to account for the closing balance of the unders and overs account from the 1999 regulatory period. This process determines the notional revenue requirements for each DNSP for each year of the regulatory period.

This chapter explains the Tribunal's final decisions in relation to each of the cost building blocks and the DNSPs' closing unders and overs account balances at 30 June 2004, and sets out the resulting notional annual revenue requirements.

In determining each of the building block components the Tribunal has adopted a financial view of the regulatory asset base. This financial view means that, on a forward looking basis, in providing a return on and of capital, the Tribunal seeks to maintain shareholder's financial investment in real terms. However, as discussed in chapter 7 the Tribunal is also required under the Code to have regard to a wide range of matters including public interest and price stability. **So, while the Tribunal determines individual building blocks based on a financial view, it then takes into account and balances other matters it is to have regard to under the Code to determine an appropriate price path.**

6.1 Efficient operating and maintenance expenditure for 2004/05 to 2008/09

The Tribunal has decided the operating and maintenance expenditure shown in Table 6.1 is efficient. It therefore included an allowance for this expenditure when calculating each DNSP's notional annual revenue requirements.

Table 6.1 Projected operating and maintenance expenditures used in notional revenue requirements ($million, nominal)

	2005	2006	2007	2008	2009
EnergyAustralia	288	303	312	319	326
Integral Energy	208	214	221	229	236
Country Energy	222	231	240	249	259
Australian Inland	10	10	10	10	11

This chapter discusses the Tribunal's analysis and considerations in making these decisions in detail. However, in summary, the Tribunal has:

- Allowed EnergyAustralia's medium growth operating expenditure plus additional operating expenditure associated with MMA growth forecasts of $5m plus and additional $4m pa for self insurance plus the additional $4m per annum in recognition that the reduction in capital expenditure implies an increased need in operating expenditures.
- Allowed Integral Energy's proposed operating and maintenance expenditure under MMA growth scenario, and allowed an additional amount of $5m per annum in recognition that the reduction in capital expenditure implies an increased need in operating expenditures. In addition, operating expenditure of $0.5m per annum associated with security fencing has been allowed.
- Allowed Country Energy's proposed operating and maintenance expenditure under a MMA growth scenario.
- Allowed Australian Inland's proposed operating and maintenance expenditure under a MMA growth scenario.

6.2 Allowance for a return on capital

Within the building block methodology, the allowance for a return on capital covers the opportunity cost of capital invested in the DNSP by its owner. This allowance typically represents around 30 to 40 per cent of the DNSP's notional annual revenue requirement. It therefore has a significant impact on distribution prices and the financial outcomes for the DNSP and its customers.

The Tribunal calculates each DNSP's allowance for a return on capital by multiplying the value of the DNSP's regulatory asset base[71] by an appropriate rate of return. To determine what rate of return is appropriate, the Tribunal considers the DNSPs' and other stakeholders' submissions on this issue, and calculates a range for the weighted average cost of capital (WACC). It then makes a judgement on what rate of return within this WACC range is appropriate, given the competing objectives in the Code.[72] In particular, it aims to achieve an appropriate balance between the interests of customers and those of the DNSPs.

This section outlines the Tribunal's decision on the rate of return, summarises the stakeholder submissions and outlines its considerations in making the final rate of return decision. In addition, this section outlines key changes to the WACC parameters since the draft determination, which influenced the final WACC range outcome. Its decisions in relation to the rate of return and the resulting allowances for a return on capital, plus a summary of responses to its draft decision and its considerations in making its final decisions are set out below.

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71 For information on the Tribunal's decision on the regulatory asset base for each DNSP, see chapter 5.

72 The Tribunal as the jurisdictional regulator applying the Code, has discretion to choose a rate of return within the WACC range which achieves in its view, an appropriate balance between the Code objectives.

6.2.1 Final decisions

The Tribunal decided that for the purpose of calculating the building block allowance for a return on capital, it will apply a real pre-tax rate of return of 7.0 per cent.

This decision was made with reference to the Tribunal's final finding on a WACC range of 6.1 to 7.5 per cent for the NSW DNSPs. In determining an appropriate rate of return within the WACC range, the Tribunal has considered the impacts on customers, businesses and shareholders to reach an appropriate balance.

Table 6.2 Return on capital building block components, 2004/05 to 2008/09 (nominal values)

DNSP	2004/05 $m	2005/06 $m	2006/07 $m	2007/08 $m	2008/09 $m
EnergyAustralia	295	318	340	362	384
Integral Energy	166	181	195	209	220
Country Energy	171	182	192	202	211
Australian Inland	5	5	5	5	5

6.2.2 Summary of stakeholder responses to draft decisions

In submissions received on the draft report a number of stakeholders raised concerns regarding the application of a real pre-tax rate of return of 6.8 per cent.

The submissions in general focused on concerns regarding the choice of WACC parameters in the draft determination, and a view that asymmetric risks[73] were not, but should be, reflected in the WACC.

The DNSPs argued that the draft determination rate of return was too low, and would have negative implications for the DNSPs and their owner. In particular:

- The DNSPs argued that it does not provide a risk adjusted cash flow rate of return comparable to that required by investors in commercial enterprises facing similar business risk to the DNSPs.
- NSW Treasury submitted that the rate of return is inadequate, and does not reflect the commercial return required by investors to invest in energy network infrastructure. It also argued that the margin of the real pre-tax rate of return over the real risk free rate does not provide the right incentives for efficient infrastructure investment. As the DNSPs' principal shareholder, it was concerned that the businesses earn a rate of return comparable to that of similar businesses in competitive markets.

Regarding an allowance for asymmetric risk, the DNSPs argued that this should be allowed through either a mechanism to pass through unforseen costs arising from these risks, or increase the WACC, to account for these costs.

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73 Asymmetric risks include regulatory risk, insurance, asset stranding, statutory changes, easements and risks arising form the introduction of the weighted average price cap.

Other stakeholders submitted that the draft rate of return was too high. In particular:

- The EMRF commented that the WACC is too high due to an excessively high market risk premium and equity beta.
- The Energy Users Association of Australia argued that the WACC is too high and it challenged the Tribunal to explain in a transparent way, why the Tribunal continues to base its parameter estimates on backward looking data sets rather than taking a forward looking approach similar to UK regulators.

6.2.3 Tribunal's considerations in making its final decisions

In making its final decisions, the Tribunal considered the arguments by the DNSPs, NSW Treasury, the Energy Networks Association and AGLGN that a 6.8 per cent pre-tax real rate of return is too low. It also considered the Energy Users Group's view that the pre-tax real rate of return of 6.8 percent is too high compared to UK utilities.

The Tribunal took the view that its key consideration when making its final decision on the rate of return for this determination should be to appropriately balance the interests of all stakeholders. It undertook further analysis on the rate of return, to compare the impact of different rates of return on customers' final nominal electricity bills, and on the DNSPs' financial position. This analysis indicated that:

- increasing the rate of return from 6.8 per cent to 7.0 per cent would have little impact on customers' final nominal bills, but would go some way, albeit modestly, towards addressing some of the DNSPs' concerns
- increasing the rate of return to 7.5 per cent, as requested by the DNSPs, would improve the DNSPs' financial position substantially, but would have a much more significant impact on customers' final bills.

Based on this analysis, it considers that the benefits to customers of maintaining the 6.8 per cent rate of return would not be sufficiently large to warrant a further deterioration in the DNSPs' financial position. However, increasing the rate of return to 7.5 per cent (or almost the top of the WACC range) would result in an unacceptable outcome for customers, particularly in light of the already substantial price increases being sought by the DNSPs. It therefore concluded that on balance, increasing the rate of return to 7.0 per cent is reasonable and justified.

An overview of its key considerations in relation to the WACC parameters it used and the allocation of asymmetric risk within the CAPM, and the implications of its decisions on the return on capital for key stakeholders is provided below. A full analysis of these decisions and a summary of submissions received on the return on capital can be found in Appendix 8.

The market risk premium is estimated to be in the range of 5.0 to 6.0 per cent

The Tribunal decided a market risk premium estimate of 5.0 to 6.0 per cent was appropriate. In reaching this decision, it considered arguments for both a lower and a higher estimate of the market risk premium (MRP).

Stakeholders who argued for a higher MRP did so on the grounds that the Tribunal should use historical studies only when estimating the MRP. Those who argued for a lower MRP cited a comprehensive study in which short-term historical estimates of the MRP were observed to be considerably lower than longer term estimates.[74]

The Tribunal accepts that shorter term estimates of the MRP may be lower than 5.0 to 6.0 per cent. However, given the uncertainty surrounding the input variables in these studies, the Tribunal found that these estimates might not accurately reflect what investors expect the market risk premium to be in the future.

Historical studies indicate that the value of the market risk premium lies somewhere between 4.8 and 8.1 per cent, depending on the estimation horizon used. The Tribunal is of the view that estimates of the MRP rely considerably on the underlying methodology used and the time period chosen. In the absence of new evidence and given the considerable uncertainty surrounding the existing estimates, it concluded that there is insufficient evidence to justify changing its current MRP range of 5.0 to 6.0 per cent.

The debt margin for investment grade credit rated debt is within a range of 90 to 110 basis points

The Tribunal decided to adopt a debt margin range of 90 to 110 basis points above the nominal risk free rate. In reaching this decision, it had regard to NSW Treasury's Government Guarantee Charge policy and yields on investment grade Australian bonds. It also noted that Treasury Corporation is currently charging Government-owned enterprises an interest differential based on US yields. In addition, it observed yields on investment grade bonds provided by CBASpectrum.[75] It concluded that a debt margin of 90 to 110 basis points is reasonable for investment grade rated debt with a benchmark maturity of 10 years.

An explicit allowance for debt raising and re-financing costs of 12.5 basis points is appropriate

The Tribunal decided to include an allowance of 12.5 basis points for debt raising and debt re-financing costs, on top of the debt margin. This brings the debt margin to a total of 102.5 to 122.5 basis points. This decision is based on the Tribunal's conclusion that debt raising and debt re-financing costs are costs above the debt margin that businesses incur in competitive markets.

The value of imputation tax credits (gamma) is 0.5

The Tribunal decided to adopt a gamma of 0.5. Some stakeholders argued that it should use a gamma range of 0.5 to 0.3 or 0, on the grounds that the studies the Tribunal relied on to make its draft decision are inconclusive on the real value of gamma. In addition, NSW Treasury submitted that market professionals use a gamma of zero and that the Tribunal should adopt this in its final decision.

In making its final decision, the Tribunal considered these arguments, and re-examined the available evidence. It found that there was no compelling evidence to support changing the value of gamma from 0.5.

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74 Headberry Partners P/L and Bob Lim & Co P/L., *Further capital markets evidence in relation to the market risk premium and equity beta values*, December 2003.

75 CBASpectrum produces yields on Australian bonds.

The debt beta value is estimated to fall within a range of 0 to 0.06

The Tribunal has adopted a debt beta range of 0 to 0.06. In reaching this decision, the Tribunal had regard to studies that indicate that the value of the debt beta is low but above zero. It notes that the evidence about the true value of the debt beta is inconclusive. The Tribunal believes that there is no compelling reason to change its approach from the draft decision.

The asset beta is estimated to fall within a range of 0.35 to 0.45

The Tribunal decided on an asset beta range of 0.35 to 0.45. In making this decision, the Tribunal analysed a number of beta values of comparable Australian businesses. It de-levered the equity beta of comparable Australian companies and re-levered them reflecting the benchmark capital structure of 60 per cent gearing using the Monkhouse formula. The asset betas derived in this analysis indicated that betas have fallen in recent times.

The Tribunal also considered the arguments of some stakeholders that it should use a lower asset beta. However, it found that there was no compelling evidence to suggest that a lower asset beta was more appropriate.

The equity beta is in a range of 0.78 to 1.11

The Tribunal applied the Monkhouse formula to derive the equity beta. This approach resulted in an equity beta range of 0.78 to 1.11.

No asymmetric risk has been allocated within the WACC

The Tribunal decided not to include any allowances for asymmetric risk in the WACC. It is of the view that these risks are diversifiable and therefore are not appropriately included in the CAPM.

The Tribunal also considered the DNSPs' argument that they face an increase in non-diversifiable risk relating to the introduction of the weighted average price cap. It found that there is not sufficient evidence to argue that these risks are non-diversifiable. It has therefore not accounted for them in the WACC under the CAPM model.

6.2.4 WACC calculation

The feasible WACC ranges of the draft and the final decisions have been calculated using the following parameters.

Table 6.3 WACC parameters

Parameter	Draft Decision	Final Decision
Nominal risk free rate	5.8%[76]	5.9%[77]
Inflation	2.3%	2.5%
Real risk free rate	3.5%[78]	3.3%[79]
Market risk premium	5.0-6.0	5.0-6.0
Debt margin	0.9%-1.1%	0.9%-1.1%
Allowance for debt raising costs	-	0.125%
Debt to total assets	60%	60%
Dividend imputation factor (gamma)	0.5	0.5
Tax rate	30%	30%
Asset beta	0.35-0.45	0.35-0.45
Debt beta	0.06-0	0.06-0
Equity beta	0.78-1.11	0.78-1.11
Cost of equity (nominal post-tax)	9.7%-12.5%	9.8-12.6%
Cost of debt (nominal pre-tax)	6.7-6.9%	6.9-7.1%
WACC (nominal post-tax)	6.0-7.0 %	6.1-7.1%
WACC (real pre-tax)	**6.2-7.6%**	**6.1-7.5%**

6.3 Allowance for return of capital (depreciation)

Within the building block methodology, the depreciation allowance represents the return of capital invested by the shareholder in a DNSP's business. It is an important cost building block, representing around 25 per cent of a DNSP's total notional revenue requirements.

The Code does not specify how the Tribunal should establish the allowance for depreciation. In the 1999 determination, it used a straight line depreciation profile, based on the asset lives established by the NSW Treasury's asset valuation study.[80] It also indicated that it would provide scope for alternative depreciation profiles to be used in the future, provided these can assist in managing market risks and variations in the prices of new investment. It required that proposed alternative depreciation profiles be net present value neutral compared with straight line depreciation.

76 20-day average of yields on 10-year Commonwealth Government bonds as at 19/11/2003.
77 20-day average of yields on 10-year Commonwealth Government bonds as at 06/05/2004.
78 20-day average of yields on 2010 and 2015 Treasury Indexed bonds as at 19/11/2003.
79 20-day average of yields on 2010 and 2015 Treasury Indexed bonds as at 06/05/2004.
80 NSW Treasury, *ODRC Valuation of Network Assets of NSW Network Businesses, Report on Standard and Effective Asset Lives*, February 1999.

The Tribunal's final decision on the method it will use to calculate the return of capital allowance in the notional revenue requirement for the determination, and the analysis that supports this decision, is summarised below.

6.3.1 Final decision

The Tribunal has decided that for the purpose of calculating the building block allowance for the return of capital (depreciation), it will use the straight line depreciation method.

For EnergyAustralia, it will use the asset lives proposed by EnergyAustralia, with the exception of the standard life for IT System categories. For the other DNSPs, it will use the asset lives applied in its 1999 determination.

The return of capital allowance included in the notional revenue requirements for each DNSP is shown in Table 6.4.

In addition, for Country Energy, the Tribunal has decided that it will allow the deferral of a proportion of this depreciation allowance. This decision is discussed in chapter 7.

Table 6.4 Return of capital building block components, 2004/05 to 2008/09 (nominal values)

DNSP	2004/05 $m	2005/06 $m	2006/07 $m	2007/08 $m	2008/09 $m
EnergyAustralia	170	187	205	223	243
Integral Energy	130	144	158	172	186
Country Energy	132	147	163	180	197
Australian Inland	3	3	4	4	4

Note: Values for Country Energy are before deferral of depreciation.

6.3.2 Summary of responses to draft decisions

The Tribunal's draft decisions in relation to the return of capital (depreciation) allowance was to use the straight line depreciation method and the asset lives proposed by the DNSP to calculate this allowance. Where the DNSP did not propose asset lives, it used the asset lives used in the 1999 determination.

Of the DNSPs, only Country Energy and EnergyAustralia made specific comments related to the return of capital. Their comments focused on the possibility of introducing flexibility in the profiling of depreciation to allow price smoothing, while at the same time allowing the businesses to maintain the value of their investments in net present value terms over the life of the assets. Specifically, they suggested that the Tribunal allow them to defer depreciation to the next regulatory period.

The DNSPs' concern about the profiling of depreciation stems from the fact that the Tribunal's decision to use a glide path approach when setting the price path for the regulatory period (discussed in Chapter 7) will result in a NPV revenue loss for their businesses. The Tribunal believes that this concern cannot be addressed separately from the issue of the price path, which involves a balancing of interests between customers — current and future— and the DNSPs and their owner. For this reason, its considerations and decisions in relation to the proposed deferral of depreciation are discussed in chapter 7.

Putting aside the issue of the deferral of depreciation, the DNSPs generally supported the decision to use the straight line depreciation method. They agreed in principle with the Tribunal's view that this approach is simple, consistent and transparent. EnergyAustralia was the only DNSP to propose alternative asset lives.

Other stakeholders did not comment on the Tribunal's draft decisions.

6.3.3 Tribunal's considerations in making its final decisions

In making its final decisions on the depreciation allowance, the Tribunal considered all the stakeholder comments it received on this issue, as well as expert advice. Its key considerations in relation to each of its final decisions are outlined below.

Straight line depreciation method used to calculate depreciation allowance

For the purpose of calculating the return of capital (depreciation) allowance to be included in the DNSPs' notional annual revenue requirements, the Tribunal decided to continue to use the straight line depreciation method. In making this decision, it recognises that there is no one 'best' approach to calculating this allowance, and that under particular circumstances one depreciation profile might be preferred to another. However, its own analysis indicates that the straight line approach is simple, consistent and transparent.

The Tribunal also took into account the fact that the DNSPs, in submissions to the review, generally supported the continued use of the straight-line depreciation method. They also pointed out that the straight line approach is used for financial accounting purposes, and that most regulators and electricity distributors throughout Australia have adopted this approach.

In addition, the Tribunal considered the advice of Allen Consulting,[81] which it commissioned to provide advice on the appropriate treatment of depreciation. Allen Consulting recommended that:

> The current approach – straight-line depreciation in inflation-indexed terms – should be retained…The application of straight-line depreciation is simple, consistent with what has been done in the past, and consistent with that applied to all other regulated energy distributors serving mature markets.[82]

EnergyAustralia's proposed asset lives applied in calculating its allowance

To apply the straight line depreciation method, the Tribunal requires estimates of the lives of the assets being depreciated. In the draft determination, the Tribunal applied the asset lives proposed by EnergyAustralia and indicated that it would commission an independent assessment of their proposed asset lives. For the other three DNSPs it used the lives in the 1999 determination, which were based on NSW Treasury's 1999 study. However, it indicated that it would consider using alternate asset lives proposed by any DNSP.

81 The Allen Consulting Group, *Principles for determining regulatory depreciation allowances*, September 2003.

82 The Allen Consulting Group, *Principles for determining regulatory depreciation allowances*, September 2003, p 2.

No changes in asset lives were proposed in response to the draft report. EnergyAustralia's proposed alternate asset lives are, on average, longer than the asset lives used in the 1999 determination. The Tribunal commissioned Burns and Roe Worley (BRW) to independently review EnergyAustralia's proposed asset lives. Specifically, it asked BRW to:

- indicate whether the standard and remaining asset lives proposed are reasonable in light of the average condition of the assets, by considering factors such as load growth, aging due to stress, maintenance, environmental conditions, reliability and demographic changes
- if the proposed lives are not reasonable in light of the above, explain why
- advise on whether the standard and remaining lives should be the same for all DNSPs or whether they should differ between DNSPs and, if so, reasons for the differences.

BRW generally endorsed EnergyAustralia's proposed asset lives.[83] Based on its examination of the various methodologies the DNSP used to determine the asset lives for each asset category, it found that:

> … a substantial and impressive effort has been made to determine these lives given the legacy records of previous organisations and the mass of data involved. BRW points out that records of thousands of items of equipment are involved, stretching back over fifty years of installations.
>
> BRW is of the view EnergyAustralia has employed logical and defensible methodologies to determine their asset lives and that no inappropriate biases have been detected.
>
> BRW supports EnergyAustralia's proposed asset lives and considers that from an engineering perspective the changes in lives are satisfactory and appropriate. BRW has the view that the increase in lives for particular asset categories will not impact on EnergyAustralia's ability to comply with the requirements of the National Electricity Code or their ability to supply reliable and safe electricity supply to their customers.[84]

In its recommendation to the Tribunal, BRW also wrote:

> Finally, it is BRW's view that the asset lives proposed by EA should be adopted by IPART for the 2004 determination, except for the IT System asset categories. For the Metering and Load Control asset category, there is a reasonable probability that the assets in this category will fulfil or exceed the remaining life. As insufficient detailed records on meters were provided, BRW was unable to make an informed assessment on the engineering life, although EA's supposition is considered to be technically feasible.[85]

83 BRW, *Review of EnergyAustralia's Asset Lives*, May 2004.
84 BRW, *Review of EnergyAustralia's Asset Lives*, May 2004, p 24.
85 BRW, *Review of EnergyAustralia's Asset Lives*, May 2004, p 25.

In light of BRW's report, the Tribunal has accepted EnergyAustralia's proposed standard and remaining asset lives, with the exception of IT System asset categories in its financial modelling for the determination.

For the IT system asset categories, the standard life proposed by EA reduces the standard life used by IPART in the 1999 determination by 1 year. It is BRW's view that this reduction is unnecessary in light of recent upgrades to the EnergyAustralia IT system for the introduction of FRC. From an engineering perspective, as opposed to the financial perspective taken by EnergyAustralia (based on the depreciable tax life used by the Australian Taxation Office), a five year expected life was considered by BRW to be more appropriate.

The Tribunal also recognises that there is some uncertainty over the remaining asset life for the Metering and Load Control asset category. BRW was unable to make an informed assessment about the remaining life for this category. It did, however, consider that EA's proposed remaining life of 18 years was technically feasible. In light of this uncertainty and the fact that a higher asset life for this category helps mitigate the significant price impacts on customers, the Tribunal has decided to accept EnergyAustralia's proposed remaining life of 18 years. BRW accepted EnergyAustralia's proposed adjustment to the standard life for this category of assets.

With the exception of the standard asset life for IT System categories, the Tribunal therefore decided to adopt EnergyAustralia's asset lives in its financial modelling to calculate the depreciation allowance for the 2004-09 regulatory period. The changes in asset lives will apply on a prospective basis only — that is, the changes will apply from 2004/05. The Tribunal will not recalculate depreciation for the 1999-04 regulatory period. This is consistent with accounting conventions and ensures that the net present value of the depreciation allowances does not change over the life of the assets. The Tribunal's 1999 report to the Premier contains a fuller discussion of this point.[86]

BRW also considered whether EnergyAustralia's proposed asset lives could be applied to the other DNSPs. It noted:

> The factors influencing the engineering life of an asset generally vary only marginally between different DNSPs. These factors … are:
>
> - Original quality of equipment and its Installation;
> - Design of installation;
> - Climatic conditions;
> - Utilisation factors and duty experienced;
> - Maintenance practices;
> - Operating environment; and
> - Technical or functional obsolescence.
>
> Different DNSPs may have taken different historical approaches to these factors. In particular utilisation and maintenance can have significant impacts on asset lives. Therefore the standard life for each asset category will in general be different from one DNSP to the next. Assessment of DNSP practices is therefore important to determine the standard asset life for a particular DNSP.

86 IPART, *Pricing for Electricity Networks and Retail Supply, Report Volume 1*, Report Rev99-5.1, June 1999, pp 100-102.

> The quality of actual age data and completeness of knowledge will also vary between DNSPs. A DNSP needs to build accurate age profiles for each category of plant/equipment and this can be difficult to do if sound historical data is not available. Assessment of these points for each DNSP is an important input in assessing whether to adopt the same standard and remaining life figures for a particular DNSPs.[87]

Based on BRW's advice, the Tribunal is satisfied that it would be inappropriate to apply the EnergyAustralia's asset lives to the other DNSPs without a full engineering assessment. Therefore, it decided to apply the asset lives used in the 1999 determination for Integral Energy, Country Energy and Australian Inland when calculating their depreciation allowances.

6.4 Allowance for the cost of working capital

The Tribunal is of the view DNSPs should be allowed to recover the cost of maintaining an investment in working capital. Since the allowances for a return on and of capital invested in fixed assets in the cost building blocks is just sufficient to cover these costs, a separate amount is made available for working capital. The Tribunal's final decision on this allowance, and the analysis behind this decision is summarised below.

6.4.1 Final decisions

The Tribunal has decided to include an allowance for working capital in the cost building blocks, based on a simplified payment cycle approach.

The allowance for working capital for each DNSP is shown in Table 6.5.

Table 6.5 Allowance for cost of working capital, 2004/05 to 2008/09 (nominal values)

DNSP	2004/05 $m	2005/06 $m	2006/07 $m	2007/08 $m	2008/09 $m
EnergyAustralia	6.5	6.1	6.1	6.6	7.2
Integral Energy	2.5	2.7	3.0	3.4	3.8
Country Energy	3.8	4.1	4.5	4.9	5.2
Australian Inland	0.3	0.3	0.3	0.3	0.3

6.4.2 Summary of responses to draft decision

The Tribunal's final decision affirms the approach for calculating the working capital allowance set out in the draft decision—it estimated a reasonable level of working capital for each DNSP using a simplified payment cycle approach. Specifically, this approach is based on the amount of time that payments (based on operating and capital expenditure) and receipts (network revenue) are outstanding. The calculation also adds in the value of inventory (which is also based on the level of capital and operating expenditure). Since the building block revenue requirement is expressed in nominal terms, the return on net working capital is calculated as a nominal return equivalent to the rate of return applied to the regulatory asset base.

[87] BRW, *Review of EnergyAustralia's Asset Lives*, May 2004, p 22.

Thus, working capital is calculated as follows:

- Receivables (including pre-payments and accrued revenue) @ 45 days of total network revenue (DUOS + TUOS + other network regulated) *less*
- Payables @ 30 days of operating costs (including TUOS costs) + capital expenditure *plus*
- Inventory @ number of days of operating costs (excluding TUOS costs) + capital expenditure as at 30 June 2003.

No stakeholder expressed concern about this overall approach. However, Origin Energy took issue with the decision to allow 45 days for receivables and only 30 days for payables in calculating the working capital allowance. It argued that since almost all of a DNSP's customers are retailers not end-use consumers, "…on a business to business basis, the same number of days should be expected for receivables as for payables'. It also noted "…if a ring-fenced DNSP operates at arms length with its retail business, then this should be expected from the DNSP as it applied to other retailers".

6.4.3 Tribunal's considerations in making its final decisions

In making its final decision to retain this billing cycle approach, the Tribunal considered Origin Energy's concern. However, the Tribunal is of the view that it is appropriate for the allowance for receivables to be greater than the deduction for payables (45 days versus 30 days) to provide compensation for working capital associated with pre-payments and accrued revenue, as there is no explicit allowance for these items under the Tribunal's simplified billing cycle approach. While admittedly a simplification, this approach is easy to understand and is consistent with the approach it took in the 1999 determination. On balance, the Tribunal considers that the simplified approach provides an adequate but not over-generous working capital allowance for DNSPs.

6.5 Incorporating DNSPs' closing unders and overs account balances

The revenue cap form of regulation under the Tribunal's 1999 determination required the operation of an unders and overs account to record any under- or over-recovery of the DNSP's Aggregate Annual Revenue Requirement (AARR). None of the DNSPs expect to have a zero balance by the end of the current regulatory period on 30 June 2004.

Under the weighted average price cap form of regulation, revenue is not capped so an unders and overs account arrangement will not be required for DUOS tariffs.[88] This means the Tribunal needs to decide how to incorporate the closing account balances from the current regulatory framework into the proposed regulatory framework for the 2004-09 regulatory period. The Tribunal's final decisions, a summary of its draft decisions and stakeholder responses to these decisions, and its considerations in making its final decisions are set out below.

88 The Tribunal has, however, introduced a transmission overs and unders account to account for differences in actual transmission costs and revenues in each year.

6.5.1 Final decisions

The Tribunal has decided to incorporate the outstanding unders and overs account balances into the notional revenue requirements for the 2004-09 regulatory period:

- **The forecast closing balance at 30 June 2004 will be added/deducted from the notional revenue requirements depending on whether a closing under/over recovery balance is forecast.**
- **Any forecast error resulting from a difference between the actual closing balance as at 30 June 2004 and the forecast closing balance that is incorporated into the notional revenue requirements for use in the determination will be added to the transmission overs and unders account.**

The Tribunal has also decided not to allow EnergyAustralia's proposed adjustment to the unders and overs account as a result of revisions to its distribution loss factors and historical revenue estimates.

The amounts to be incorporated into the building block revenue requirements are listed in Annexure 8 of the determination. The annual adjustments to the notional revenue requirements for each DNSP are shown on Table 6.6.

Table 6.6 Adjustments to building block revenue requirements for closing unders and overs account balance, 2004/05 to 2008/09 (nominal values)

DNSP	2004/05 $m	2005/06 $m	2006/07 $m	2007/08 $m	2008/09 $m
EnergyAustralia	-20.8	-22.8	-25.0	-27.4	-30.1
Integral Energy	-15.3	-16.8	-18.4	-20.2	-22.1
Country Energy	0.4	0.4	0.4	0.5	0.5
Australian Inland	0.7	0.7	0.8	0.9	1.0

6.5.2 Summary of responses to draft decisions

The Tribunal's final decision on incorporating the outstanding unders and overs account balances is the same as its draft decision. The Tribunal's draft decision incorporated the following closing balances:

- Country Energy — under-recovery balance of $1.7 million
- Australian Inland — under-recovery balance $3.2 million
- EnergyAustralia — over-recovery balance of $99 million
- Integral Energy — over-recovery balance of $73 million.

Country Energy agreed with the Tribunal's proposed treatment of its under-recovery balance, but submitted that any negative revenue carryover resulting from a forecasting error should be set to zero. It argued that since the Tribunal's approach to setting the X-factors does not allow DNSPs to recover their notional revenue requirements, any negative carryover into the residual transmission overs and unders account would effectively penalise the distribution businesses twice.[89]

EnergyAustralia and Integral Energy expressed concerns about the Tribunal's proposed treatment of their over-recovery balance, based on the impact it would have on the transition of prices into the 2009 regulatory period. EnergyAustralia submitted that under a glide path approach, if applied at the next regulatory period, the Tribunal's treatment of the over-recovery balance means it will incur an additional penalty as a result of the gliding of revenues back up to the level of underlying costs in the 2009 regulatory period.[90] Integral Energy made a related point, arguing that a P-nought adjustment would be required at the next regulatory reset to return prices back to the level of underlying costs. It estimated that a P-nought of 4 per cent would be required at the next regulatory reset, all other things equal.[91]

EnergyAustralia also argued that it is appropriate for the over-recovery balance to be written off because, given its substantial, prudent overspending on capital and operating costs, prices should have been higher than they were in the 1999-04 regulatory period. It stated that against this background, it is inappropriate to argue that customers had paid too much (and so contributed to the over-recovery balance) and so the over-recovery should be shared more equitably between customers and EnergyAustralia.[92] It further argued that the Tribunal could write off its over-recovery balance against the net present value revenue loss incurred under the glide path approach to setting prices.[93]

EnergyAustralia has proposed an adjustment to its forecast closing balance to reflect changes in historical distribution loss factors (DLFs), and the impact of these changes on its calculation of network revenue and its unders and overs account closing balance.[94] EnergyAustralia estimated that the cumulative impact of lower-than-actual DLFs on the unders and overs account over the balance at end of June 2004 is that its over-recovery balance is overstated by approximately $17 million. It proposed an adjustment to the financial year 2004 regulatory account by reducing the accumulated over-recovery balance by this amount.

6.5.3 Tribunal's considerations in making its final decisions

The Tribunal considered the DNSPs' arguments carefully, as well as a range of other issues including the impact of its decisions on price stability and intergenerational equity. Its key considerations in making its final decisions are outlined below.

89 Country Energy submission to the draft determination, March 2004, p 80.

90 EnergyAustralia submission to the draft determination, March 2004, p 54.

91 Integral Energy submission to the draft determination, March 2004, p 32.

92 EnergyAustralia submission to the draft determination, March 2004, pp 54-55.

93 EnergyAustralia submission to the draft determination, March 2004, p 36.

94 As part of its process for estimating distribution loss factors (DLF), EnergyAustralia undertook a detailed analysis of distribution losses on its network. This analysis involved a reconciliation of purchases less sales for the financial years 2001 to 2003 and found that the DLFs that were published by NEMMCO and used during the 1999 regulatory period have understated the true distribution losses. As a result of the change in how DLFs are calculated, EnergyAustralia estimates that it had overstated its network revenue in both its regulatory and statutory accounts between 2001 and 2003. Letter to the Tribunal, 3 March 2004.

The forecast closing unders and overs account balance will be incorporated into the notional revenue requirements

The Tribunal strongly believes the closing unders and overs account balance should be resolved during the 2004-09 regulatory period. Several non-DNSP stakeholders supported this in their submissions to the review.[95] The Tribunal is of the view it is not appropriate to write off the closing over-recovery balances in light of the higher than expected capital and operating costs incurred during the 1999-04 regulatory period. Over-recovery balances have arisen because DNSPs have earned more revenue than allowed for under the 1999-04 determination's revenue cap. If the Tribunal were to write off the closing over-recovery balance there would, in effect, be no penalty to the DNSP for breaching the Tribunal's determination. Similarly, writing the balance off against the net revenue loss would ignore the incentive properties of the Tribunal's glide path approach to the price path (as discussed in Chapter 7).

In the case of over-recovery balances, the Tribunal has taken the approach that the balances should be incorporated into the regulated revenues in the 2004-09 regulatory period to help achieve both intergenerational equity and price stability. Current customers, who have paid more than allowed under the 1999 determination, are more likely to benefit from the lower prices under this approach. Deducting the over-recovery balances from the notional revenue requirements in 2004-09 will also reduce expected price increases to a certain degree.

In the case of under-recovery balances, it has taken the approach that the balances should be incorporated into the regulated revenues in the 2004-09 regulatory period to help achieve intergenerational equity as outlined above. It recognises that this will tend to increase prices during the 2004-09 regulatory period compared to what they would otherwise have been. However, the constrained price path it has determined for Country Energy and Australian Inland (see chapter 7) mitigates this problem to a significant degree.

The closing unders and overs account balances have been incorporated into the building block revenue requirements evenly across the regulatory period — that is, 20 per cent each year. The amount included in these revenue requirements has also been inflated by the nominal rate of return, to ensure that the recovery amount is maintained in net present value terms. The Tribunal is of the view that this approach is a neutral method of including the outstanding account balance into the building block revenue requirements.

The Tribunal recognises EnergyAustralia and Integral Energy's concerns about the transition of prices into the next regulatory period commencing in 2009. However, it considers that it is important that it is transparent to all stakeholders that customers are benefiting from the return of over-recovery balances from the 1999-04 regulatory period. Under the Tribunal's glide path approach, there must be some adjustment to the final year notional revenue requirements for this to occur. EnergyAustralia proposed an approach to sculpt the return of the over-recovery balance to target the unadjusted notional revenue requirement in the final year. Although this would be a net present value neutral approach, the Tribunal is of the view that it would not provide a good balancing of outcomes between customers and the DNSPs and its owner (see Chapter 7).

95 For example, PIAC submission, March 2004, p 4.

The Tribunal notes that the transition of prices issue represents a problem in terms of *expected* costs at the end of the year. Whether a price adjustment will indeed be required will depend on what actual growth in costs materialises over the regulatory period. Lower than anticipated costs (eg through lower than expected demand or efficiency improvements) would reduce the need for a price adjustment at the start of the 2009 regulatory period. While, in principle, it would be desirable for the Tribunal to minimise expected transitional issues in its price path, the desirability of returning the over-recovery balance requires some trade-offs to be made. Against the background of its preferred glide path approach to setting prices, the Tribunal considers that its approach to the unders and overs account represents a pragmatic balancing of outcomes.

The forecast error will be added to the transmission over and under account

The Tribunal has decided that any difference between the forecast closing balance and the actual closing balance ('the forecast error') is to be added to the Transmission overs and unders account that will be established for the recovery of transmission-related costs (see Chapter 13). The Tribunal is satisfied that this is a simple and practical approach that guarantees that the closing distribution unders and overs account balance will be fully reflected in the DNSPs' revenue requirements.

The Tribunal considered other options including incorporating it into the weighted average price cap formula via a correction factor or, making no adjustment for the error. The Tribunal believed an adjustment is necessary, however it considers that adding a correction factor to the weighted average price cap formula would increase the complexity of the formula.

In addition, the Tribunal does not consider it appropriate to write-off any negative carryover amount as proposed by Country Energy. A negative carryover amount would mean that the DNSP's forecast over-recovery balance was under-stated or the forecast under-recovery balance was over-stated. In this situation, if the closing balance of the unders and overs account had been accurately predicted, then the hybrid P-nought/glide path approach adopted by the Tribunal in setting prices (see Chapter 7), would have led to a lower price path for the DNSPs.[96] The Tribunal is of the view that it is appropriate for the negative carryover amount to be reflected in the transmission overs and unders account, to the benefit of customers.

Since the draft report, Integral Energy has revised their forecast over recovery balance from \$73m to \$88m. This forecast is impacted by forecast kWh through-put during 2003/04. Rather than using this revised forecast the Tribunal considers its prudent to use the draft report forecast and for any difference between the forecast closing balance and the actual closing balance ('the forecast error') is to be added to the Transmission overs and unders account that will be established for the recovery of transmission-related costs.

96 In Country Energy's case, this would have reduced the amount of deferred depreciation the Tribunal allowed.

The Tribunal will not allow EnergyAustralia's proposed adjustment to its over-recovery balance

The balance of the unders and overs account is calculated each year as part of a DNSP's regulatory accounts in accordance with Rule 2001/3 Unders and Overs Account. The revenue information is audited annually - it is subject to both EnergyAustralia's statutory audit as well as the review procedures undertaken on the regulatory accounts.

The Tribunal considers that it would be poor regulatory practice to revise historical outcomes, in light of revisions to methodologies used to collect/generate data — especially when this revenue data has been audited. The use of audited data is intended to provide a degree of confidence for all stakeholders over regulated outcomes. Ex-post revisions, particularly to audited data, would undermine both this confidence and also the stability and predictability of the regulatory regime. Allowing an ex-post adjustments would also reduce incentives for DNSPs to ensure that their information systems are generating the most accurate data available.

For these reasons, the Tribunal has decided against allowing EnergyAustralia's proposed adjustment to the unders and overs account balance for changes in its estimated DLFs.

The Tribunal has also decided to use the over-recovery forecast provided by EnergyAustralia in the lead up to the draft report. EnergyAustralia's subsequent March 2004 forecast does not correctly account for the impact of the GST when it was introduced in 2000. The Tribunal believes that it is appropriate for this issue to be resolved at the time the regulatory accounts for 2003/04 are finalised. For this reason, the Tribunal has adopted the forecast used in the draft decision as the forecast closing balance for 2003/04 to be incorporated into the notional revenue requirements. To ensure consistency of treatment across the DNSPs, the Tribunal has adopted the forecast balances from the draft decision for the other DNSPs also.

6.6 Notional annual revenue requirements

To determine the notional annual revenue requirements for each DNSP, the four cost building blocks discussed in this chapter are added together. The resulting requirements for each DNSP for each year of the next regulatory period are shown in Table 6.7.

In determining these revenue requirements, the Tribunal has adopted a financial view of the regulatory asset base. This financial view means that, on a forward looking basis, in providing a return on and of capital, the Tribunal seeks to maintain shareholder's financial investment in real terms. However, it is also required under the Code to have regard to a wide range of matters including public interest and price stability. **So, while the Tribunal determines individual building blocks based on a financial view, it then has taken into account other matters it is to have regard to under the Code to determine an appropriate price path.** Its decisions on the price path for each DNSP are discussed in the Chapter 7.

Table 6.7 Notional annual revenue requirement for each DNSP, 2004/05 to 2008/09 ($nominal)

$M	2004/05	2005/06	2006/07	2007/08	2008/09
EnergyAustralia					
Operating expenditure	288	303	312	319	326
Return of capital (depreciation)	170	187	205	223	243
Return on capital	295	318	340	362	384
Return on working capital	6	6	6	7	7
Unsmoothed revenue requirements	760	815	863	912	960
Less correction of previous under/over recovery balance	21	23	25	27	30
Notional revenue requirements	739	792	838	885	930
Integral Energy					
Operating expenditure	208	214	221	229	236
Return of capital (depreciation)	130	144	158	172	186
Return on capital	166	181	195	209	220
Return on working capital	3	3	3	3	4
Unsmoothed revenue requirements	507	542	578	613	646
Less correction of previous under/over recovery balance	15	17	18	20	22
Notional revenue requirements	492	525	559	593	624
Country Energy					
Operating expenditure	222	231	240	249	259
Return of capital (depreciation)	132	147	163	180	197
Return on capital	171	182	192	202	211
Return on working capital	4	4	4	5	5
Unsmoothed revenue requirements	529	564	600	635	672
Less correction of previous under/over recovery balance	(0)	(0)	(0)	(0)	(1)
Notional revenue requirements	529	564	600	636	673
Australian Inland					
Operating expenditure	10	10	10	10	11
Return of capital (depreciation)	3	3	4	4	4
Return on capital	5	5	5	5	5
Return on working capital	0	0	0	0	0
Unsmoothed revenue requirements	18	19	19	20	20
Less correction of previous under/over recovery balance	(1)	(1)	(1)	(1)	(1)
Notional revenue requirements	19	19	20	20	21

Columns may not add due to rounding.

7 CALCULATING THE AMOUNT BY WHICH AVERAGE DISTRIBUTION PRICES CAN CHANGE (THE X-FACTORS)

To calculate the amount by which average distribution prices can change in each year of the regulatory period, the Tribunal first considers the values it has established for each building block component for each DNSP, and determines the notional annual revenue requirement for each DNSP (see Chapter 6). Then, taking into account the DNSP's growth forecast (see Chapter 4), it calculates the amount by which its current average prices would need to rise or fall in each year of the regulatory period to generate its required revenue. This amount is represented by the X-factor in the weighted average price cap formula.

However, in calculating the X-factors, the Tribunal has determined an appropriate price path that balances the interests of the DNSPs and their owner with the interests of customers. This involves targeting a 'smoothed' annual revenue requirement, so that the resulting price changes are spread more evenly over the regulatory period and/or constraining price changes to avoid stakeholder outcomes that are unacceptable under the Code.

The Tribunal's final decisions on the amount by which average distribution prices can change and the approach used to calculate this amount are summarised below. The rest of this chapter outlines the Tribunal's draft decisions and stakeholders' responses to these decisions, explains the Tribunal's considerations in making its final decisions, and discusses the main implications of the decisions for customers, the DNSPs and their owner.

7.1 Summary of final decisions

The Tribunal has decided that average distribution prices may increase annually by the change in CPI plus an 'X-factor' as shown in Table 7.1.

Table 7.1 DNSPs' distribution price outcomes

	Standardised DNSP's proposals[97]		Final decision	
	DNSP's proposed annual price increase – distribution	NPV of costs not recovered	Annual distribution price increase	NPV of costs not recovered
EnergyAustralia	CPI + 19.4% in 2004/05 then CPI + 1%	0	CPI + 7% in 2004/05 then CPI+1.6%	\$50m
Integral Energy	CPI + 11.1% in 2004/05 then CPI + 1%	0	CPI + 5% in 2004/05 then CPI +1.5%	\$22m
Country Energy	CPI + 13.2% in 2004/05 then CPI plus 5.7%	\$233m	CPI + 7% in 2004/05 then CPI + 2.5%	\$114m
Australian Inland	CPI + 15.6% in 2004/05 then CPI + 6.6%	\$12m	CPI + 7% in 2004/05 then CPI + 2.5%	\$14m

97 In developing their pricing proposals in April 2003, the DNSPs used differing assumptions over a number of parameters. Table 7.1 presents each DNSP proposal based on a common assumption for inflation, and a common split between prescribed and excluded services.

In making this decision, the Tribunal has used a hybrid P-nought/glide path revenue smoothing approach for all DNSPs.

The Tribunal has also decided for Country Energy only, to allow for some deferral of depreciation.

7.2 Summary of draft decisions and stakeholder responses

The draft report outlined four broad approaches for calculating the amount by which average prices can change over the regulatory period:

1. **Net Present Value (NPV) approach with single X-factor**: a single X-factor is set to ensure that the DNSP's expected revenue equals its notional revenue requirement in NPV terms throughout the regulatory period.
2. **NPV approach with P-nought adjustment**: an initial X-factor is set for the first year of the regulatory period to ensure that the DNSP's expected revenue equals its notional revenue requirement for that year. A second X-factor is set for the rest of the regulatory period, to ensure that its expected revenue equals its notional revenue requirements over the entire regulatory period.
3. **Straight line revenue smoothing, or glide path:** a single X-factor is set to ensure that prices change smoothly over the regulatory period in real terms, and that the DNSP's expected revenue in the final year of the regulatory period equals its notional revenue requirement for that year.
4. **Hybrid P-nought/glide path**: an initial X-factor is set for the first year of the regulatory period to allow the DNSP's prices to change sufficiently in that year to move its expected revenue closer to its notional revenue requirement. A second X-factor is set for the rest of the regulatory period to target expected revenue in the final year of the regulatory period to equal its revenue requirement for that year.

The Tribunal's draft decision was to use a hybrid P-nought/glide path approach for EnergyAustralia, Country Energy and Australian Inland as this approach would:

- provide a better balance between incentives and price impacts on the one hand, and the level of revenue recovery on the other
- make it easier for the Tribunal to manage competing outcomes in the overall price review—such as the financial risks facing these businesses, and the need to ensure that they have sufficient revenue to make expenditures necessary to maintain service standards.

For Integral Energy, its draft decision was to use a straight line revenue smoothing approach. It considered that, given the expected profile of Integral Energy's notional revenue requirements, a P-nought adjustment was not required.

In applying these approaches, the Tribunal proposed a price path that aimed to generate smoothed annual revenue requirements for each DNSP. For Country Energy and Australian Inland, the proposed price path aimed to generate significantly less revenue than the sum of their building block costs, to ensure acceptable price outcomes for their customers. For EnergyAustralia and Integral Energy, it aimed to generate revenue that by 2008/09 would be broadly in line with their building block costs.

Stakeholders raised several issues in response to these draft decisions, particularly to the way the Tribunal had sought to balance competing outcomes. In general, the DNSPs argued that the Tribunal had put too much weight on price outcomes for customers at the expense of the financial outcomes for DNSPs. They also commented that:

- the hybrid P-nought/glide path approach does not provide an NPV neutral revenue stream, which has negative implications for DNSP investment
- this approach is not an appropriate mechanism for increasing incentives to DNSPs to seek out efficiency improvements, particularly toward the end of the regulatory period
- this approach could result in a loss of business value for the DNSPs. Country Energy and EnergyAustralia both proposed that the Tribunal allow for the deferral of depreciation (return of capital) into the next regulatory period as a means of retaining business value and achieving a more balanced outcome.

7.3 Tribunal's considerations in making its final decisions

In making its final decisions on the amount by which the DNSPs' average prices can move each year from 2004/05 to 2008/09, the Tribunal has carefully considered all stakeholder views, and the principles and objectives of the Code. It also considered the relative merits of the four approaches to setting the price path, and the current level of prices. Its considerations in relation to these decisions are explained below.

7.3.1 A hybrid P-nought/glide path approach used for all DNSPs

The Tribunal decided to use a hybrid P-nought/glide path approach when calculating the amount by which average prices can increase for all DNSPs. As a result, it has set price paths based on smoothed annual revenue requirements for all DNSPs. For EnergyAustralia and Integral Energy, the price path aims to generate annual revenue consistent with their building block costs by 2008/09. However, for Country Energy and Australian Inland, the price path aims to generate annual revenue that is somewhat less than their building block costs by this time.

In making these decisions, the Tribunal recognised that the approach taken to determine the price path involves trade-offs among a range of criteria. The criteria the Tribunal considered were:

- price stability (that is, impacts on customers)
- revenue recovery (financial outcomes for DNSPs)
- incentives for efficiency
- transitional issues into 2009 regulatory period
- consistency with the 1999 determination.

(See Appendix 9 for more information on the four approaches the Tribunal considered, and an evaluation of the likely outcomes for each approach.)

Considerations in relation to the hybrid P-nought approach

The Tribunal considered the DNSPs' concerns that the hybrid P-nought/glide path approach does not provide an NPV neutral revenue stream, and thus has negative implications for investment. It notes that unlike the Gas Code, the National Electricity Code does not explicitly require the Tribunal to take an NPV neutral approach. Rather, it requires it to *have regard* to a number of matters (including a sustainable return for DNSPs), and to use its discretion to balance competing issues such as equity and price stability to seek to achieve the range of outcomes listed in Clause 6.10.2 of the Code.

The different approaches to setting the price path will result in different outcomes for different stakeholders. A NPV neutral approach will lead to higher prices for customers, whereas a glide path approach (including the hybrid P-nought/glide path approach) will result in lower expected rates of return for the DNSPs. The Tribunal considered the likely impact of these lower rates of return on incentives for investment. Other things being equal, rates of return lower than the opportunity cost of funds (as reflected in the WACC) could provide a disincentive for investors to commit funds to the business. However, if the glide path approach were seen by DNSPs/investors as a form of symmetrical efficiency carryover that has been and will be applied consistently across past and future regulatory periods, then any disincentive to investment would be reduced.

The Tribunal is of the view that the lower returns should be seen in the context of a wider picture across a number of regulatory periods, whereby the glide path offers expected rates of return that are higher than the allowed rate of return in some periods and lower that the allowed rate of return in others, but on average deliver a return on investment around the level of the allowed rate of return. In this regard, the Tribunal notes that in the 1999 determination, it set a glide path for the metropolitan DNSPs that offered expected returns on assets in the early years of the regulatory period, which were in excess of the allowed rate of return of 7.5 per cent.

The Tribunal also considered the DNSPs concerns about whether the hybrid P-nought/glide path approach is an appropriate mechanism for increasing their incentives to seek out efficiency improvements, particularly toward the end of the regulatory period. It has discussed the properties of a glide path approach in a number of forums. In particular, it considered this approach in relation to the price path for the 1999 determination, where costs for the metropolitan DNSPs were expected to fall at the beginning of the 1999 regulatory period — largely as a result of an externally induced reduction in the WACC for these businesses. It put the view then, and in earlier forums, that a glide path approach was superior to other efficiency carryover mechanism because it:

- is simple to apply and less information intensive than other carryover mechanisms
- is symmetrical and certain
- offers stronger incentives than other cost-linked approaches to efficiency carryover
- reduces price and revenue shocks
- is likely to offer the best balance of benefits and risks for various stakeholders.[98]

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98 IPART, *Regulation of Electricity Network Service Providers, Incentives and Principles for Regulation - Discussion Paper*, DP-32, January 1999.

The Tribunal considers that this view remains valid—including the incentive benefits of the glide path approach. Given this, it considers the hybrid P-nought/glide path approach to be the most appropriate approach for calculating price movements for all DNSPs for the 2004-09 regulatory period. For the same reason, it has decided against adopting a fixed-term efficiency carryover mechanism in this regulatory period.

It should be noted that while the ESC in Victoria has taken a NPV neutral approach, its framework applies the NPV calculation after the incorporation of a glide path — that is, the building blocks are directly adjusted for efficiency carryover before the NPV neutral price path is calculated. The Victorian model does not distinguish between management induced and windfall cost variations due to the difficulties of doing so — any divergence between actual and forecast values is carried over. Adopting this approach would be likely to result in similar outcomes as a glide path approach in this regard. It would also mean that the DNSPs bear the risk of macro-economic fluctuations affecting costs for a period of time — as they do under the Tribunal's hybrid P-nought/glide path approach.

It should also be noted that, although the Tribunal used the straight line revenue smoothing approach in setting the price path for Integral Energy in its draft determination, it has used the hybrid P-nought/glide path approach in the final determination. The cost information Integral Energy provided to the Tribunal in its 2003 submission suggested that its allowed price increases would not be high enough to warrant using the hybrid approach. However, based on Integral Energy's revised projections for capital and operating expenditure and the timing of this expenditure, the Tribunal now believes the P-nought/glide path approach is appropriate.

Considerations in relation to the price path for each DNSP

After considering the interaction of each DNSP's key building block costs, the implications of these costs for its profitability and prices, and the overall implications for all stakeholders, the Tribunal made a judgement on the appropriate price path for each DNSP. This approach is in line with its previously stated view that it does not support the application of a procedure-bound methodology in which key decisions on major components of the revenue requirements are made in isolation.

The Tribunal particularly took into account the fact that all four DNSPs had requested substantial increases in average distribution prices, and proposed a larger increase in the first year followed by smaller increases in the remaining years (Table 7.1). These proposals were driven primarily by significant increases in both capital and operating expenditures over the five years to 2009. Their total forecast costs for this period are approximately $8.7 billion. This is 37 per cent higher in nominal terms (or 20 per cent in real terms) than their actual expenditure during 2000-2004 regulatory period, which was $6 billion.

The Tribunal is concerned about the high capital and operating expenditures recently undertaken and forecast by the DNSPs. Over the past seven years, demand for electricity has become increasingly peaky, and DNSPs have responded by increasing network investment to meet peak demand. This has resulted in poor asset utilisation. In the next five years, DNSPs claim that their ageing distribution assets will require either increased maintenance or increased replacement programs.

It is also concerned about the magnitude of the price increases proposed by Country Energy and Australian Inland. These DNSPs proposed cumulative real price increases over the five years of 41 per cent and 49 per cent respectively. The Tribunal considers that if allowed, these increases would lead to unacceptable outcomes for customers.

Based on all these factors, and its own analysis of the likely impact on DNSPs' profitability, the Tribunal set a price path for each DNSP that targets the smoothed annual revenue requirements shown in Table 7.2. For Country Energy and Australian Inland, these smoothed revenue requirements are still somewhat below the sum of their cost building blocks in 2008/09. However, the Tribunal's decision to allow Country Energy to defer some depreciation to the next regulatory period (see section 7.3.3) will effectively allow it to retain revenue that is much closer to this sum than is indicated on the table.

Table 7.2 Smoothed annual revenue requirement for each DNSP, 2004/05 to 2008/09 ($nominal)

$M	2004/05	2005/06	2006/07	2007/08	2008/09
EnergyAustralia					
Operating expenditure	288	303	312	319	326
Return of capital (depreciation)	170	187	205	223	243
Return on capital	295	318	340	362	384
Return on working capital	6	6	6	7	7
Unsmoothed revenue requirements	760	815	863	912	960
Less correction of previous under/overs balance	21	23	25	27	30
Notional revenue requirements	739	792	838	884	930
Smoothed revenue requirements	**730**	**772**	**819**	**873**	**929**
Rate of return	6.8%	6.6%	6.6%	6.8%	7.0%
Integral Energy					
Operating expenditure	208	214	221	229	236
Return of capital (depreciation)	130	144	158	172	186
Return on capital	166	181	195	209	220
Return on working capital	3	3	3	3	4
Unsmoothed revenue requirements	507	542	578	613	646
Less correction of previous under/overs balance	15	17	18	20	22
Notional revenue requirements	492	525	559	593	624
Smoothed revenue requirements	**487**	**519**	**550**	**586**	**623**
Rate of return	6.8%	6.8%	6.7%	6.8%	7.0%
Country Energy					
Operating expenditure	222	231	240	249	259
Return of capital (depreciation --- prior to deferral)	132	147	163	180	197
Return on capital	171	182	192	202	211
Return on working capital	4	4	4	5	5
Unsmoothed revenue requirements	529	564	600	636	672
Less correction of previous under/overs balance	-0	-0	-0	-0	-1
Notional revenue requirements	529	565	600	636	673
Smoothed revenue requirements	**481**	**516**	**551**	**588**	**627**
Rate of return	5.0%	5.1%	5.2%	5.3%	5.5%
Australian Inland					
Operating expenditure	10.0	10.1	10.3	10.5	10.6
Return of capital (depreciation)	3.2	3.5	3.7	3.9	4.2
Return on capital	4.6	4.8	4.9	4.9	4.9
Return on working capital	0.3	0.3	0.3	0.3	0.3
Unsmoothed revenue requirements	18.0	18.6	19.2	19.6	20.0
Less correction of previous under/overs balance	-0.7	-0.7	-0.8	-0.9	-1.0
Notional revenue requirements	18.7	19.4	20.0	20.5	21.0
Smoothed revenue requirements	**14.4**	**15.4**	**16.4**	**17.5**	**18.7**
Rate of return	0.8%	1.4%	2.1%	2.9%	3.8%

Columns may not add due to rounding.

The Tribunal is of the view that its decisions on the price paths are in line with the requirements of the Code, under which it determine revenue requirements and average price changes that meet the principles and objectives of the Code. Specifically, clause 6.10.2 provides for reasonable and well-defined regulatory discretion that permits an acceptable balancing of the interests of owners and users and the public interest. It considers that if it were to allow Country Energy and Australian Inland to increase their average distribution prices to a level that would recover the full value of their building block costs, the outcome would be unacceptable for customers and not meet the objectives of public interest and equity as required under the Code.

In its response to the draft report, Country Energy agreed that a balance must be struck between outcomes for customers and owners, but argued that its customers should receive slightly higher real increases over the five years of 22 per cent in real terms. However, the Tribunal considers that its decision to allow Country Energy real price increases of 18.1 per cent over next five years represents an acceptable balancing of stakeholder interests and meets the principles and objectives of the Code.

7.3.2 Deferral of depreciation allowed for Country Energy only

The Tribunal decided to allow some deferral of depreciation for Country Energy only. In making this decision, it considered the DNSPs' view that its draft decision on the price path would result in a loss of business value. It also considered Country Energy's and EnergyAustralia's proposals that the depreciation (return of capital) allowance be deferred into the next regulatory period as a means of retaining this value.

The Tribunal believes that the price paths it has set do not prevent the DNSPs from recovering their depreciation allowance (that is, recovering their invested capital). Rather these price paths imply that, after deducting operating expenditure, depreciation[99] and the cost of working capital, all of the DNSPs will earn positive returns on their regulatory asset bases. That is, the projected revenues earned are sufficient to cover operating costs, allow the return of capital, and enable the businesses to earn a significantly positive expected rate of return on their fixed assets.

The loss of business value (NPV revenue loss) arises because this expected rate of return is less than the allowed rate of return of 7 percent. That is, the expected return on fixed assets is not sufficient to recover the opportunity cost of capital. Under the draft determination, this difference was lost to the DNSP.

The key element of the DNSPs' proposal is that if the Tribunal reduced the depreciation allowance, their building block costs would be correspondingly reduced. As a result, their expected return on fixed assets would increase, since less of the revenue they earn would be assigned to cover the depreciation expense. While the total amount of revenue is unaffected by this treatment of depreciation, the NPV loss is effectively capitalised into the regulatory asset base because the reduced depreciation value means that the regulatory asset value is not written down as much as in the draft determination.

99 As calculated using straight line depreciation — that is, unadjusted.

The strength of the DNSPs' argument depends on the extent to which the glide path approach to setting the price path is viewed, at least in part, as an efficiency carryover mechanism. The Tribunal considers that the hybrid P-nought/glide path it has used represents a trade-off between incentives and price impacts on the one hand, and the level of revenue recovery on the other. As discussed above, it maintains its view that the glide path approach strengthens incentives for DNSPs to seek efficiency gains. The deferral of depreciation would affect this balance by pushing some costs into the future, leading to higher prices for customers in subsequent regulatory periods. The Tribunal's analysis suggests that this impact on future customers would not be material.

However, for EnergyAustralia and Integral Energy, whose price paths target the end-of-period cost building blocks, the Tribunal believes the deferral of depreciation would be **inconsistent** with the view that the glide path is an incentive carryover mechanism. That is, by deferring depreciation, there would be no NPV loss and therefore no negative efficiency carryover. The Tribunal has therefore decided not to allow the deferral of depreciation for these DNSPs.

But for Country Energy, the price path is more than just an efficiency carryover approach. The Tribunal has constrained this DNSP's price path to a real increase of 7 per cent in 2004/05 followed by 2.5 per cent thereafter, which will leave it short of its notional revenue requirements in the final year of the regulatory period. It made this decision to avoid outcomes that are likely to be unacceptable for stakeholders and not meet the objectives of public interest and equity as required under the Code.

The Tribunal has therefore decided to allow some deferral of depreciation for Country Energy only. The amount to be deferred is to be calculated as the difference between:

- the NPV revenue loss under the constrained price path, and
- the NPV revenue loss under a hybrid P-nought/glide path approach, as applied to EnergyAustralia and Integral Energy.

This approach means that Country Energy would bear the NPV revenue loss associated with the efficiency carryover — that is, as if the price path were calculated in the same manner as the metropolitan DNSPs (that is, targeting the notional revenue requirement in the final year). However, the NPV loss associated with further constraining Country Energy's prices below this level would be deferred via the depreciation allowance — that is, it would be borne by future customers.

This decision will result in a net loss in business value for Country Energy of approximately \$114 million. This is significantly lower than the net loss implied by the draft determination, which was \$182 million. The loss reflects the incentive properties of the glide path. The impact of the deferred depreciation on Country Energy's smooth revenue requirement is shown in Table 7.3. This represents the Tribunal's final decision on the smoothed revenue requirements Country Energy and the level of regulatory depreciation allowed by the Tribunal in this determination.

Table 7.3 Country Energy's smoothed revenue requirements after deferral of depreciation

Country Energy	2004/05	2005/06	2006/07	2007/08	2008/09
Operating expenditure	222	231	240	249	259
Return of capital (depreciation)	132	138	143	148	151
Return on capital	123	142	163	186	212
Return on working capital	4	4	4	5	5
Less correction of previous under/over recovery balance	-0	-0	-0	-0	-1
Smoothed revenue requirements	481	516	551	588	627
Rate of return	**5.0%**	**5.5%**	**5.9%**	**6.4%**	**6.9%**

7.4 Implications for stakeholders

In making its final decisions in relation to calculating the amounts by which average prices can change, the Tribunal considered the likely implications of its decisions for key stakeholders—including electricity customers and the DNSPs and their owner.

7.4.1 Outcomes for customers

The Tribunal's analysis indicates that the X-factors shown in Table 7.1 will result in the average cumulative real distribution price increases over the five years to 2009 (from 2003/04 prices) shown in Table 7.4.

Table 7.4 Total distribution price increases (in addition to inflation) over the five years FY2009

Distribution Network Service Provider	Real Cumulative Price Increase
EnergyAustralia	14.0 %
Integral Energy	11.4%
Country Energy	18.1%
Australian Inland	18.1%

This means that distribution prices across NSW will increase in real terms by a total of 14 per cent over the next five years, or approximately 2.7 per cent per annum. Distribution prices typically make up between 20 and 40 per cent of an end-user's electricity bill.

The Tribunal expects that in 2004/05 a typical residential customer living in Sydney[100] would see nominal price increase in their final bill of between $50 to $60 a year (exclusive of GST), or about a $1 per week.[101] Similarly, a residential customer in regional NSW would see nominal price increase in their final bill of around $50 to $70 a year, or about a $1.00 to $1.35 per week.[102] The expected increases in distribution charges and final electricity bills for typical customers for each DNSP in 2004/05 in are shown in Tables 7.5 to 7.8.

Table 7.5 Maximum price increase for typical customers of EnergyAustralia[103] ($nominal)

Customer type	2003/04 distribution bill	2003/04 retail bill	2004/05 distribution bill	2004/05 retail bill	Increase in annual retail bill
Residential					
Low Usage (3000kWh)	140	375	153	410	35
Typical usage without off peak (5600kWh)	224	634	246	683	49
Typical usage with off peak (8900kWh including 3300kWh off peak)	228	778	250	838	61
Business					
Low usage -20 MWh	776	2,185	852	2,356	170
Med usage- 40 MWh	1,424	4,303	1,563	4,639	336
High usage -80MWh	2,720	8,539	2,986	9,205	666

Table 7.6 Maximum price increase for typical customers of Integral Energy[104] ($nominal)

Customer type	2003/04 distribution bill	2003/04 retail bill	2004/05 distribution bill	2004/05 retail bill	Increase in annual retail bill
Residential					
Low Usage (3500kWh, no off peak)	217	488	238	526	38
Typical usage (7500kWh, no off peak)	389	936	427	1,009	73
Typical usage with off peak (9500kWh including 3300kWh off peak)	344	931	377	1,004	73
Business					
Low usage -20 MWh	838	2,245	920	2,421	175
Med usage- 40 MWh	1,610	4,351	1,767	4,691	339
High usage -80MWh	3,154	8,563	3,463	9,231	668

100 A network customer of EnergyAustralia.

101 The retail bill has been increased by CPI+5% -the maximum increase for residential customer under the Tribunal's Retail Determination, June 2004. Prices are ex-GST.

102 The retail bill has been increased by CPI+5% -the maximum increase for residential customer under the Tribunal's Retail Determination, June 2004. Prices are ex-GST.

103 Ibid.

104 Ibid.

Table 7.7 Maximum price increase for typical customers of Country Energy[105] ($nominal)

Customer type	2003/04 distribution bill	2003/04 retail bill	2004/05 distribution bill	2004/05 retail bill	Increase in annual retail bill
Residential - Urban					
Low Usage (3000kWh, no off peak)	220	486	242	524	38
Typical usage (4600kWh, no off peak)	289	682	318	736	53
Typical usage (8300kWh including 40% off peak)	319	905	350	975	71
Business					
Low usage -20 MWh	1,373	2,966	1,507	3,198	231
Med usage- 40 MWh	2,619	5,754	2,876	6,203	449
High usage -80MWh	5,112	11,330	5,612	12,214	884

Table 7.8 Maximum price increase for typical customers of Australian Inland[106] ($nominal)

Customer type	2003/04 distribution bill	2003/04 retail bill	2004/05 distribution bill	2004/05 retail bill	Increase in annual retail bill
Residential - Urban					
Low Usage (3000kWh, no off peak)	133	405	146	440	35
Typical usage (4600kWh, no off peak)	180	585	198	631	46
Typical usage (8300kWh including 40% off peak)	191	781	210	842	61
Business					
Low usage -20 MWh	1,127	2,849	1,237	3,071	222
Med usage- 40 MWh	2,167	5,515	2,379	5,945	430
High usage -80MWh	4,247	10,847	4,663	11,693	846

Note: Rows may not add due to rounding.

The above impacts are before the effects of any tariff restructuring. However, tariff reform may lead to varying customer impacts. EnergyAustralia and Integral Energy have proposed introducing an inclining block network tariff for their small business and residential customers. If they do so, customers who consume small amounts of electricity may see smaller increases, whereas those who consume greater amounts may see price increases greater than those indicated above.

105 Ibid.

106 Ibid.

7.4.2 Outcomes for DNSPs and their owner

The Tribunal expects that its decisions on the amount by which average prices can change will allow DNSPs to maintain their financial viability. NSW Treasury targets an investment grade rating of BBB or higher for state-owned businesses. The Tribunal's analysis and financial modelling indicates that all four DNSPs will be able to maintain or improve their financial position, and earn a reasonable rate of return. It also indicates that the DNSPs can maintain their current investment grade rating for all of the key financial indicators.

Financial outcomes for each of the DNSPs are presented in Appendices 12 to 15. Table 7.9 provides a summary of these outcomes for each of the DNSPs. In most cases, a DNSP's financial ratings are affected by whether its forecast actual gearing or notional gearing is used. The ratings for both actual and notional gearing are presented in the appendices. The actual gearing used is a matter for government as the DNSPs' owner to decide. The extent to which the rate of return is distributed as interest, dividends or retained by the DNSP is a matter for negotiation between the shareholder and DNSP.

Table 7.9 Projected outcomes for the 5 years to 30 June 2009 (2003/04 prices)

$M	EnergyAustralia	Integral Energy	Country Energy	Australian Inland
NPV of costs foregone	50	22	114	14
Cumulative real distribution price increase	14.0%	11.4%	18.1%	18.1%
Average real distribution price as at 30 June 2009 (c/kWh)	2.89	2.92	4.77	5.49
Total EBIT in 2009, $m	349	193	162	3.7
Overall projected NSW Treasury rating in 2009	BBB+	A+	A	NA[1]

Notes
1. NA as Australian Inland is in a net cash position.
2. Projected outcomes are based on actual gearing.

8 PROVIDING INCENTIVES FOR DEMAND MANAGEMENT

Demand for electricity has become increasingly peaky. This has led to constraints in the capacity of the distribution network at certain times and in certain locations. In most cases, DNSPs have addressed these constraints (or potential constraints) by augmenting the network to increase its capacity. This has resulted in substantial increases in their capital expenditure and reduced their asset utilisation. (For example, 10 per cent of EnergyAustralia's network capacity is used for less than one per cent of the time.)

The Tribunal is concerned about the efficiency of this approach, and the effect it is having on the cost of electricity for end users. Its 2002 inquiry into demand management[107] found that demand management options can be a more cost-effective way to relieve network constraints, and can improve capital efficiency and provide flow-on benefits to end users in the form of lower costs. However, DNSPs have undertaken few demand management activities in the current regulatory period. The 2002 inquiry also identified a range of barriers to the use of demand management options, some of which related to the current regulatory framework of network pricing.

In determining the new regulatory framework for 2004–09, the Tribunal has aimed to ensure that these regulatory barriers are removed, and to neutralise the potential disincentive for demand management created by the change to a weighted average price cap form of regulation (which links revenue to volumes sold). It considers that its final decisions represent a generous treatment of demand management activities. This generosity is warranted, at least in the short term, to help overcome the barriers to the greater use of demand management solutions in supplying network services and to support the emergent market for these solutions.

However, in the medium to longer term, as demand management becomes 'business as usual' for DNSPs, the Tribunal believes it will be more appropriate to treat demand management costs in the same manner as other costs.[108] For example, it considers it reasonable to expect that at the next regulatory reset in 2009, the DNSPs' forward-looking expenditure profiles will incorporate an appropriate mix of demand management and network build solutions, representing the least cost approach to meeting expected demand. If this is the case, the notional revenue requirements for each DNSP will reflect this lower cost mix, so an on-going pass-through of demand management costs or foregone revenue will not be appropriate. It intends to examine this issue closely at the next regulatory reset.

In addition, while the Tribunal believes its determination is an important step in promoting demand management, this determination will not overcome all the barriers. As the Tribunal has noted previously, the development of an effective market for demand management solutions in NSW will require action by all those involved in the electricity industry. The DNSPs must seek out opportunities to use demand management options to reduce their operating and capital costs, and improve their planning processes and internal cultures to

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107 IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services - Final Report,* Review Report No. Rev02-2, October 2002.

108 This is in line with the view put forward by SKM in its report to the Tribunal, *Avoided distribution costs and congestion pricing for distribution networks in NSW*, November 2003.

ensure that these options are well integrated into their planning processes. Retailers, customers, service providers and Government also have important roles to play.[109]

The Tribunal's final decisions in relation to the treatment of demand management are set out below. The issues raised by stakeholders in response to the draft decisions, the Tribunal's considerations in making its final decisions, and the implications of these decisions are also discussed.

8.1 Final decisions

The Tribunal has decided that it will introduce a D-factor into the weighted average price cap control formula that allows DNSPs to recover:

- ***approved non-tariff-based demand management implementation costs, up to a maximum value equivalent to the expected avoided distribution costs***
- ***approved tariff-based demand management implementation costs***
- ***approved revenue foregone as a result of non-tariff-based demand management activities.***

The D-factor will be calculated using the following formula:

$$D_{t+1} = \frac{DM\ Cost\ Pass\ Through\ Amount_{t+1}}{SRR_t - AF\ Revenue_{t\text{-}1}} - \frac{DM\ Cost\ Pass\ Through\ Amount_t}{SRR_{t-1} - AF\ Revenue_{t\text{-}2}}$$

Where:

D_{t+1}	**is the D-factor to be included in the price control formula for Year *t+1***
AF Revenue $_{t-1}$	**is the amount approved by the Tribunal for recovery by the DNSP of foregone revenue in Year *t-1***
AF Revenue $_{t-2}$	**is the amount approved by the Tribunal for recovery by the DNSP of foregone revenue in Year *t-2***
DM Cost Pass Through Amount $_{t+1}$	**is the DM Cost Pass Through Amount calculated for the DNSP for the Year *t+1* — the sum of demand management implementation costs and foregone revenue incurred in Year *t-1*, as approved by the Tribunal**
DM Cost Pass Through Amount $_t$	**is the DM Cost Pass Through Amount calculated for the DNSP for the Year *t***
SRR_t	**is the smoothed revenue requirement for the DNSP for the Year *t***
SRR_{t-1}	**is the smoothed revenue requirement for the DNSP for the Year *t-1***

109 See IPART, *Inquiry into the Role of Demand Management in the Provision of Energy Services - Final Report*, Rev02-2, October 2002, for possible steps these groups could take.

The Tribunal has also decided to:

- **treat DNSP rebates and payments for load reduction as negative prices under the weighted average price cap**
- **establish a working group to examine DNSP network planning processes**
- **establish a working group to develop a methodology for assessing the economic prudence of energy loss management investment**
- **establish a working group on the calculation of distribution revenue foregone as a result of demand management activities**
- **accommodate a Government demand management fund, if introduced.**

8.2 Summary of responses to draft decisions

The Tribunal set out its draft decisions in relation to demand management in Chapter 7 of its draft report[110] and in a subsequent discussion paper on the regulatory treatment of demand management.[111] The key components of these decisions were to:

- establish a regulatory framework that neutralises the disincentives for DNSPs to undertake demand management by:
    - establishing the cost building blocks on which DNSPs' notional revenue requirements are based using pre-demand management values and excluding demand management costs
    - allowing DNSPs to pass through demand management costs incurred during the regulatory period, up to a maximum value equivalent to the avoided distribution costs
    - allowing DNSPs to recover foregone revenue as a result of demand management projects during the regulatory period
    - recovering demand management costs and foregone revenue by way of a D-factor in the weighted average price cap formula
- encourage DNSPs to undertake congestion pricing trials
- treat rebates and payments for load reductions as negative prices under the weighted average price cap
- establish working groups to:
    - examine the treatment of demand management in network planning processes and the implications of the Tribunal's regulatory framework
    - develop an appropriate method for valuing energy loss management investments.

It received a range of submissions in response to these draft decisions. In general, most welcomed the fact that the Tribunal had sought to address the disincentives to demand management inherent in the weighted average price cap form of regulation. However, several raised concerns about the Tribunal's approach. These concerns included that:

- ***The Tribunal should allow DNSPs to recover 'learning by doing' or R&D type expenditures.*** EnergyAustralia, EUAA/EAG and the Total Environment Centre

110 IPART, *NSW Electricity Distribution Pricing 2004/05 to 2008/09 - Draft Report*, OP-18, January 2004.

111 IPART, *Treatment of Demand Management in the Regulatory Framework for Electricity Distribution Pricing 2004/05 to 2008/09 - Draft Decision*, OP-20, February 2004.

argued that the Tribunal should allow this kind of expenditure as it is necessary for DNSPs to improve their knowledge about which types of demand management project are effective and which types are not. This knowledge would reduce the perceived riskiness of demand management and lower barriers to demand management. They also pointed to overseas experience, which suggests that successful demand management can result from pilot studies conducted with regulatory support.

- ***The framework should not be restricted to non-tariff measures.*** Integral Energy[112] and EnergyAustralia[113] raised concerns about whether the Tribunal's framework would hinder the introduction of tariff-based demand management measures. Other submissions expressed concern that implementation costs associated with tariff-based measures may not be recoverable under the Tribunal's framework.
- ***The recovery of demand management costs is uncertain towards the end of the regulatory period.*** Several DNSPs commented that under the Tribunal's proposed approach, the recovery of costs incurred in the last two years of the regulatory period was not certain, as they would need to be recovered in the first two years of the following regulatory period (commencing in 2009).
- ***The framework should span more than one regulatory period.*** In its draft decision, the Tribunal signalled that it expected that the regulatory treatment of demand management would be less generous in the future. Several submissions argued that a longer term approach is required, particularly in light of long lead times associated with some demand management projects.
- ***The approach to calculating the foregone revenue needs to be clarified.*** Some submissions argued that the process for calculating the adjustment for foregone revenues needed to strike a balance between protecting customers from bearing costs in excess of the actual revenue foregone, and imposing administration and compliance costs on DNSPs that might limit the incentive to undertake demand management activities.
- ***The D-factor should be outside the price limits on network tariffs.*** EnergyAustralia and the Energy Networks Association argued that the Tribunal's limits on price movements may restrict the ability of DNSPs to recover the revenue associated with the D-factor, and that the D-factor should not be subject to price limits.[114]
- ***The outcomes for customers need to be explained.*** The joint EUAA/EAG submission asked that the Tribunal clearly explain the expected impact on customers of its proposed approach in relation to demand management. Other submissions[115] raised concerns about the limited sharing of benefits of demand management solutions with end users.
- ***The Tribunal has not gone far enough in supporting and encouraging demand management.*** Several submissions[116] argued that the Tribunal should more explicitly encourage demand reductions by end-users, particularly small customers with volatile loads (such as those who run air conditioners). The Total Environment Centre suggested that the Tribunal should earmark 25 per cent of growth-related capital

112 Integral Energy submission, 5 March 2004, p 47.
113 EnergyAustralia submission, 5 March 2004, p 66.
114 EnergyAustralia submission, 5 March 2004, p 45.
115 For example, PIAC submission, March 2004, p 3, and AGL ES&M submission, March 2004, p 2.
116 For example, EUAA/EAG submission, March 2004, p 32, and EMRF submission, March 2004, p 2.

expenditure for demand management, on a 'use it or lose it' basis.[117] The joint EUAA/EAG submission suggested that the Tribunal should promote the use of automatic two-way communication and load control infrastructure, and provide incentives for customers to invest in this technology. Origin Energy argued that demand management incentives should be accessible to retailers.[118]

8.3 Tribunal's considerations in making final decisions

In making its final decisions in relation to demand management, the Tribunal carefully considered all stakeholder responses to its draft decisions. Its considerations in relation to each of these decisions are explained below.

8.3.1 DNSPs can recover non-tariff-based demand management implementation costs

The Tribunal has decided that it will allow DNSPs to pass through the costs associated with implementing non-tariff-based demand management activities. The costs passed through must be approved by the Tribunal, and are limited to a maximum value that is equivalent to the avoided distribution costs expected to result from the demand management activities. Non-tariff-based demand management implementation costs are the costs incurred by DNSPs in changing the behaviour of end-users, using instruments other than tariffs, to reduce end-use demand for electricity or affect the timing or source of consumption. They include, for example, the administrative cost of running energy efficiency programs, education or information costs, and the cost of providing incentives to participants.

As a result of this decision, the Tribunal has not included any allowance for these costs in the cost building blocks on which the DNSPs' notional revenue requirements are based. This is necessary to avoid double counting of these costs. The Tribunal will not allow the pass through of costs that have already been included in the operating and capital expenditure estimates used to develop the cost building blocks—for example, the cost of investing in load control infrastructure on the DNSPs network. The Tribunal has also asked DNSPs to provide the capital and operating costs on a pre-demand management basis—that is, excluding the impact of demand management projects that they expect to undertake during the 2004-09 regulatory period, allowing the DNSPs to retain the benefit from these projects.

Pass through of non-tariff demand management implementation costs allowed

In principle, the Tribunal believes it would be appropriate for DNSPs to fund non-tariff demand management implementation costs out of the cost savings that arise from the deferral of capital expenditure that results from the demand management projects, rather than passing through these costs to end users. Where the deferral benefits accrue within a regulatory period, these cost savings are retained in full by the DNSP and so would be available to it to cover the demand management implementation costs.

117 TEC submission, March 2004, p 2.
118 Origin Energy submission, March 2004, p 5.

However, this may not be the case where the deferral benefits accrue across regulatory periods (that is, where costs are incurred in one regulatory period but the capital expenditure that is deferred was expected to occur in subsequent regulatory periods). This situation is likely to occur when demand management activities are undertaken towards the end of the regulatory period. The benefit to the DNSP of deferred expenditure will therefore depend on how the expenditure is treated at the subsequent regulatory reset. If building block costs were established on the basis of the actual timing of expenditure (that is, post demand management), then the benefit derived from the demand management project would be transferred to customers. This could lead to a situation where the financial cost to the DNSP exceeds the financial benefits to it, creating a disincentive for the DNSP to undertake the demand management.

The Tribunal considers that this issue is particularly relevant in the 2004-09 regulatory period, as even if DNSPs respond to the incentives for demand management provided in this determination, it is likely to be some time before they get demand management projects going. Therefore, ideally, it would maximise these incentives by committing to allow DNSPs to keep any deferral benefits at the next regulatory reset in 2009. It could do this by committing to allow capital expenditure in the 2009 regulatory period to be included in the building block costs at its pre-demand management profile (as it has decided to do in the 2004-09 regulatory period), or to allow the cost building blocks in the 2009 regulatory period to be adjusted to reflect the amount of avoided distribution costs.

However, whether such an adjustment should be made is an issue for the regulator at the next regulatory reset. The Tribunal does not have the jurisdiction to make a binding commitment on future regulators. This situation precludes it adopting a multi-period approach, as some stakeholders proposed.

The Tribunal considers that this issue represents a significant regulatory barrier to demand management in the short term, particularly given the emergent nature of the market for demand management solutions. It explored options for bringing forward the cost savings that arise from the deferral of capital expenditure by including them in the allowance for the 2004-09 regulatory period, but found this approach would be administratively complex and costly, and would likely lead to distortions in prices in this regulatory period. It has therefore aimed at neutralising the financial disincentives to DNSPs by allowing them to recover demand management implementation costs (and by compensating them for any revenue lost during the current regulatory period).

The Tribunal recognises that this decision on the pass through of non-tariff demand management implementation costs over compensates DNSPs for these costs in situations where the deferral benefits created in the 2004-09 regulatory period are sufficient to cover demand management costs. It acknowledges that this has certain disadvantages in terms of the signals sent for efficient demand management. However, it has weighed these disadvantages against the potential benefits of supporting demand management where the benefits accrue across regulatory periods, and has decided to err on the side of supporting the development of demand management. The Tribunal considers that it is more likely that deferral benefits will accrue across regulatory periods.

Pass through of non-tariff demand management costs limited to an amount equivalent to the value of expected avoided distribution costs

The Tribunal has decided that it is appropriate to limit the pass through of non-tariff demand management implementation costs to a maximum amount that is equivalent to the avoided distribution costs expected to result from that demand management project. It considers its regulatory treatment should support only efficient demand management projects — that is, those that generate a net cost saving. It does not consider that it is appropriate for customers to fund demand management costs in excess of the avoided distribution costs.

To recover the full implementation costs of any demand management project, the DNSP will be required to demonstrate that these costs in present value terms are less than or equal to the avoided distribution costs expected to result from the project. This should not be an onerous requirement, as DNSPs are likely to undertake this analysis as part of the standard process for developing a business case for demand management options.

The Tribunal will allow recovery of demand management implementation costs on an annual basis. The estimate of the avoided distribution costs used to cap the pass through of these costs for a particular project will be held constant in real terms at its initial value. The initial value will be the value the DNSP submits to the Tribunal in the first year it claims the pass through of these costs. If the project is implemented over several years, the DNSP will be able to claim the pass through of costs incurred each year until the total amount claimed reaches the expected avoided distribution cost amount in present value terms.

Fixing the cap at the *expected* avoided distribution cost amount should also reduce the risks to DNSPs should a project fail to deliver the expected deferral benefits. For example, EnergyAustralia noted that if a DNSP undertook a demand management project but failed to sign up enough demand reduction to justify the deferral of capital expenditure, it would incur both the demand management costs and the capital expenditure. While the Tribunal does not have full details of the project EnergyAustralia has in mind, it expects that in such circumstances the DNSP would be able to pass through the demand management costs on the basis that there was a demonstrated expected deferral if the project had been successful.

No explicit recovery of 'learning by doing' costs allowed

The Tribunal has decided not to allow an explicit recovery of costs associated with 'learning by doing' demand management projects, as proposed by some stakeholders. Its final decision means that DNSPs will only be able to recover the costs of such projects where they are able to demonstrate that there is an expected deferral benefit that exceeds these costs.

As it stated in its draft report, the Tribunal is of the view that it is inappropriate for customers to bear the costs of knowledge-building or experimental demand management activities—rather, this is a role for government or the DNSPs themselves. It considers that the Government's proposed demand management fund would be an appropriate source of funding for this type activity. The Tribunal notes EnergyAustralia's concerns about whether DNSPs would be able to access this demand management fund, given that the Tribunal's 2002 inquiry recommended such a fund be used to provide for energy efficiency programs. The Tribunal supports the development of a demand management fund that allows funding for both energy efficiency and wider network demand management programs.

No recovery of costs funded from other sources

The Tribunal has decided that costs associated with demand management activities that have been funded through other sources—such as the CBD demand management fund or the Government's proposed demand management fund—will not be passed through. It is not appropriate for customers to bear costs that have already been recovered from other sources.

8.3.2 DNSPs can recover tariff-based demand management implementation costs

The Tribunal has decided that it will allow DNSPs to pass through Tribunal-approved implementation costs associated with introducing a new tariff-based demand management initiative, without requiring them to quantify the avoided distribution costs through deferral of expenditure. These tariff-based demand management implementation costs include the costs of installing interruptibility technology to allow remote control of air conditioners in support of the introduction of a new controlled load tariff.

The Tribunal has indicated support for DNSPs' efforts to introduce voluntary tariffs that better reflect the cost of consumption when networks are congested, such as controlled load air conditioning tariffs. The Tribunal considered the concerns raised by Integral Energy and EnergyAustralia that the Tribunal's draft decision may have meant that DNSPs would not be able to recover the costs associated with introducing this kind of tariff. This is because it is difficult to ascribe avoided distribution cost benefits to general tariff reforms, as these are likely to have a system-wide impact on network demand.

The Tribunal considers it would be unfortunate if tariff initiatives that address key cost drivers such as air conditioning load were stifled through the Tribunal's regulatory treatment of demand management costs. For this reason, it has decided to allow DNSPs to pass through efficient incremental implementation costs for tariff-based demand management initiatives in limited circumstances without requiring them to quantify the expected avoided distribution costs. These pass through costs are restricted to the installation of equipment at the customer's premises that control the time at which electricity is consumed. This pass through will be restricted to the introduction of new tariffs or new tariff components (that is, not reflected in the tariffs that are in place in 2003/04 financial year). The Tribunal will only allow the pass-through of incremental costs that have not already been reflected in the operating and capital expenditures used to develop the cost building blocks. The Tribunal will not allow the pass through of costs incurred by the DNSP in developing the tariff-based demand management initiative or metering costs.

DNSPs seeking the pass through of tariff based demand management implementation costs will be required to:

- demonstrate the objective of the tariff roll-out is to affect end-user behaviour
- detail the nature of the demand management costs and demonstrate their efficiency
- demonstrate that the demand management costs are necessary to achieve the objective of the tariff roll-out
- demonstrate that the demand management costs are incremental to, the cost building blocks and have not already been included in the operating and capital expenditure projections used to develop the cost building blocks.

8.3.3 DNSPs can recover revenue forgone as a result of non-tariff-based demand management activities

The Tribunal has decided to allow DNSPs to recover revenue foregone as a result of non-tariff-based demand management activities. The recovery of this foregone revenue is subject to Tribunal approval of the estimated amount. Where a demand management project results in reductions in revenue that extend beyond the end of that project, the DNSP may apply to recover the foregone revenue each year after the end of the project, up until the end of the regulatory period. After this time, any impact on sales volumes as a result of the demand management should be incorporated in demand forecasts for the subsequent regulatory period.

Recovery of foregone revenue from non-tariff demand management activities appropriate

One of the Tribunal's main objectives in making its final decisions on the treatment of demand management was to allow DNSPs to retain the benefits of any net network cost savings they generated through demand management initiatives. Under the weighted average price cap, X-factors are fixed for the length of the regulatory period. This means that the benefits of any cost savings are not passed through to customers through lower prices during the regulatory period. This is a key feature of incentive regulation, and encourages DNSPs to seek out these savings through demand management or other means.

However, the weighted average price cap also links revenues to sales volumes. This means that if a demand management project leads to lower sales volumes and therefore lower revenue, it can limit the ability of DNSPs to recover their notional revenue requirements. This creates a financial disincentive for them to undertake demand management. The Tribunal considers that it is appropriate to neutralise this disincentive by allowing DNSPs to recover this foregone revenue for non-tariff demand management activities.

In the case of tariff-based measures, foregone revenue associated with the introduction of concessional tariffs (for example, offered by the DNSP to attract customers to a controlled load-type tariff) will be recovered via the weighted average price cap. Lower tariffs will allow the DNSP to increase other tariffs within the constraints of the weighted average price cap formula. The Tribunal has decided not to provide for the recovery of foregone revenue as a result of quantity reductions related to tariff-based demand management activities. The Tribunal considers that the administration costs of accurately estimating and verifying the amount of foregone revenue across a diverse range of customers would, in general, be too high to justify the benefits in terms of providing incentives for demand management.

Foregone revenue to be calculated using direct assessment approach

The Tribunal recognises that accurately calculating the amount of revenue foregone as a result of demand management will be difficult. Many factors affect energy consumption levels, and the impact of demand management cannot be precisely separated from the impact of other factors. However, it considers the direct assessment approach recommended by its consultant, SKM, is an appropriate method.[119]

119 SKM, *Avoided distribution costs and congestion pricing for distribution networks in NSW*, November 2003, p 80.

With the direct assessment approach, the DNSP estimates the impact of a particular project on the level of demand/consumption in its area of operation, and provides quantitative evidence to support this estimate. The Tribunal is attracted to this, because it requires the DNSPs to be accountable for their claims of foregone revenue. It also considers it reasonable because, as SKM's report noted, DNSPs that currently make payments or provide incentives as part of a demand management project should already be estimating the expected impacts on demand, and then evaluating actual impacts to determine whether the demand management has been effective in reducing demand. Further, DNSPs' contracts with demand management providers are likely to include a performance-based element that includes some measurable impact on consumption. This is the case with Integral Energy's Castle Hill project, where payments to SEDA are contingent on measured reductions in demand.

The Tribunal considered EnergyAustralia's proposal that avoided distribution costs be used as a proxy for foregone revenue. The DNSP argued that this approach would be administratively simpler to apply, and provides a point-in-time estimate that can be incorporated into prices without lag.

The Tribunal recognises that this approach could involve lower administration costs for DNSPs. However, it is not convinced that it is suitable. For example, it is not clear how good a proxy avoided distribution costs is for foregone revenue — in particular, would it tend to systematically over or under-recover revenue? Also, using this proxy would mean that foregone revenue is recovered prospectively, whereas the Tribunal prefers a retrospective approach to the recovery of both foregone revenue and demand management implementation costs (see section 8.3.4). With a prospective approach, customers would be required to bear the costs of compensating DNSPs for the revenue they expect to forego, even when demand management projects are not successful and so do not affect their energy sales volumes and revenue. The Tribunal does not consider this appropriate.

Precise methodology to be developed by a working group

Both the Tribunal and the DNSPs have limited experience of the type of demand management projects that might occur during the 2004-09 regulatory period. The Tribunal therefore considers it is not appropriate to specify a precise methodology for calculating foregone revenue, but to allow the DNSPs to submit their estimates and methodologies to it for assessment. However, it does consider it appropriate to establish a set of broad principles to guide DNSPs in calculating foregone revenue.

These broad principles could include the following:

- there should be a well-defined group of customers whose consumption is impacted by the demand management project
- the link between the demand management project and affected customer should be documented
- estimates should be made with reference to quantitative estimates of reductions in volumes — for example, based on reduction in metered consumption, reductions in number of appliances, hours or time of use of machinery etc
- estimates may be derived with reference to a sample of affected customers — a full audit of customers is not required.

The Tribunal has decided not to finalise the guidelines at this time, as several stakeholders indicated that they had not had sufficient time to consider the guidelines proposed in the draft decision. Rather, it has decided to establish a working group so they can be developed with cooperation from stakeholders. As the DNSPs' and its own experience and knowledge of demand management improve, the Tribunal expects to revisit these guidelines during the regulatory period to ensure they remain appropriate.

8.3.4 Demand management costs and foregone revenue will be recovered through a D-factor mechanism

The Tribunal has decided that demand management implementation costs and foregone revenue as discussed above will be recovered through a D-factor component in the weighted average price cap formula. This will be calculated as:

$$D_{t+1} = \frac{DM\ Cost\ Pass\ Through\ Amount_{t+1}}{SRR_t - \mathrm{A}F\ R\mathrm{evenue}_{\mathrm{t\text{-}1}}} - \frac{DM\ Cost\ Pass\ Through\ Amount_t}{SRR_{t-1} - AF\ R\mathrm{evenue}_{\mathrm{t\text{-}2}}}$$

Where:

D_{t+1}	is the D-factor to be included in the price control formula for Year *t+1*
AF Revenue $_{t-1}$	is the amount approved by the Tribunal for recovery by the DNSP of foregone revenue in Year *t-1*
AF Revenue $_{t-2}$	is the amount approved by the Tribunal for recovery by the DNSP of foregone revenue in Year *t-2*
DM Cost Pass Through Amount $_{t+1}$	is the DM Cost Pass Through Amount calculated for the DNSP for the Year *t+1* — the sum of demand management implementation costs and foregone revenue incurred in Year *t-1*, as approved by the Tribunal
DM Cost Pass Through Amount $_{t}$	is the DM Cost Pass Through Amount calculated for the DNSP for the Year *t*
SRR_t	is the smoothed revenue requirement for the DNSP for the Year *t*
SRR_{t-1}	is the smoothed revenue requirement for the DNSP for the Year *t-1*

This formula is intended to allow DNSPs to recover additional revenue equivalent to the demand management pass-through amounts by raising DUOS prices. This increase is determined by the D-factor, which represents the allowed proportionate real increase in DUOS prices over and above that allowed by the X factor. The Tribunal has decided to base the calculation of the D factor on the smooth revenue requirements to provide a high degree of transparency in the calculation of the D-factor. In addition, the smoothed revenue requirement is based upon the growth projections discussed in chapter 4, representing the most likely growth scenario for the DNSPs over the regulatory period. The Tribunal considers that a significant advantage of the D-factor approach is that it makes explicit the adjustments to the weighted average price cap to correct for the potential disincentives to demand management that exist under a weighted average price cap form of regulation.

The D-factor formula represents a change from the draft decision to avoid over-recovery of allowed costs due to the cumulative nature of price changes under the D-factor approach. The formula now has an additional term (the second term) which removes the effect of the previous year's pass through amount from the prices. If this additional term were excluded, there would be a cumulative impact on prices and the DNSP would continue to recover implementation costs, for example, over all remaining years of the regulatory period.

The other minor change from the draft decision is that the smoothed revenue requirement is for Year *t*, rather than Year *t+1*. This is appropriate because at the price change, the equation is asking how much do prices need to rise from Year t levels in Year *t+1* in order to recoup the demand management costs. By including the smooth revenue requirements for Year *t+1*, the D-factor is understated since this value already accounts for the effect of the X-factor in Year *t+1* and inappropriately inflates the base from which the D-factor is calculated. The draft decision also deducted DM Costs from the denominator, which would have tended to over-state the required D-factor since demand management implementation costs do not affect the level of revenue collected by the DNSP.

The Tribunal's approach means that demand management costs and foregone revenue will be recovered on a retrospective basis, with a two-year lag. (For example, costs and revenue foregone in 2004/05 would be recovered through prices in 2006/07.) This lag is necessary, as prices for 2005/06 have to be approved by the Tribunal before the end of 2004/05. The demand management costs and foregone revenue will be carried forward at the DNSP's allowed rate of return. The Tribunal expects that demand management costs and foregone revenue occurring in 2007/08 and 2008/09 would be recovered in the following regulatory period via a correction factor, as allowed for under the clause 6.10.5(d)(8) of the Code.

The Tribunal will also allow DNSPs to defer recovery of approved foregone revenue and demand management implementation costs until later years if the first term in D-factor is less than 0.001. This deferral is aimed at ensuring that pass-through amounts are large enough to be reflected in the change in average prices allowed under the weighted average price cap. No deferral will be allowed in the final year of the determination.

DNSPs seeking the Tribunal's approval for the pass through of demand management costs and foregone revenue must apply to the Tribunal by 1 February each year. The information that DNSPs are required to submit is outlined in Clause 11 of the legal determination.

Box 8.1 provides an illustrative example of these arrangements.

Box 8.1: Example of D-factor calculation

In this example, assume that the DNSP, Generic Energy, implements a non-tariff demand management project in 2004/05 costing $400,000 and a tariff-based demand management project costing $50,000. The non-tariff demand management project leads to a reduction in the level of sales of 4000 MWh, resulting in the deferral of a $10,000,000 capital expenditure project by 1 year from 2005/06 to 2006/07. For simplicity, the reduction in sales is assumed to affect sales in 2004/05 only. In the absence of the non-tariff demand management project, Generic Energy would have sold 10,000 GWh in 2004/05. Generic Energy has only one tariff class which had a price of 2.85 cents/kWh in 2004/05. All costs are assumed to occur at the beginning of the year.

In line with Clause 11 of the Tribunal's determination, Generic Energy applies for the pass through of demand management costs and foregone revenue in its prices for 2006/07. In its application to the Tribunal, which it submitted on 30 January 2006, Generic Energy submitted the following financial information:

- Non-Tariff Demand Management Costs of $400,000
- Tariff Demand Management Costs of $50,000
- Estimated Foregone Revenue of $114,000 (calculated as 4000 MWh*2.85 cents/kWh)
- Estimated Avoided Distribution Costs of $598,300 (Calculated as the difference in present value of $10m expenditure in 2004/05 and the present value of $10.25m in 2005/06 as a result of the deferral, assuming a nominal discount rate of 9.7% — the DNSP's nominal rate of return as allowed by the Tribunal. Capital expenditure is slightly higher in 2005/06 reflecting the effect of inflation of 2.5% on costs.)
- Holding costs of $109,416 calculated in accordance with Clause 11.1(g). (Calculated as the sum of demand management costs and Foregone Revenue — $564,000 — multiplied by the nominal rate of return of 9.7% multiplied by the number of years between expenditure [start of 2004/05] and the commencement of 2006/07 financial year —2 years.)

The Tribunal reviewed Generic Energy's calculations and supporting documentation and approved the amounts it submitted. The Tribunal also checked whether the Non-Tariff Demand Management Costs were less than the Avoided Distribution Costs and found they were, so it allowed the pass through of the full amount.

The DM Cost Pass Through Amount for Generic Energy for 2006/07 was therefore calculated at $673,416 (Calculated in accordance with Clause 11.4 — the sum of $400,000, $50,000, $114,000, and $109,416 — there was no deferred amount from 2005/06). Generic Energy checked whether it was eligible to defer the recovery of this amount in accordance with clause 11.5. It checked Annexure 12 of the determination and found that its smooth revenue requirement for 2005/06 (SRR_t) was $300,846,000. It found it was ineligible to defer the pass through as:

DM Cost Pass Through $\text{Amount}_{t+1}/(SRR_t\text{-AF Revenue}_{t-1})$ =$673,416/($300,846,000-$114,000)=0.002>0.001.

Generic Energy's D-factor for 2006/07 was then calculated as:

D_{t+1} = DM Cost Pass Through $\text{Amount}_{t+1}/(SRR_t\text{-AF Revenue}_{t-1})$ -- DM Cost Pass Through $\text{Amount}_t/(SRR_{t-1}\text{-AF Revenue}_{t-2})$
= $673,416/($300,846,000-$114,000) + 0 = 0.002

In the following year, Generic Energy had no demand management related costs that were incurred in 2005/06 so did not apply for the pass through of any amounts in 2007/08 prices. However, it is still required to calculate its D-factor for 2007/08. For 2007/08, Generic Energy's D-factor was calculated:

D_{t+1} = DM Cost Pass Through $\text{Amount}_{t+1}/(SRR_t\text{-AF Revenue}_{t-1})$ -- DM Cost Pass Through $\text{Amount}_t/(SRR_{t-1}\text{-AF Revenue}_{t-2})$
= 0 -- $673,416/($300,846,000-$114,000) = -- 0.002

The negative amount for the D-factor reverses the impact on prices from the previous year.

Retrospective recovery preferred as it is administratively simpler

Several submissions in response to the Tribunal's draft decision noted that the Tribunal's retrospective approach means DNSPs cannot be certain that they will be able to recover these costs in the last two years of the regulatory period. The Tribunal re-considered taking a prospective approach to reduce the uncertainty for DNSPs. However, it is of the view that as this would require periodic reconciliation and adjustments, it would be too complex administratively.[120] In addition, it would create an incentive for DNSPs to overstate their expected demand management costs and foregone revenue in the final two years of the regulatory period in the hope that there would be no reconciliation in the subsequent regulatory period. For these reasons, it decided a retrospective approach was preferred.

In terms of certainty of recovery, the Tribunal recognises that it cannot bind future regulators. However, it notes that DNSPs are legally entitled to recover approved demand management cost and foregone revenue under the 2004-09 determination. The Tribunal expects that this would represent a very strong basis for a carryover amount being incorporated into the next regulatory period, as allowed under the Code.

D-factor to be subject to price limits

The Tribunal has decided that there is no need for the D-factor to operate outside of the limits on price movements. Several submissions from DNSPs argued that these limits—which the Tribunal sets to restrict how much individual network tariffs can move—will prevent DNSPs from recovering demand management costs via the D-factor.

The Tribunal considered the DNSPs' arguments, and does not agree that the price limits will prevent them recovering demand management costs. The price limits work in concert with the Tribunal's Transmission Over and Unders Account arrangement that guarantees that DNSPs will be able to recover their transmission costs in addition to the allowed distribution notional revenue requirements over the regulatory period. In addition, the historical evidence suggests that the size of the D-factor will be small (see section 8.4.1), and is therefore unlikely to have a material impact on the timing of the recovery of transmission revenues. Further, there is a 'safety net' provision that allows the Tribunal to relax the limits on price movements in the event that there is an unexpectedly large accumulation in the unders and overs account balance.

8.3.5 Rebates and payments for load reduction will be treated as negative prices

Under the revenue cap form of regulation applied in the 1999-2004 regulatory period, rebates on network charges and DNSP payments for load reduction are included as negative revenue when calculating regulated revenue and compliance with side constraints on changes in network charges. The Tribunal has decided that under the weighted average price cap form of regulation for the 2004-09, these payments will be treated as negative prices. This treatment will allow DNSPs to increase other tariffs to recover the cost of the

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120 For example, one possible approach would be for DNSPs to nominate expected implementation costs and foregone revenue for the year. These amounts would be incorporated into the D-factor. Once the outcomes for that year are known, a reconciliation would take place and the difference between actual and allowed amounts would be calculated and deducted or added to the amount recovered for the coming year via the D-factor. This adjustment would need to occur with a two-year lag, given the timing of price approvals. There may also need to be some allowance for the opportunity cost of funds on differences between allowed and actual.

payments. It will have the same effect as the inclusion of the payments as negative revenue under the revenue cap arrangements in the 1999-2004 regulatory period.

8.3.6 A working group will be established to examine DNSP network planning processes

As the Tribunal's 2002 demand management inquiry identified, one of the major barriers to the greater use of demand management options is a culture within DNSPs that favours traditional engineering solutions. For this reason, the Tribunal's report on this inquiry recommended that it work with DNSPs and other stakeholders to develop planning processes that allow better consideration of demand management by DNSPs.

The Tribunal is of the view that there are significant benefits to be gained by improving DNSPs' network planning processes. For example, DNSPs face a difficult planning task in terms of providing sufficient capacity in their network to meet demand that is inherently uncertain over time. In some cases, they have augmented networks to meet an anticipated growth in demand, only to see that demand disappear as a result of dips in economic activity, leaving them with excess network capacity. One of the advantages of demand management projects is that they might allow DNSPs to defer network investments until demand conditions are more certain or established. The demand management project therefore has an 'option value' benefit. The Tribunal would like to work with DNSPs to ensure that this option value benefit is adequately reflected in their network planning processes, and to ensure that the regulatory framework recognises these benefits when assessing the prudence of capital expenditure.

There is also a need for the market to play a greater role in promoting demand management solutions. This requires DNSPs to embrace more open processes where they test the market through standard offers rather than relying on internal assessment processes.

To help capture these benefits, the Tribunal has decided to establish a network planning working group. The working group will involve members of the Tribunal's secretariat, DNSPs and other relevant stakeholders. Its objectives will be to:

- promote greater clarity in network planning processes as to the treatment of investment in non-network projects and demand management
- clarify how the regulatory framework assesses the prudence of investments in non-network projects and demand management
- identify any changes required to ensure the regulatory framework consistently assesses the prudence of investments in non-network projects and demand management
- identify options for encouraging more open processes that allow DNSPs to test the market for demand management solutions
- identify means of reflecting the option value benefits from demand management projects in project assessment and ensuring the regulatory framework recognises these benefits in assessing prudence.

It is expected that the working group will finalise a methodology soon after the commencement of the 2004-09 determination period, to provide the greatest amount of certainty for DNSPs faced with capital expenditure decisions. The results of the working group process that have implications for the regulatory framework will be submitted to the Tribunal for its consideration and published as a guideline.

8.3.7 A working group will be established to develop a method for assessing the value of loss management investments

As electricity passes through an electricity network, a certain amount of energy is lost as a result of the resistance of the network components. As a result, customers need to purchase greater quantities of electricity than they actually consume at their premises. Because customers rather than DNSPs bear these costs, the Tribunal has incorporated incentives in the regulatory framework for DNSPs to invest in loss management initiatives, by allowing them to roll into their prudent expenditure on loss management equipment into their regulatory asset base. This allows them to earn a return on and of these investments.

However, the DNSPs believe these incentives are not sufficient. For example, in its submission to the Tribunal's demand management inquiry, Integral Energy argued that because DNSPs do not bear the cost of higher losses, there is little incentive to invest in loss minimisation—and if they do, there is a risk that the optimisation process may remove these assets from their asset base.[121] In its submission to the distribution price review, Country Energy commented that the consultants who undertook Treasury's 1998 valuation of the DNSPs' assets had optimised out a number of loss reducing investments, and that the 1998 regulatory asset value should be adjusted upwards to take account of the value of these investments.

The Tribunal has decided not to make adjustments to the 1998 regulatory asset value in establishing the opening asset base for 2004 (see Chapter 5). It also notes that the investments Country Energy referred to were part of the pre-1999 asset base, and any adjustments allowing the DNSPs to earn a rate of return on and of these assets would not affect their utilisation. However, it is concerned about maintaining incentives for investing in loss reducing assets in the future. The treatment of expenditures to replace or augment existing loss reduction assets has implications for the incentives that DNSPs have for investing in these assets.

In its 1999 report to the Premier on pricing for electricity networks and retail supply,[122] the Tribunal supported the principle that the value of loss reductions should be taken into account when assets are rolled into the asset base. The Tribunal now re-affirms this position:

- prudent loss management investments will be rolled into the asset base
- economic loss management investment should not be optimised out of the regulatory asset bases.

121 IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services - Final Report*, Review Report No. Rev02-2, October 2002, p 65.

122 IPART, *Pricing for Electricity Networks and Retail Supply - Report*, Volume 2, Rev99-5.2, June 1999, p 152.

To assess the value of a loss management investment, the net present value of losses saved as a result of the investment need to be estimated. The Tribunal believes that, in principle, this value should be based on the Long Run Marginal Cost of generation. However, it recognises that this value is not directly observable in the market place and that a variety of estimates could emerge. A more pragmatic approach could be to value losses at an average of national electricity market pool prices for NSW. This could be an historical average based on observable data and would overcome the practical difficulties of deriving an estimate of Long Run Marginal Cost.

To help resolve this valuation issue, the Tribunal will establish a working group in 2004 to develop a methodology for assessing the economic value of loss management investment. This working group will seek to identify:

- an appropriate methodological framework for calculating the amount of energy loss avoided as a result of the investment, including any relevant avoided losses occurring on the transmission network
- an appropriate methodology for calculating the per kWh value of energy loss based on an observable historic average of pool prices
- how DNSPs could incorporate the estimates of the value of loss reductions into their capital expenditure planning assessment processes and what implications, if any, this has for the regulatory test applied by the Tribunal for assessing the prudence of capital expenditure.

The overarching objective of this working group will be to ensure that the DNSPs are able to follow a methodology for assessing the value of loss reduction investments that is consistent with the Tribunal's approach to assessing the prudence of these investments as part of the roll forward of the asset base. It is expected that the working group will finalise this methodology soon after the commencement of the 2004-09 determination period, to provide the greatest amount of certainty for DNSPs faced with decisions to replace or augment loss management assets. The Tribunal will publish the methodology as a guideline.

8.4 Implications and other comments

In reaching its final decisions on the regulatory treatment of demand management, the Tribunal also considered the likely impact of its decisions on customers, whether it should go further in providing incentives and support for demand management, and how best it can encourage the DNSPs to trial or introduce congestion pricing. These considerations are discussed below.

8.4.1 Impact for customers likely to be modest

The Tribunal's decision to allow DNSPs to pass through demand management implementation costs will affect electricity prices for end-users. It is difficult to accurately assess the size of this impact, given uncertainty over the likely future value of demand management projects. Only some of the DNSPs provided projections for demand management expenditures over the 2004-09 regulatory period. However, based on those that did, the impact is likely to be modest. For example, Integral Energy's April 2003 submission included an annual allowance of around $700,000, which is equivalent to around 0.004 cents/kWh, given expected sales over the 2004-09 regulatory period.

Historical levels of expenditure also suggest that potential customer impacts are likely to be modest. The Department of Energy, Utilities and Sustainability (DEUS) publishes the value of demand management expenditures reported by DNSPs. In the latest published year (2000/01), DNSPs reported demand management expenditures of approximately $7 million.[123] On sales of approximately 50,000 GWh, this equates to approximately 0.01 cents per kWh.

It should be noted that the DEUS data is not directly comparable to the costs that the Tribunal will allow DNSPs to pass through, since it includes learning by doing expenditures and load control investments, which are excluded from the pass through mechanism. As such the DEUS information may overstate the likely pass through amount — although the Tribunal would expect the amount of demand management undertaken to grow over time as the barriers to it are reduced.

The recovery of foregone revenue is expected to neutralise the impact of demand management on revenue. As such, customers as a whole would not be expected to pay higher charges. However, there is likely to be a distributional impact among customers. If a demand management project increases energy efficiency, those customers directly affected by it will benefit from lower bills as a result of lower consumption. However, any recovery of the DNSP's foregone revenue associated with the project is likely to be spread across its full customer base, as the DNSP would be allowed to increase general prices. This same effect occurs under the revenue cap form of regulation applied in the 1999-2004 regulatory period.

8.4.2 Provision of further incentives inappropriate

Some of the submissions in response to the draft report argued that the Tribunal should go further in supporting demand management. For example, the Total Environment Centre suggested that DNSPs should be given minimum expenditure requirements for demand management. The Tribunal believes that deciding whether or not such a measure should be introduced is a policy issue, and therefore the responsibility of the Government, not the role of the economic regulator. However, it notes that such an approach would be heavy-handed and not without some considerable disadvantages. Any policy consideration of these issues will need to carefully weigh potential benefits against potential costs.

The EUAA suggested that the Tribunal should promote the potential use of automatic, two-way communication and load control infrastructure, and also provide incentives for customers to invest in that technology. The Tribunal also considers that this is outside its role as the economic regulator. Rather it is a network planning issue, and therefore should rightly be left to the DNSPs. The Tribunal's role should be in developing a regulatory framework that provides incentives for DNSPs to make cost-minimising decisions. By allowing the DNSPs to retain the benefits of cost reductions, the Tribunal considers that its framework provides DNSPs with the incentive to undertake measures that reduce the peakiness of demand on their networks, including the measures promoted by EUAA such as cost reflective TOU-pricing, subsidies for high efficiency air-conditioning or appliances fitted with suitable technology to remotely control load[124] (if they are cost-effective). The challenge is for DNSPs to respond to these incentives.

[123] DEUS, *NSW Network Management Report, 2000-01*, May 2002.

[124] EUAA submission, March 2004, p 36.

The Energy Markets Reform Forum (EMRF) argued that the most fundamental shortcoming of the Tribunal's draft decisions was 'the absence of any incentive mechanism for major end-users to contribute to demand-management, especially during peak periods'. The Tribunal disagrees with this assessment. Its regulatory mechanism allows DNSPs to retain the benefits of capital deferral for at least the length of the regulatory period rather than return these savings to customers. These savings represent a source of funds that can be used to contract with end-users and other demand management providers, including retailers, in order to bring about deferral of capital and operating expenditure. It would also be a similar outcome to a situation where the Tribunal had included estimates of foregone revenue in the sales projections that supported the calculation of the X-factors.

8.4.3 DNSPs are encouraged to trial congestion pricing

The Tribunal supports the use of both price and non-price demand management measures to reduce growth in peak demand and thus relieve network capacity constraints. It believes that appropriately structured prices that signal the costs of network congestion can play an important role in assisting DNSPs manage emerging areas of network constraint.

By effectively signalling network costs, such congestion prices create an incentive for end-users to modify their energy use where or when network capacity is constrained. For example, this constraint might occur in particular geographical areas of the network or generally across the network at peak times. Congestion prices might therefore apply at particular locations or across the network at particular times of the day.

Although the available empirical evidence suggests that, in general, customers' consumption does not change much in response to price changes,[125] the experience of distribution businesses in other countries suggests that pricing signals supported by non-price measures can be very successful in limiting growth in demand. For example, SKM's report on congestion pricing cites a New Zealand example where the introduction of congestion pricing allowed a substantial amount of capital expenditure to be deferred—both at the distribution network level and in the transmission network.[126]

As outlined in Chapter 15, the Tribunal has adopted an alternative pricing methodology to the one set out in the Code. This approach makes DNSPs responsible for setting prices and making tariff changes (in line with pricing principles and other requirements). Thus, the onus is on DNSPs to ensure that their tariffs are structured in a manner that provides proper signals to customers as to the cost of their consumption on network costs. The Tribunal re-iterates its recommendation from its 2002 inquiry into demand management that DNSPs undertake trials of localised congestion pricing in regions of emerging constraint of the distribution network.[127]

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125 See, for example, chapter 6 of the Secretariat's discussion paper on inclining block tariffs — IPART Secretariat, *Inclining Block Tariffs for Electricity Network Services, Secretariat Discussion Paper,* DP64, June 2003.

126 SKM, *Reducing Regulatory Barriers to Demand Management: Avoided Distribution Costs and Congestion pricing for distribution Networks in NSW - Final Report*, November 2003, chapter 8.

127 IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services - Final Report*, Review Report No. Rev02-2, October 2002, p 68.

To assist them, the Tribunal has tried to ensure that the regulatory framework for the next regulatory period will provide sufficient flexibility for DNSPs to structure their prices in a cost-reflective way. Some DNSPs suggested that the limits the Tribunal placed on individual price movements (side constraints) in the 1999-2004 regulatory period created a significant impediment to tariff restructuring (see Chapter 14). The Tribunal is satisfied that the price limits on network tariffs set for the 2004-09 regulatory period provide sufficient headroom for DNSPs to undertake significant tariff restructuring — including trials of localised congestion pricing. This issue is discussed in Chapter 14.

9 CHARGES FOR MISCELLANEOUS AND MONOPOLY SERVICES

Miscellaneous services are 'non-routine' services related to the distribution of electricity. They include special meter readings, meter testing and disconnection for non payment. Monopoly services are those related to extensions, augmentations or connections to the network that only DNSPs can perform. For example, when a customer is required to pay for an extension to the network (that is, to make a capital contribution), the customer can choose to have the DNSP or an independent accredited service provider (ASP) perform the work.[128] However, to maintain the safety and integrity of the network, some of the services involved in this work can only be performed by DNSPs. These monopoly services include design checking, installation inspection and energising/de-energising the network.

As Chapter 3 discussed, the Tribunal considers miscellaneous and monopoly services to be prescribed distribution services. These services account for a small proportion of total distribution services revenue—typically around 2 per cent. For example, in 2002/03, the DNSPs generated only $14.3 million from miscellaneous services and $8.9 million from monopoly services (Table 9.1). Nevertheless, the charges for these services can have a significant impact on the individual customers who must pay them.

In making its decisions on regulating these services, the Tribunal has determined what services should be considered to be miscellaneous or monopoly services, what approach should be used to set charges for these services, and what level these charges should be set at. Its final decisions are set out below. The rest of this chapter provides an overview of the draft decisions and stakeholders' responses to these decisions, and explains the Tribunal's considerations in making its final decisions.

Table 9.1 Total DNSP revenue from miscellaneous charges and monopoly fees in 2002/03 (nominal dollars)

Revenue Source	Energy Australia	Integral Energy	Country Energy	Australian Inland	Total
Regulated Distribution Revenue	$825m	$534m	$529m	$19.3m	$1907m
Miscellaneous Charges	$0.6m	$7.6m	$5.7m	$0.4m	$14.3m
Monopoly Fees	$3.6m	$2.4m	$2.9m	$0m	$8.9m

Source: Regulatory accounts 2003.

9.1 Final decisions

The Tribunal has decided that it will continue to regulate miscellaneous services charges by determining an exhaustive list of maximum charges, and to regulate monopoly services by determining an exhaustive list of mandatory charges.

In addition, it has decided that the current maximum charges for miscellaneous services and mandatory charges for monopoly services shall increase by the change in CPI since

128 Capital Contributions are regulated under a separate Tribunal determination, *Capital Contributions and Repayments for Connections to Electricity Distribution Networks in New South Wales - Final Report*, Determination No.1 2002.

the last determination (approximately 17 per cent) via a once-only adjustment on 1 July 2004. No further changes will be permitted for the remainder of the regulatory period.

In relation to miscellaneous services, the DNSPs may only charge for the services listed in Table 9.2, and must not charge more than the amount shown in this table. This list differs from the list in the 1999 determination in that:

- **The charge for the miscellaneous service associated with establishing a new account at an existing premise has been deleted. The cost of this service is now to be recovered via DUOS charges.**
- **An after-hours reconnection charge of no more than $75 has been introduced. This charge can be applied when a customer requests reconnection outside normal working hours,[129] and is in addition to the applicable disconnection charge. This charge also applies where a customer requests a new connection outside business hours.**

In relation to monopoly services, the DNSPs may only charge for the services listed in Table 9.3, using the hourly rates shown in Table 9.4. Unless specified in Table 9.3, they must levy the charge shown every time they provide a monopoly service, regardless of whether they provide it to their contracting business or to an independent ASP.

The list of monopoly services differs from the current list in that:

- **A site establishment charge has been introduced. This charge must be applied when establishing a new account at a new premise.**
- **Over-time rates for monopoly services have been introduced. These rates can be applied when an ASP requests that the service be provided outside normal working hours. In these circumstances, the DNSP may charge up to 175 per cent[130] of the standard fee for that portion of the service performed outside normal business hours. Where the DNSP requires that the work be conducted outside normal business hours then standard rates will apply.**

The Tribunal has also decided that each DNSP shall include a specified amount of travelling time when calculating monopoly service charges that involve travel to inspect Level 1 ASP work, and charge this time at the R2b (Inspector) hourly rate. The amount for each DNSP is as follows:

- **EnergyAustralia: 30 minutes**
- **Integral Energy: 30 minutes**
- **Country Energy: 60 minutes**
- **Australian Inland: 90 minutes.**

In addition, the Tribunal has decided that in calculating the charge for recoverable works involving emergency repairs, a DNSP must use the following pricing principles:

- **it must not charge more than 110 per cent of the actual costs associated with the repairs, plus**

129 Normal working hours are between 7.30am and 4.00pm except on Saturdays, Sundays and Public Holidays.

130 This means that if the charge for the service for normal time is $100 then if the service is carried conducted after hours at an ASP's request the total charge is $175.

- **no more than 150 per cent of the actual labour costs associated with the repair, when calculated at the R2b (Inspector) hourly rate shown on Table 9.4.**

Table 9.2 Maximum Charges for miscellaneous services for the 5 years to 30 June 2009 (nominal $)

Miscellaneous Service	$
Special meter reading	$35.00
Meter test	$58.00
Supply of conveyancing information - desk inquiry	$29.00
Supply of conveyancing information – field visit	$58.00
Off-peak conversion	$47.00
Disconnection visit (acceptable payment received)	$35.00
Disconnection at meter box	$70.00
Disconnection at pole top/pillar box	$117.00
Rectification of illegal connection	$175.00
Reconnection outside business hours	$75.00

Note: Conditions relating to charges for miscellaneous services are provided in Annexure 3 at Clause 3.2.

Table 9.3 Charges for monopoly services for the 5 years to 30 June 2009 (nominal dollars)

Monopoly Service	Underground urban residential subdivision (vacant lots)	Rural Overhead Subdivisions and Rural Extensions	Underground Commercial and Industrial or Rural Subdivisions (vacant lots - no development)	Commercial and Industrial Developments	Asset Relocation Or Street Lighting
Design Information	Up to 5 lots $126 6 to 10 lots $189 11 - 40 lots $315 Over 40 lots $378	R2 per hour	R2 per hour	R2 per hour	R2 or R3 per hour (See para 4.2)
Design Certification	Up to 5 lots $63 6 to 10 lots $126 11 - 40 lots $189 Over 40 lots $252	1 - 5 poles $63 6 -10 poles $126 11 or more poles $189	Up to 10 lots $126 11 - 40 lots $189 Over 40 lots $378	R3 per hour	R2 or R3 per hour (See para 4.2)
Design Rechecking	R2 per hour	R2 per hour	R2 per hour	R3 per hour	R2 or R3 per hour (See para 4.2)
Inspection of Service Work (Level 1 work)	Grade: A / B / C per lot / per lot / per lot First 10 lots: $32 / $76 / $158 Next 40 lots: $19 / $44 / $95 Remainder: $6 / $25 / $44	Grade: A / B / C per pole / per pole / per pole 1-5 poles: $38 / $76 / $139 6-10 poles: $32 / $63 / $126 11+ poles: $25 / $44 / $95 (see para 4.2)	Grade: A / B / C per lot / per lot / per lot First 10 lots: $32 / $76 / $158 Next 40 lots: $32 / $76 / $158 Remainder: $32 / $76 / $158	R2 or R3 per hour	R2 or R3 per hour (see para 4.2)
Access Permit	Residential Subdivisions: $21.00 per lot combined fee	$935 maximum per access permit	$935 maximum per access permit	$935 maximum per access permit	$935 maximum per access permit
Substation Commissioning		$701 per substation (See para 4.2)	$701 per substation (see para 4.2)	$701 per substation (see para 4.2)	$701 per substation (see para 4.2)
Administration	Up to 5 lots $153 6 - 10 lots $204 11 - 40 lots $255 Over 40 lots $306	Up to 5 poles: $153 6-10 poles: $204 11 or more poles $306	R1 per hour (max 6 hours)	R1 per hour (max 6 hours)	R1 per hour
Notice of Arrangement	$153				
Re-Inspection (Level 1 and 2 work)	R2 per hour (maximum 1 hour per level 2 reinspection)				
Re-inspection (Service Provider)	$63. For the purpose of clause 2(b), a DNSP may charge a fee that is less than this fee, but not a fee that is more than this fee.				
Access	R1 per hour				
Authorisation	$126				
Inspection of Service Work (Level 2 work)	All Service connections: A Grade : $16 per NOSW B Grade: $26 per NOSW C Grade: $76 per NOSW (NOSW = Notification of Service Work)				
Site Establishment	$110				

Note: Conditions relating to charges for monopoly services are provided in Annexure 3 at Clause 4.2.

Table 9.4 Labour rates

Labour class	Hourly rate
Admin R1	$51
Design R2a	$63
Inspector R2b	$63
Engineer R3	$76

9.2 Summary of draft decisions and stakeholder responses

The Tribunal's draft report set out draft decisions in relation to miscellaneous and monopoly services that were largely the same as the final decisions. The key differences were that travelling time in relation to monopoly services could only be charged when the journey involved was more than 2 hours one way, and that pricing principles for recoverable works involving emergency repairs were not specified.

EnergyAustralia suggested that there should be provision for new monopoly services to be introduced during the regulatory period. In addition, some stakeholders were concerned about the decision to index miscellaneous and monopoly services charges by 17 per cent via a once-only adjustment. Integral Energy, EnergyAustralia and Country Energy claimed that the resulting charges do not reflect the costs involved in providing these services, and would lead to over use of these services. They argued that the charges should be indexed each year of the determination. EnergyAustralia was strong in its criticism, calling the decision the 'most egregious example of regulatory micro management' it had ever seen. The Public Interest Advocacy Centre (PIAC), on the other hand, opposed the increase on the grounds that it had not been sufficiently justified.

In relation to the list of miscellaneous services:

- The Energy & Water Ombudsman of NSW (EWON) and PIAC supported the deletion of an account establishment fee from this list. However, Country Energy opposed this amendment. Its main concern was that once this fee is deleted, holiday house owners might start to disconnect and reconnect these houses to avoid paying the service availability charge (SAC) while they are not in use.
- EWON was concerned about the introduction of an after-hours reconnection charge. It noted that currently, when a DNSP disconnects a customer it may do so at any time of the day until 3.00pm. This means that customers who are disconnected towards the end of the day have very little time to recognise that they have been disconnected, and make the necessary arrangements for reconnection before the end of the DNSP's normal working hours. It argued that customers should be given adequate time to arrange reconnection on the same day.
- Integral Energy raised a specific issue about special meter readings. It argued that the draft decision did not make it clear whether the DNSP is able to charge for this service every time it is necessary to revisit the property to read the meter.

In relation to monopoly services, Country Energy was concerned that the Tribunal had not provided for travel costs in setting the mandatory charges for these services. It stated that this would have a significantly larger impact on it than on other DNSPs, due to the greater distances its inspectors must travel.

9.3 Tribunal's considerations in making its final decisions

In making its final decisions, the Tribunal has carefully considered the views expressed by stakeholders. Its consideration in relation to each of these decisions is discussed below.

9.3.1 Miscellaneous and monopoly services to be regulated by determining an exhaustive list of maximum or mandatory charges

In the 1999 determination, the Tribunal established an exhaustive list of miscellaneous and monopoly services, and set a maximum fee for each miscellaneous service and a mandatory fee for each monopoly service.

To help it determine how miscellaneous and monopoly services should be set for the coming regulatory period, it established two consultation groups in December 2002. These groups—which included representatives from the DNSPs, PIAC, an energy retailer, EWON, MEU, National Electrical Contractors Association (NECA), and other accredited service providers—held four meetings over December 2002 to May 2003. Based on the outcomes of these meetings, it decided to continue the current regulatory approach for these services.

In response to a concern raised by EnergyAustralia, the Tribunal considered establishing a mechanism to enable the DNSPs to seek its approval to introduce a new monopoly fee if a change in government policy meant that work that was once contestable become a monopoly service. However, given that any likely revenue from possible new fees will be immaterial it therefore decided to set an exhaustive list for the entire period of the determination.

9.3.2 Charges to be indexed by cumulative CPI increases then held constant for the period of the determination

The Tribunal decided that the charges for miscellaneous and monopoly services will increase by the change in the CPI since the last determination—which is approximately 17 per cent—via a once-only adjustment on 1 July 2004, and then be held constant (in nominal terms) for the regulatory period. It believes this approach will result in broadly cost reflective charges, without creating complexity or reducing transparency.

During its review, the Tribunal considered several alternative options, including:

- **Setting individual prices changes for each miscellaneous charge and monopoly fee.** It found this approach could not be justified, because the DNSPs could not substantiate their claims in relation the increased costs of providing these services. In most cases, they provided estimates of these increases only, based on highly aggregated data.
- **Leaving charges set at current prices in nominal terms.** While the DNSPs did not provide detailed justification of cost increases, the Tribunal considered it unlikely that their costs in relation to miscellaneous and monopoly services would not increase at all between 1997 and 2009. This option would therefore have resulted in charges that where far from cost reflective, creating a cross subsidy from network tariffs to miscellaneous and monopoly services.
- **Increasing prices by the cumulative CPI increase of 17 per cent at the start of the regulatory period, then indexing them by the annual CPI throughout the regulatory period.** This option may have satisfied most of the DNSPs' concerns. However, the Tribunal considered that it would have reduced transparency in relation to these charges, especially for monopoly fees, as stakeholders would not know the exact

charge that applies for each service throughout the regulatory period. The Tribunal believes this level of transparency is important for monopoly service charges because of the implications for competition.

In addition, while the Tribunal considers it is important that the level of miscellaneous charges and monopoly fees broadly reflect the DNSPs' costs in providing these services, the Tribunal had to balance this goal against the benefits from a simplified approach, given the relatively small percentage of revenue involved as well as the fact that the data provided by the DNSPs was often highly aggregated.

9.3.3 Account establishment fee to be deleted from the list of miscellaneous services

Under the 1999 determination, DNSPs could charge an account establishment fee of $35 whenever a customer moved into new premises. The Tribunal has decided to delete this fee from the list of miscellaneous services. It considers that establishing account information is a normal part of doing business, and therefore the costs involved are more appropriately recovered through general distribution tariffs.

In making this decision, the Tribunal considered the arguments of EWON and PIAC that the account establishment fee impacts most heavily on low-income tenants. Its own analysis suggests that this is likely to be the case—it shows that on average, home owners move once every 5 years whereas tenants move once every 12 months.[131]

It also considered Country Energy's claim that deleting this fee will set up a perverse incentive for owners of holiday homes to disconnect their properties outside the holiday season, to avoid the fixed service availability charge during this time. However, it does not believe that this is likely, given the inconvenience to customers that this would involve and the low level of service availability charges compared to variable charges.

9.3.4 After hours reconnection fee to be added to list of miscellaneous services

Under the Energy Supply Regulations, when a DNSP decides to disconnect a customer for non payment of bills, it can do so up until 3.00pm. However, the regulations do not specify any time limits in relation to reconnecting such customers. The DNSPs' general practice is to reconnect on the same day as they disconnect if the customer makes suitable arrangements to pay their bill by 3.00pm. If the customer makes suitable arrangements after 3.00pm, they will reconnect on the next working day.

The Tribunal has decided to introduce an after hours reconnection fee, to make it easier for those customers who are disconnected for non payment and who make arrangements to pay their bill *after* ***4.00pm*** to be reconnected immediately.

EWON raised its concern that customers be given adequate time to arrange reconnection within working hours on the same day. However, the Tribunal considers that the appropriate way to address EWON's concern is through a change in the regulations. It notes that consideration of such a change is a matter for Government, not the Tribunal.

131 Australian Bureau of Statistics, Australian Housing Survey, 1999.

9.3.5 A site establishment fee to be added to the list of monopoly services

The DNSPs proposed that a charge for site establishment (new account at a new address) be added to the list of monopoly services. They stated that this service requires them to undertake a significant amount of work—for example, to supply contractors (Level 2 ASPs) with a new meter, collect accurate location details, coordinate with NEMMCO, assign a NMI and update network load data. The Tribunal accepts this argument, and has decided to add a charge for site establishment to the list of monopoly services and charges.

9.3.6 Overtime rates to be introduced for monopoly services

During its review of the regulation of monopoly services, the Tribunal became aware of some confusion about whether DNSPs could charge overtime rates for these services. It decided that DNSPs should be able to charge higher rates when they provide monopoly services outside normal business hours at the ASP's request. However, where the DNSP requires the service to be conducted outside normal business hours, standard rates will apply.

The Tribunal considers that this decision strikes an appropriate balance between ASPs' need to have monopoly services provided outside normal working hours to meet their own or the end-use customer's demands and the need to provide certainty and consistency in pricing. It decided that this overtime rate shall be a maximum of 175 per cent of the standard monopoly fee for that part of the service conducted after hours.

9.3.7 Travelling time charges to be based on average travelling time and the R2b (Inspector) hourly labour rate

In its draft determination, the Tribunal stated its intention to allow DNSPs to include travelling time when calculating monopoly services charges only when the journey involved was more than 2 hours one way. This decision was in line with the 1999 determination, in which the Tribunal stated that it considered a reasonable amount of travelling time to be a normal part of doing business.

The Tribunal has re-examined this decision in response to the concerns raised by Country Energy. It concluded that while there are no price signals attached to the current charges for travel time, there are costs. It considers that it is appropriate that these costs be recovered from the customers who use monopoly services rather than the general customer base. However, it also considers that some travel time is a normal part of doing business, and therefore some of the associated costs should be met by the DNSP.

Based on data provided by the DNSPs, the Tribunal calculated the average travel time for each DNSP's inspectors, and subtracted an appropriate allowance for travel time it considers to be a normal part of business. Based on this calculation, it has decided that each DNSP must include a specified amount of travel time when calculating the monopoly service charges that involve inspectors travelling to inspect Level 1 ASP work, and charge this time at the R2b (Inspector) hourly rate.

9.3.8 Pricing principles to be used when calculating fees for recoverable works involving emergencies

The wide variety in the work involved in this function means that it is not practical for the Tribunal to regulate recoverable works for emergencies through the exhaustive list of charges. Rather, it believes it is more appropriate to regulate these charges through the pricing principles approach.

It has decided when calculating charges for recoverable works for emergencies, the DNSPs must charge no more than:

- 110 per cent of the actual costs associated with the repairs, plus
- 150 per cent of total labour costs associated with the repairs, based on the R2b (Inspector) hourly rate.

The above principles apply 24 hours every day of the year.

10 PROVIDING INCENTIVES FOR SERVICE QUALITY

Throughout its review process, the Tribunal has emphasised its desire to provide more explicit incentives for service quality, particularly in light of the substantial amounts of capital expenditure that the DNSPs expect to devote to maintaining (and in some cases improving) levels of service on the network.

The Tribunal's final decisions on this issue are set out below. The rest of the chapter outlines its draft decisions and stakeholder responses to these decisions, and explains its considerations in making its final decisions.

10.1 Final decisions

The Tribunal has decided to introduce an integrated package of measures to provide incentives for service quality, consisting of the following components:

- **the collection and publication of performance statistics on service standards, covering service reliability, quality of supply and customer service**
- **a 'paper trial' S-factor, focusing on service reliability measures - the Tribunal has decided *not* to introduce monetary incentives for service quality during the 2004-09 regulatory period**
- **subject to Ministerial approval, an expanded set of Guaranteed Customer Service Standards, covering service reliability, quality of supply and some aspects of customer service.**

10.2 Summary of draft decisions and stakeholder responses

The Tribunal's draft decisions were the same as its final decisions, with one key exception. As well as introducing an S-factor in a paper trial form that focused on service reliability data from July 2004, the Tribunal proposed to introduce monetary incentives from July 2006. It argued that monetary incentives would:

- strengthen the incentives for service quality beyond those that could be provided by data collection and publication alone
- provide an explicit link between price and service quality
- allow lessons to be learned by regulator and DNSPs alike, which could allow an easier transition to a potentially more extensive scheme from 2009.

However, it put the view that monetary incentives should only be introduced from 1 July 2006, and then only for the *network as a whole*, due to current data availability and accuracy constraints. Chapter 6 of the draft report set out details of the S-factor formula, draft reliability targets provided by the DNSPs, and draft incentive rates.

In response to the draft report, stakeholders expressed general support for continuing to collect and publish service quality performance data, and for running a paper trial of an S-factor. But, while many stakeholders expressed support *in principle* for an S-factor, only a few respondents supported the draft decision to introduce *monetary* incentives. The DNSPs' arguments for not introducing or delaying the introduction of monetary incentives were as follows:

- **It would create the risk of perverse incentives.** DNSPs argued that a monetary S-factor based only on the performance of the network as a whole (the only viable option given current data constraints[132]) would provide an incentive for DNSPs to concentrate on 'easy wins', rather than improving the reliability of the worst performing parts of the network, which are often more difficult/costly to improve. They argued that these incentives were contrary to their stated intentions to focus reliability improvements work on the worst performing parts of the network.
- **Difficulties associated with annual performance variability.** Country Energy and Australian Inland noted that reliability performance can vary significantly from year to year, even after removing the effects of major storms and other third party events. As a result, a DNSP could receive an S-factor penalty or reward due to factors outside its control. They were also concerned about the potential adverse publicity if a DNSP's 'natural' year-to-year performance variations were reported and published against pre-set annual targets.
- **The difficulty of adjusting for data accuracy improvements.** Several DNSPs noted that the planned improvements to their data measurement systems are likely to result in a worsening of *reported* reliability levels, due to an increased capability to record when outages occur. This fact was confirmed by PB in their 2002 study for IPART.[133] DNSPs argued that this factor would need to be taken into account when setting S-factor targets. However, it was difficult to make an accurate assessment of the likely impact – were monetary incentives to be introduced this would add an extra form of financial uncertainty.

Other stakeholders supported an S-factor in principle but were concerned about the effectiveness of the proposed mechanism. The EUAA argued that the draft decision on this mechanism would offer "little benefit to consumers". It suggested that the S-factor should incorporate momentary outages and planned outages. EWON argued for a greater emphasis on minimum standards (such as the GCSS, which is discussed further below) on the grounds that these apply to individual customers and provide more effective incentives for improving service in the worst performing areas.

10.3 Tribunal's considerations in making its final decisions

The Tribunal considered all stakeholder responses carefully. Its considerations in making its final decisions are summarised below.

132 A point confirmed by the report commissioned by the Tribunal from PB Associates in 2002, *Review of NSW Distribution Network Service Provider's Measurement and Reporting of Network Reliability*, October 2002.

133 PB Associates, *Review of NSW Distribution Network Service Provider's Measurement and Reporting of Network Reliability,* October 2002.

10.3.1 Collection and publication of service standards performance statistics to continue

The Tribunal has decided to continue to collect and publish service quality performance data and to expand the range of measures included. It believes the ongoing collection and publication of service quality data:

- will provide an incentive for DNSPs to maintain or improve levels of service quality, not least due to the potential poor publicity associated with a decline in performance
- will allow incentives for service quality to apply over a relatively wide range of measures, covering customer services and quality of supply performance, as well as reliability
- may allow inter-jurisdictional as well as inter-NSW comparisons, if common definitions are used.

The Tribunal notes the general stakeholder support for this decision. It also notes that, in the absence of a monetary S-factor, the collection and publication of performance data will be particularly important in helping it to establish whether the DNSPs deliver the levels of service quality during the 2004-09 regulatory period that they have said they will.

10.3.2 Paper trial of an S-factor to be undertaken

The Tribunal has decided to adopt a paper trial of an S-factor during the 2004-09 regulatory period, but not to introduce a monetary S-factor.

After considering stakeholder responses, the Tribunal agrees that basing a monetary S-factor on aggregate-level data alone could, at least in theory, provide an incentive for DNSPs to concentrate on ‘easy wins’ rather than on improving the reliability of the network where it is most needed. To the extent that customer preference information is available, it indicates that it is those customers on the worst performing parts of the network that attach most value to reliability improvements, and that customers *as a whole* may be broadly happy with current service quality levels. The Tribunal does not consider it possible to design a monetary S-factor that *does not* have this potential impact with current data accuracy and availability.

The Tribunal notes that any incentive to concentrate on 'easy wins' would be tempered by the fact that some DNSPs have publicly stated their commitment to improving quality of supply on the worst performing parts of the network. In addition, the Tribunal would be monitoring and publishing service quality performance data at lower levels of aggregation. However, it accepts that these modifying factors could be outweighed in a situation where dollars are at stake.

In its draft report, the Tribunal noted that the reliability performance of DNSPs can vary from year to year. However, it considered that any impact of such variations on the financial risk to the DNSPs would be limited by the fact that the Tribunal’s proposed monetary S-factor would only apply to performance of the network as a whole for three years, and by the 0.5 per cent cap the Tribunal proposed on the amount of revenue exposed.

Despite these measures, the DNSPs still expressed concerns as outlined above. In making its final decision, the Tribunal considered ways in which the impact of year-to-year performance variability could be smoothed. These included the use of deadbands, rolling averages, or making a single aggregate S-factor adjustment at the end of the 2004-09 regulatory period, instead of an annual adjustment. However, the Tribunal found that these smoothing techniques would either lead to a significant reduction in the incentive power of the regime and/or were not currently possible due to limited historic data (eg three to five year rolling averages).

The Tribunal accepts the DNSPs' view that as the accuracy of data improves over the coming years, reported reliability levels are likely to worsen. The Tribunal discussed this issue with the DNSPs and they had the opportunity to build an allowance into forward-looking reliability targets to adjust for this.[134] However, the Tribunal accepts that as the precise impact of data improvement on reliability statistics can only be estimated, there is a remaining element of uncertainty, and that DNSPs are more likely to be concerned about this under a *monetary* S-factor than a paper trial, even if the risk is not asymmetric.

The Tribunal is sympathetic to the views of the EUAA that momentary interruptions deserve further consideration for inclusion in a monetary S-factor in the future. It notes that most DNSPs are unable to measure momentary outages accurately at this stage, but that this capability should have improved by the end of the 2004-09 regulatory period. While the EUAA also put the view that planned interruptions should be included in any S-factor adopted, the Tribunal is concerned that this could result in a perverse incentive for DNSPs to *reduce* planned maintenance.

Having considered all the arguments, the Tribunal has decided that the current data constraints present too much of an obstacle for the introduction of a meaningful monetary S-factor during the 2004-09 regulatory period. It has therefore decided to run a 'paper trial' only.

The Tribunal proposes the following process for the paper trial:

- The Tribunal collects reliability performance data on an annual basis from the DNSPs.[135] Data collected will cover SAIDI, SAIFI, CAIDI and, where/when available, MAIFI,[136] and will be collected by feeder type (using the SCNRRR definitions of CBD, urban, rural short and rural long) as well as for the network as a whole. For purposes of the S-factor, data will be requested to the SCNRRR Normalised Distribution Network (unplanned) definition.[137]
- The Tribunal then analyses these data, comparing them against the levels of performance that the DNSPs have indicated that they expect to be able to achieve over

134 Consistent with the findings of the PB Associates 2002 report.

135 Note that in its Final Recommendations to the Minister on Guaranteed Customer Service Standards and Operating Statistics, the Tribunal has recommended that IPART and the Department of Energy and Utilities (DEUS) liaise so that DNSPs do not have to submit different performance reporting templates to each organisation.

136 SAIDI is the System Average Interruption Duration Index, SAIFI is the System Average interruption Frequency Index, CAIDI is the Customer Average Interruption Duration Index, and MAIFI is the Momentary Average Interruption Duration Index.

137 This definition excludes transmission outages, directed load shedding, and outages which: exceed a threshold SAIDI impact of 3 minutes *and* are caused by exceptional natural or third party events; *and* the DNSP cannot reasonably be expected to mitigate the impact of the event on interruptions by prudent asset management.

the 2004-09 regulatory period. (As noted above, performance data will also continue to be published.)

- Towards the end of the trial, it may be possible for the Tribunal to examine the potential impact of features such as rolling averages. The Tribunal can also use the performance data to continue to model alternative S-factors for the future in consultation with the industry (for example, alternative S-factor formulas, and the impacts of including alternative performance measures).

The Tribunal notes that the running of a meaningful paper trial depends on the cooperation of the DNSPs. It also notes that DNSPs have indicated their willingness to work with the Tribunal in developing and running such a trial.

10.3.3 Subject to Ministerial approval, Guaranteed Customer Service Standards to be expanded

In April 2004, the Tribunal submitted its final recommendations on Guaranteed Customer Service Standards (GCSS), which set out minimum standards for energy utilities in a range of areas, to the Minister for Energy and Utilities. At the time of writing, the Minister had not announced his decision on these recommendations, and the report has yet to be released into the public domain. However, the Tribunal's *draft* recommendations and stakeholder responses to them can by found on its website.[138] Key aspects of these draft recommendations included the introduction of two new GCSS for service reliability:

- duration of interruptions - a requirement for DNSPs to make a payment to customers for every outage that they experience that lasts for over 12 hours
- frequency of interruptions – a requirement for DNSPs to make a payment to customers for each outage they experience in a single year over a certain threshold – the Tribunal sought opinion on adopting the same thresholds as apply in Victoria and as proposed in Tasmania (9 for customers on CBD/urban feeders, and 15 for customers on rural feeders).

The draft report sought stakeholder views on what outages should be excluded when calculating eligibility for payments in relation to the new GCSS. It recommended that, at the least, outages due to transmission events or directed load shedding should not be included and it sought opinion as to whether other events such as major natural or third party events should also be excluded.

In addition, the Tribunal recommended that existing GCSS related to other aspects of service quality be retained. These GCSS include, for example, those covering the provision of telephone services and timely provision of connections. It also recommended that GCSS payments should be made automatically, to strengthen the incentive power of the regime.

[138] IPART, *Review of Guaranteed Customer Service Standards and Operating Statistics – Draft Recommendations*, September 2003, available at www.ipart.nsw.gov.au .

In general, stakeholders supported the continued use GCSS in the form of minimum standards, and EWON supported the use of GCSS as a way to provide incentives for DNSPs to improve service levels in their worst performing areas. However, the DNSPs raised several concerns in relation to the electricity distribution aspects of the Draft Recommendations:[139]

- They argued that a GCSS for timely investigation/resolution of voltage complaints would be unworkable, primarily due to the fact that the time taken to investigate and resolve a voltage problem can vary very substantially, and in some cases it may not be cost-effective to resolve the problem at the present time.
- They were concerned about the introduction of automatic payments, particularly in relation to the new network reliability GCSS. They argued that this would be impractical given that DNSPs are not currently able to measure accurately which customers have been affected by an outage at the distribution substation level or below.
- They put the view that the costs associated with administering a GCSS for appointment keeping with pre-specified time targets/windows would exceed the benefits, given the low numbers of appointments made.
- Country Energy expressed concern that the thresholds proposed for the frequency and duration of interruptions GCSS would result in it having to make a very high number of payments to customers, due to the nature of its network.

The Tribunal considered stakeholder responses carefully in making its final recommendations to the Minister. It also conducted further analysis, including further investigations into the likely costs associated with its draft recommendations.

The decision on whether to publish the GCSS Final Recommendations and whether to approve the recommendations for introduction rests with the Minister. However, the Tribunal affirms its view that GCSS are a useful way to provide incentives for utilities to improve service levels in their worst performing areas for small customers,[140] while at the same time providing an acknowledgement to customers when they experience particularly poor service levels. The Tribunal therefore affirms its view that GCSS should form part of a package of measures to provide incentives for service quality for DNSPs.

139 A more in-depth discussion of responses to the Draft Recommendations is provided in the Final Recommendations document itself. The Tribunal has recommended to the Minister that the Final Recommendations report be published in due course.

140 Note that GCSS only apply to customers consuming less than 160MWh per year.

11 COST PASS THROUGH MECHANISM

The building block costs used in calculating the X-factors in the weighted average price cap are derived from estimates of each DNSP's future operating and capital expenditure. These estimates are submitted to the Tribunal by the DNSPs, then subject to independent review. However, some events that could occur during the 2004-09 regulatory period and could affect the DNSPs' costs have not been allowed for within these estimates—due to uncertainty about whether and when the events will occur, and if they do, what the cost implications will be.

Because the X-factors are fixed for the length of the regulatory period, the DNSPs bear the financial risk associated with these events if they occur. As part of its review, the Tribunal considered whether in some circumstances, it might be appropriate for this risk to be shared with customers via a mechanism that allows the DNSPs to pass through certain additional costs in network prices.

This chapter sets out the Tribunal final decisions in relation to this cost pass through mechanism, summarises its draft decision and stakeholder responses, and discusses its considerations in making its final decisions.

11.1 Final decisions

The Tribunal has decided to introduce a specific cost pass through mechanism for costs incurred for the following specified events:

- **potential changes in occupational health and safety requirements governing live-line working procedures**
- **potential amendments to the Electrical Supply Act seeking to clarify the definition of 'electrical installation and point of supply'**
- **possible introduction of additional expected payments linked to Guaranteed Customer Service Standards (GCSS) as a result of IPART's recommendations to the Minister for Energy and Utilities to introduce payments linked to network reliability**
- **possible changes in the Government's policy on interval/time based metering, which may entail a more widespread roll-out of interval or other meters to customers.**

The Tribunal has also decided to introduce a general cost pass through mechanism, allowing for the pass through of approved costs or cost savings in the following circumstances:

- **changes in certain taxation obligations**
- **changes in certain regulatory obligations.**

The incremental costs to be passed through via both these mechanisms (or cost savings in the case of the general pass through mechanism) will need to be approved by the Tribunal.

The amounts passed through will be outside the weighted average price cap and price limits for individual tariffs.

11.2 Summary draft decision and stakeholder responses

The Tribunal's draft decision was that it would not introduce a mechanism to allow the DNSPs to pass through unforseen costs that arise during the regulatory period. This decision was based on its view that it would be difficult to design a cost pass through mechanism that could meet all of the following criteria:

- provides a clear definition of eligible costs (for example, how do you define a rare event?)
- keeps administrative costs to a manageable level (for example, the costs of assessing applications to pass through costs)
- balances the interests of customers and DNSPs in terms of incentives for efficiency (for example, the Tribunal was concerned that a pass through mechanism would reduce the incentives for DNSPs to minimise costs)
- allows the change in costs to be readily distinguished from costs already allowed for (how would the Tribunal determine whether the claimed costs have already been factored into the cost projections submitted by the DNSP as part of this review, given that it assesses these projections at a high level only?).

The DNSPs and the Energy Network Association (which represents the DNSPs and other energy businesses) expressed strong opposition to the draft decision. In general, these stakeholders argued that it could be possible to design a pass through mechanism that satisfies the above criteria.

The DNSPs also identified a number of cost items for which there is uncertainty about whether they will need to incur them, and if they do, how much they will need to spend. These 'foreseeable but uncertain' cost items relate to the possible changes to the Electricity Supply Act and occupational health and safety requirements, GCSS and interval metering requirements described in section 11.1 above. The need to incur these costs is largely contingent on regulatory or policy decisions by Government, and so is outside the control of the DNSPs and the Tribunal. The Tribunal's draft determination did not provide for these foreseen but uncertain costs to be recovered, and the DNSPs argued that the final determination should either include them in the cost building blocks or allow them to be passed through via a cost pass through mechanism.

Integral Energy also noted that costs associated with changes to business-to-business transfer requirements had not been provided for in the draft determination. It argued that these costs should also be included in the cost building blocks.

11.3 Tribunal's considerations in making final decisions

In making its final decisions, the Tribunal considered all stakeholder comments, and the findings of its consultants and its own analysis. Its considerations in relation to each of these decisions are discussed below.

11.3.1 Foreseen but uncertain costs will be passed through via a specific cost pass through mechanism

The Tribunal decided that it will allow DNSPs to pass through any approved costs arising from four specific events as defined in the determination. These events relate to:

- changes to OH&S requirements governing live line working procedures
- amendments to the Electrical Supply Act that seek to clarify the definition of 'electrical installation and point of supply'
- changes to requirements to make customer payments for breaches of the GCSS
- changes in the Government's policy on interval/time-based metering.

As Chapter 4 discussed, the possibility that these events will occur is foreseen, and, to varying degrees, the DNSPs have submitted estimates of the costs they are likely to incur if they do occur. However, the Tribunal's consultant, Wilson Cook, was unable to assess the reasonableness of these estimates due to the uncertainty about whether the events will occur, and if they do, exactly what the resulting changes and cost implications will be.

The Tribunal considers that this uncertainty makes it inappropriate for it to include an allowance for these costs in the cost building blocks and that these costs should be recovered as a pass-through item. Given that the costs were foreseen at the time of the determination, it also considers it inappropriate for these costs to be subject to a materiality threshold (as would be the case if they were to be passed through via the general cost pass through mechanism discussed below). It therefore decided to establish a specific cost pass through mechanism to allow additional costs associated with the specified events to be passed through, subject to the approval process described in section 11.3.3 below.

The Tribunal decided not to allow the pass through of costs associated with changes to business-to-business transfer requirements, as proposed by Integral Energy, under the specific cost pass through mechanism. Wilson Cook was unable to form a judgement of the reasonableness of Integral Energy's estimate of the costs likely to be associated with this event. In addition, the Tribunal considered that it was unable to clearly define this event to limit the scope of pass through amounts to the event described by Integral Energy. However, if a material change to MSATS[141] occurs that affects their business-to-business costs, the DNSPs would be able to apply for the pass through of these costs under the general cost pass through arrangements discussed below.

11.3.2 Unforeseen costs and cost savings associated with tax and regulatory changes will be passed through via a general cost pass through mechanism

The Tribunal decided to establish a general cost pass through mechanism for costs associated with changes in tax and regulatory obligations. In making this decision, it considered the DNSPs' analysis of how such a mechanism could satisfy the criteria it outlined in its draft report and conducted further analysis of its own.

141 MSATS is NEMMCO's Market Settlement and Transfer Solution, and is used by participants to manage metering data, NMI standing data, customer transfers, and participant relationships.

The general cost pass through mechanism it has established is more limited than the one applied by the ACCC in recent transmission decisions, but is broader than the one applied by the ESC in Victoria in its electricity distribution and gas decisions. The Tribunal notes that the Electricity Pricing Order administered by ESCOSA[142] allows for the pass through of changes in taxes and compulsory changes in the standards of services.

The principal benefit of a general cost pass-through mechanism is that it will reduce the financial risk for DNSPs associated with unforeseen changes in their taxation and regulatory obligations, by allowing them to pass through any incremental costs they incur as a result of these changes to customers. However, there also are several trade-offs, the main one being that with a general cost pass through mechanism, the DNSPs have less incentive to manage these additional costs to minimise the impact on customers. Another trade-off is the increased administration costs associated with assessing applications to pass through costs under such a mechanism.

The Tribunal considered these trade-offs when making its decisions. It has attempted to partially mitigate any adverse efficiency impacts by limiting the scope of the costs that can be passed through to those that the DNSPs have little ability to influence.[143] This limitation also reflects its desire to ensure that the regulatory framework does not become a cost-plus based regime. Such an outcome would not only provide poor incentives for DNSP efficiency, it would also be inconsistent with the Tribunal's obligation under the Code to maintain an incentive-based regulatory framework.

The Tribunal has also attempted to mitigate the cost and adverse efficiency impacts of the general pass through mechanism by establishing a materiality threshold.

The Tribunal also is of the view that the cost pass through mechanism should be symmetrically applied, with events that both increase *and decrease* costs for DNSPs being eligible for pass through. That is, if a tax or regulatory event occurs that materially lowers a DNSPs costs, then the Tribunal may approve the pass through of cost savings to customers.

Limiting the scope of pass through events to taxation and regulatory events

The Tribunal has defined taxation and regulatory events in a way that is broadly in line with the definitions use by other regulators in cost pass through mechanisms. The definitions of these events are set out in Annexure 1 of the determination.

By limiting the scope of pass through events to these two events, the Tribunal has deliberately excluded insurance and terrorism events. In making this decision, it took into account that the administration costs associated with including such events would be high. For example, it notes that the ACCC requires the submission of insurance invoices each year under some of its cost pass through mechanisms for transmission businesses. In relation to the terrorism, there is a lot of uncertainty about what costs should appropriately be passed through if such an event occurred and this uncertainty would increase costs of the pass-through approval process.

142 Esssential Services Commission of South Australia.

143 That is, to influence both whether the event occurs, and if does, the level of costs that they incur as a result.

For example, if the DNSP's assets were insured against loss or damage due to terrorist acts, there would be no need for the costs associated with replacement or repair to be passed through to customers. However, if its assets were not insured, would it be appropriate for customers to bear the replacement costs, or should these costs be borne by the DNSP's owner? The answer to this is likely to depend on the context, such as the reasons why the assets were not insured. There is also a question of whether the costs associated with any subsequent liabilities arising from loss of service should be passed through. The Tribunal considers that these questions are more appropriately addressed during a regulatory review than during an assessment of a cost pass through application.

There would also be a risk of moral hazard if insurance and terrorism events were included in the scope of the general cost pass through mechanism. For example, including insurance events could limit the incentives for DNSPs' to take action to minimise premiums — for example, shopping around, or negotiating with insurers over appropriate premiums, or taking actions that could mitigate risks and reduce insurance costs. Including terrorism events would effectively insure the DNSP against the loss of assets due to terrorism acts. This would mean that their customers bear the risk of this loss, which may encourage the DNSPs to under-insure assets — effectively transferring the risk from their insurer to customers. Customers are unlikely to be better placed to manage such losses than insurers who can spread the risk as a normal part of their business.

Establishing a materiality threshold

The Tribunal has established a materiality threshold per event to limit the pass through of costs to those that have a significant impact on the DNSP's financial position. The Tribunal considers that small cost changes should be viewed to be part of the ordinary operation of business.

The DNSPs generally supported the imposition of a materiality threshold. For example, Integral Energy argued that a threshold for each event of plus or minus $5 million in aggregate over the regulatory period was appropriate.[144] Country Energy proposed a threshold equivalent to 0.5 per cent of annual revenue requirements, which it estimated was equivalent to around $2.5 million for its business[145].

The Tribunal believes that the appropriate size of the threshold represents a trade-off between:

- not creating a cost-plus form of regulation, and
- not setting the threshold too high, so that events that have a serious impact on the DNSPs financial position do not qualify for pass through.

The Tribunal has decided to define a materiality threshold equivalent to 1 per cent of average annual smoothed revenue requirements over the regulatory period per event. That is, the Tribunal will only pass through events for which the average annual impact on cost as a result of the event is equivalent to 1 per cent of the average annual smoothed revenue requirements (as laid out in the Tribunal's determination). The threshold is not cumulative across events. The Tribunal considers that a materiality threshold at this level would limit pass through to events that have a significant impact on a DNSP's costs and avoids the risk of the regulatory framework becoming a cost-plus regime. The Tribunal's financial

144 EnergyAustralia submission, 5 March 2004, p 53.
145 Country Energy submission, 5 March 2004, p 113.

modelling indicates that cost increases under this threshold would be unlikely to have a very serious impact on the financial position of the DNSP if it had to wait until the next review for higher costs to be reflected in the business's X-factors/revenue requirements.

Applying a symmetrical approach

Under the Tribunal's general cost pass through mechanism, DNSPs are obliged to inform the Tribunal of a material cost-reducing tax or regulatory change event within 90 working days of that event occurring. The Tribunal may also initiate the process of approving the pass-through of cost savings following such an event.

11.3.3 DNSPs will need to apply for approval to pass through incremental costs

DNSPs seeking to pass through costs associated with either a specific or general cost pass through event will need to apply to the Tribunal for approval of these costs. The costs passed through under these mechanisms must be incremental—that is, they must not have been already allowed for in the cost blocks used to calculate the X-factors in the weighted average price cap. In addition, they must have been incurred as a direct consequence of the pass through event.

The Tribunal requires DNSPs to apply for cost pass through within 90 working days of the pass through event occurring. Note that in the case of the general pass-through mechanism such an event can be either a positive change event (one that results in increased costs) or a negative change event (one that results in cost savings). The DNSP will need to detail:

- the nature of the pass through event
- the date the event occurred
- the additional costs already incurred and likely to be incurred over the remaining years of the regulatory period or, in the case of a negative change event, the expected cost savings
- the amount to be passed through and the proposed timing of this pass through.

DNSPs will also be required to provide evidence of the actual and likely costs, and to demonstrate that the costs are efficient and occur solely as a consequence of the pass through event.

The Tribunal will approve a total amount that can be passed through, as well as a profile of recovery over the remainder of the regulatory period. In approving the total amount that can be passed through, the Tribunal will take into account:

- the efficiency of the DNSP's decisions and actions, including whether (in the case of a positive change event) the DNSP has failed to take any action that could have reduced the costs incurred
- the time cost of money (based on the weighted average cost of capital)
- the need to ensure that the DNSP only recovers costs for which no provision has been made for in this determination
- the need to ensure that the DNSP only recovers any actual or likely increment in costs incurred as a consequence of the pass through event

- in the case of a positive regulatory change event, whether the increment in costs that the DNSP has incurred since the start of the regulatory period and is likely to incur until the end of the regulatory period as a result of this event, is reasonable
- in the case of a positive regulatory change event, any reasonable costs that the DNSP has incurred prior to, but in preparation for, the occurrence of that event (within the 2004-09 regulatory period)
- in the case of a tax change event, any change in the way another tax is calculated, or the removal or imposition of another tax, which offsets the impact of the tax change event
- any other factors the Tribunal considers relevant.

In setting the profile of recovery, the Tribunal will have regard to the expected impact on customers from the higher price arising from the pass through of costs.

Prior to making a decision on the cost pass through, the Tribunal will consult with the relevant DNSP and such other stakeholders as it considers appropriate.

11.3.4 The pass through amounts will be outside the weighted average price cap and price limits

The Tribunal will allow the DNSP to recover all approved cost pass through amounts for the year (either specific or general) as a single additional charge on top of the total network tariff — that is, DNSPs will be able to increase their network tariffs over and above that allowed under the weighted average price cap and the individual price limits to recover the approved cost pass through amounts.

DNSPs will be required to submit the proposed increase in network tariffs for each tariff class to the Tribunal as part of the annual price approval process, to demonstrate that they expect to recover the pass through amounts approved by the Tribunal in that year. They will need to calculate the additional charges in a manner consistent with the pricing principles described in Chapter 15 and based on the same expected volumes used to set the transmission cost recovery tariffs.

Under these cost pass through arrangements, the DNSP will bear the forecast risk—there will be no 'squaring up' of actual revenue collected from these charges against that allowed by the Tribunal. This is consistent with the workings of the weighted average price cap, where the DNSP bears the volume risk.

The cost pass through amount will be outside the weighted average price cap and price limits on network tariffs. Price shocks to customers will be managed via the profiling of recovery over the regulatory period.

12 OTHER ISSUES CONSIDERED IN RELATION TO THE WEIGHTED AVERAGE PRICE CAP

In making its final decision on the weighted average price cap formula for regulating DUOS tariffs, the Tribunal considered a range of additional issues that could affect the application of this form of regulation. These issues include:

- whether to include a correction factor to allow for factors arising in the 1999 regulatory period to be carried forward into the 2004 regulatory period
- whether to introduce a risk hedging/benefit sharing mechanism to account for significant differences in the actual and projected growth forecasts underlying the calculation of the X-factors
- how to treat revenue DNSPs earn from renting and access to, power poles and cable ducts
- whether to reopen its 2002 determination on capital contributions.

The Tribunal's review and public consultation process identified no issues in the 1999 regulatory period that need to be carried forward into the 2004 regulatory period via a correction factor. Therefore, a correction factor is not required. The Tribunal's final decision on each of the other issues, and its analysis and rationale for these decisions, is discussed below.

12.1 Final decision

The Tribunal's final decision is that:

- **it will not introduce a risk hedging factor in the weighted average price cap control formula**
- **it will make no adjustment to the DNSPs' notional revenue requirements for revenue earned from pole and duct rentals**
- **it will not re-open its April 2002 determination on capital contributions.**

12.2 Tribunal's considerations in making final decisions

12.2.1 No risk hedging factor to be introduced

Under a weighted average price cap form of regulation, the X-factors have been set to recover each DNSP's smoothed revenue requirements based on a forecast level of sales. However, its actual revenues earned will fluctuate according to its actual level of sales. This creates a 'forecast risk' for DNSPs to manage during the regulatory period.

In its notice on the form of regulation[146], the Tribunal raised the option of including a 'hedging factor' in the weighted average price cap formula to address this forecast risk. In its issues paper[147], it described the possible inclusion of an 'H-factor' in the price control equation:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t+1} * q_{ij}^{t-1}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t} * q_{ij}^{t-1}} \leq (1 + \Delta CPI + X_{t+1} + S_{t+1})(1 + H)$$

The intent, as signalled in the notice on the form of regulation, was to offer a sharing of risk between customers and DNSPs when actual sales volumes are *significantly* higher or lower than forecast. That is, the mechanism would apply above a threshold level of divergence from forecast growth (for example, if actual growth were outside a specified number of percentage points of forecast growth).

During the Tribunal's consultation process, the DNSPs expressed varying views on introducing a risk hedging factor. EnergyAustralia was opposed to such a factor, while Integral Energy argued strongly for its introduction. In its response to the Secretariat's preliminary analysis discussion paper,[148] Integral Energy proposed a risk hedging factor along the lines of the option included in Tribunal's issues paper. While initially opposing the introduction of a risk hedging factor, Country Energy indicated that it would be interested in pursuing a mechanism as proposed by Integral Energy to deal with asymmetric risk[149] or a revenue 'floor' to mitigate any potential under-recovery of economic costs due to forecasting errors. [150]

In response to the Tribunal's draft decision not to introduce a risk hedging factor, EnergyAustralia and Country Energy both argued that it would be appropriate for the Tribunal to introduce a risk hedging mechanism if it adopted MMA's growth forecasts rather than the DNSPs own forecasts.[151] For example, EnergyAustralia submitted:

> Whilst EnergyAustralia is willing to bear the risks of variances from its own forecasts, it is unwilling to bear the asymmetric risks imposed upon it by using forecasts which EnergyAustralia feels has fundamental flaws in its development.[152]

Integral Energy also re-affirmed its support for a risk hedging factor in response to the Tribunal's draft decision.

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146 IPART, *Notice under clause 6.10.3 of the National Electricity Code – Economic Regulatory Arrangements,* NCR-10, June 2002.

147 IPART, *Regulatory Arrangements for the NSW Distribution Network Service Providers from 1 July 2004, Issues Paper*, Issues Paper DP-58, November 2002.

148 Integral Energy, *2004 Electricity Network Review Preliminary Analysis Response,* 20 October 2003, pp 16-18.

149 Country Energy submission, 20 October 2003, pp 12-13.

150 Country Energy submission, 5 March 2004, p 118.

151 Although for Country Energy, the revised MMA forecasts (submitted after Country Energy's submission) coincide with those of Country Energy.

152 EnergyAustralia submission, 5 March 2004, p 14.

The introduction of a risk hedging factor is primarily about managing the financial risks associated with uncertain volume forecasts:

- the risk for the DNSP if volumes turn out significantly below forecast, resulting in revenues below expected levels
- the risk for customers if volumes turn out significantly above forecast, resulting in higher than expected revenues.

Country Energy's proposed revenue 'floor' only addresses the first of these risks.

It is not clear to the Tribunal that a risk hedging factor based upon revenues is necessarily the appropriate means of dealing with these risks. Indeed, in their joint submission on the form of regulation, the DNSPs argued that the weighted average price cap was superior in terms of the ability of businesses to manage volume risk than other approaches that placed constraints on the revenues that the DNSP could earn.[153] This is likely to be one of the factors underlying EnergyAustralia's original opposition to the risk hedging factor, on the grounds that it would constrain the revenue earned by DNSPs.

In particular, the Tribunal considers that the focus on risk to revenue is inappropriate, as it is the risk to profit that matters to the DNSP's owner. It notes that a DNSP's profit risk can be mitigated by managing costs and aligning tariff structures to underlying costs. For example, in the case of lower-than-expected demand, while revenues would be lower than expected, it would be expected that capital and operating expenditures would similarly be lower than expected. If tariff structures are aligned to underlying costs, then the impact on profit will be mitigated by the reduction in costs. Similarly, a higher-than-expected growth rate would need to be supported by higher capital and operating costs. The impact on profits would unlikely be as great as indicated by the increase in revenues alone.

A problem with a risk hedging factor is that it could, for example, in the case of higher than expected growth, reduce the DNSP's revenues with no regard to the underlying cost of meeting this demand. The 'sharing' of risk between the DNSP and its customers could reflect the costs to the DNSP, but the problem would be trying to determine the shares. Similarly, if growth were lower than expected, then the risk hedging mechanism or a revenue 'floor' would both provide more revenue than under a straight weighted average price cap to the DNSP. The DNSP would also benefit from having lower costs as a result of lower demand but the impact on its profits would be uncertain.

Further, in their submissions on the form of regulation, the DNSPs argued that the weighted average price cap provides incentives for DNSPs to price efficiently, moving tariffs more in line with marginal costs.[154] This would mean costs are more closely aligned with tariffs, reducing the risks to DNSPs from volume fluctuations.

The Tribunal recognises that the DNSPs will face more volume risk under a weighted average price cap than under a revenue cap. This risk can, in part, be managed by better alignment between tariff structures and cost structures.

153 NSW Distribution Businesses' submission to IPART's Discussion Paper, DP48, September 2001, p 9.

154 *Ibid*, Attachment 1, p 19.

The Tribunal does not accept the DNSPs' contention that its adoption of the MMA forecasts creates greater volume risk for these businesses than if the DNSPs' own forecasts were applied. The Tribunal has adopted what it considers to be the 'most likely' growth scenarios for the businesses, having had regard to their own forecasts and those produced by MMA. The Tribunal is not of the view that the MMA forecasts introduce an asymmetric risk for DNSPs and therefore does not accept the arguments advanced by EnergyAustralia (and Country Energy) that there is a need to introduce a risk hedging factor. Indeed, for Country Energy and Australian Inland, the MMA forecasts coincide with the DNSPs' own forecasts.

For these reasons, the Tribunal has decided not to introduce a risk hedging factor for the 2004-09 regulatory period.

12.2.2 DNSPs will be allowed to retain revenue from pole and duct rentals

Some DNSPs receive payments in return for allowing third parties (often telecommunication companies) to use their power poles and cable ducts for non electricity-related purposes (known as pole and duct rentals). In principle, the revenue a DNSP earns from these payments could affect its notional revenue requirements, and thus the X-factors in its weighted average price cap.

The Tribunal considered whether it should adjust notional revenue requirements to account for this revenue.

It has decided that pole and duct rental activities are non-distribution services (see Chapter 16). As such, they are not subject to regulation by the Tribunal. However, regulated assets are used to provide these services, although the Tribunal understands that DNSPs do not currently allocate any regulated asset costs to them.

The Tribunal believes there is an in-principle case for applying a portion of the incremental profits earned by DNSPs from pole and duct rental activities, as an offset to their notional revenue requirements. This offset would share the benefits a DNSP derives from using regulated assets to service non-regulated customers with its regulated business customers. Another way of looking at this offset is that it would effectively allocate a portion of the cost of the regulated asset base to the cost of providing non-distribution services such as pole rentals.

The Tribunal notes that regulators in South Australia and the United Kingdom have recently considered this issue. The South Australian regulator has yet to release its decision. In the United Kingdom, OFGEM provides for a sharing of revenues derived from telecommunications companies by deducting a proportion of net revenues earned from regulated revenue requirements.[155]

In confidential submissions to the Tribunal, the DNSPs indicated that revenue earned from pole and duct rentals is modest relative to their regulated business revenues. In balancing the potential benefits to regulated customers against the likely administrative costs for DNSPs and the Tribunal, the Tribunal has decided that it will make no adjustment to the notional revenue requirements for revenue earned from pole and duct rentals in the 2004-09 regulatory period. This is consistent with the Tribunal's draft decision on this matter.

155 OFGEM, Open letter on energy networks providing telecommunications services, 30 October 2001.

The Tribunal's decision means that DNSPs will retain the full benefit of profits earned from pole and duct rentals as part of their non-regulated business activities. The Tribunal's decision also means that all incremental costs associated with pole and duct rental services have been excluded from the building block costs underlying the notional revenue requirements and the calculation of the X-factor.

The Tribunal notes Origin Energy's strong opposition to the Tribunal's decision on this matter and its concerns about cost allocation.[156] The Tribunal considers this issue should be revisited at the next distribution determination, if the value of the DNSPs' revenues from pole and duct rentals becomes material relative to the total revenues of their regulated businesses.

12.2.3 The Tribunal will not re-open its capital contributions determination

The Tribunal's capital contributions policy has implications for the type of charges that DNSPs can levy under the weighted average price cap. In particular, EnergyAustralia has proposed introducing an infrastructure charge, which the Tribunal considers to be a form of capital contribution. The proposed infrastructure charge is to apply to new and upgraded three-phase or large installations. In its submission, EnergyAustralia noted that the charges are intended to "reflect a user-pays principle for the cost of providing capacity demanded with very poor load utilisation".[157]

The Tribunal's April 2002 review of capital contributions[158] determined that, as a general rule:

- customers will pay the costs of providing and installing the lines and equipment up to a defined point of connection point to the network
- the defined point ('the linkage point') is the point on the network at which the use of assets changes from shared among customers generally to dedicated to one or more customers
- the DNSP will be required to pay for all other costs — that is, those incurred beyond the linkage point.

There are two exceptions to this general rule where customers can be required to contribute to costs after the first linkage point:

- rural customers defined as customers in those parts of the network where the 'after diversity maximum demand' per kilometre of line is less than 300kVA or where the local council has zoned the area as rural
- large customers defined as customers that would require more than 50 per cent of the capacity of the existing network be augmented.

156 Origin Energy submission to the draft report, March 2004, p 5.

157 EnergyAustralia's submission to 2004 review, 10 April 2003, p 77. Other than indicating that the infrastructure charge has been calculated to capture a significant proportion of funding necessary to augment the network capacity, the submission does not detail how the infrastructure charges will be derived. However, EnergyAustralia has indicated verbally to the Tribunal's Secretariat that the infrastructure charges would be based on costs associated with shared network assets.

158 IPART, *Capital Contributions and Repayments for Connections to Electricity Distribution Networks in New South Wales - Final Report*, Determination No.1 2002, April 2002.

EnergyAustralia's proposed infrastructure charge does not fall within the definitions of the exceptions to the general rule and, since it involves recoupment of shared network costs, it is inconsistent with the Tribunal's determination on capital contributions.

The capital contributions determination has been in operation for little more than 18 months and the Tribunal is not aware of any issues arising from its implementation. Given this, the main issue it considered for the 2004 distribution pricing determination was whether there is sufficient merit in EnergyAustralia's proposal to introduce an infrastructure charge to justify it re-opening the capital contributions determination.

Because the proposed infrastructure charge is designed to recover a proportion of shared network costs, the key issue is whether the capital contributions determination should be re-opened to allow for capital contributions to recover more than just direct customer connection costs.

In response to the Tribunal's draft decision on this matter, EnergyAustralia submitted:

> … large customers have a disproportionate impact on the network, in particular new and upgraded three phase or large installations which in domestic situations are almost always associated with large air conditioning installations. It is clearly appropriate for such customers to make an additional contribution towards the upstream infrastructure development they cause at the time of installation. IPART is therefore requested to reconsider this decision.[159]

In making its 2002 decision on capital contributions, the Tribunal considered whether the capital contributions should recover shared network costs and decided against this for the following reasons:

- its believes that usage charges, not capital contributions should be the primary form of price signal
- connection costs vary widely, depending on the network conditions in the area the customer is located
- its consultant (Meritec) advised it that it is conceptually difficult to link augmentation costs with specific connections and that no robust basis for estimating connection-driven augmentation costs by customer category could be determined
- augmentation costs are driven by growth of existing customers' loads as well as by new connections.

On this last point the Tribunal noted in its capital contributions determination:

> … the efficiency arguments for signalling costs to new users are weak for existing assets. For the most efficient utilisation of the capacity, the principle is that if capacity is scarce the costs of rationing or expanding that capacity should be signalled to all users not just some.[160]

159 EnergyAustralia submission, 5 May 2004, p 66.

160 IPART, *Capital Contributions and Repayments for Connections to Electricity Distribution Networks in New South Wales - Final Report*, April 2002, p 4.

The Tribunal considers that its conclusions on the difficulties associated with identifying augmentation costs and the inequities and inefficiencies of charges only for new customers remain valid. However, it recognises that EnergyAustralia's proposal to introduce an infrastructure charge has been made at a time when growing demand requires significant capital investment to ensure that there is sufficient capacity to meet demands on the system during system peak periods. At the time its original capital contributions determination was made, these capacity constraints were not identified as a critical issue affecting pricing.

The Tribunal has argued that, in its view, usage charges rather than capital contributions should be the primary form of price signal. However, metering constraints for some customer groups mean that the current charge structure does not adequately signal the cost of peak period consumption. This is the case for residential and small business customers in particular. It may be the case that an infrastructure charge could complement the existing charge structure by targeting customer with peakier loads.

However, EnergyAustralia has also proposed that, as part of its suite of tariff reforms, time of use meters would be installed for those customers that install fixed wired (or three-phase) air conditioners. Presumably, these customers would also be liable for an infrastructure charge under EnergyAustralia's proposal. The installation of time of use metering would allow more accurate price signalling for this group of customers and would appear to weaken the arguments for an infrastructure charge for residential and small business customers.

For larger customers with interval metering, the Tribunal does not accept the argument that an infrastructure charge offers better signals to customers than usage prices. With interval meters these customers can face charges that are based on both the time of consumption and the capacity/demand they impose on the system. The indicative charge structure proposed by EnergyAustralia includes substantial charges for connections at high voltage or low voltage substation level. It seems likely that these charges are designed to recover up-front capital costs that could be recovered by targeted usage charges on customers with interval metering.

The Tribunal reaffirms the view it put forward in its draft report that there is not a strong enough case for introducing an infrastructure charge to justify re-opening its capital contribution determination. It considers that the same signals relating to the costs of capacity could be more appropriately sent through usage charges rather than through an up-front charge. The Tribunal has not seen any evidence that customers are more responsive to up-front charges than on-going usage charges.

13 TRANSMISSION RECOVERY ARRANGEMENTS

DNSPs incur transmission-related costs on the electricity that they distribute. The DNSPs will set transmission cost recovery tariffs[161] to recover these costs. Transmission charges paid by the DNSP to transmission network service providers (TNSPs) form the largest component of these costs. The other costs to be recovered under these arrangements include avoided TUOS payments made to embedded generators, and inter-distributor transfer payments to other DNSPs. These will be collectively known as 'transmission-related payments'.

The DNSPs forecast these costs in order to set the transmission cost recovery tariffs for the following year. At the end of the year, the DNSP will realise actual revenue from the tariffs, and actual costs incurred. The Tribunal has decided that a Transmission Overs and Unders Account will apply in the 2004-09 regulatory period to accommodate any variation in these amounts. The DNSP will be able to recover any balance in the account, by adjusting transmission cost recovery tariffs on a prospective basis, by a Transmission Recovery Amount, subject to the network price limits.

Price limits on the total network tariff must be taken into consideration by the DNSP when setting the transmission cost recovery tariffs. If this restricts the full recovery of the balance of the account in any one year, or if the DNSP opts for a phased approach to recovering transmission costs to maintain price stability, any unrecovered amount will accrue in the overs and unders account and can be considered when setting the tariffs in the following year. Any outstanding balance will be subject to an interest component (equal to the nominal rate of return).

This chapter sets out the Tribunal's decisions on the recovery of transmission-related payments. It also provides an overview of the draft decisions and stakeholder responses to these decisions, and discusses the Tribunal's considerations in making its final decisions.

13.1 Final decisions

The Tribunal has decided that transmission cost recovery tariffs will be regulated through the following arrangements:

- **The DNSP will set transmission cost recovery tariffs each year to recover the following forecast costs (collectively referred to as 'transmission-related payments') for that year:**
  - **transmission charges to be paid to TNSPs for use of the transmission system (use of system and connection charges, net of settlement residue payments)**
  - **avoided TUOS to be paid to embedded generators as calculated and paid in accordance with the National Electricity Code**
  - **payments to be made to other DNSPs for use of their network (inter-distributor transfer payments).**
- **The DNSP will record the difference between the actual transmission-related payments it pays and the actual revenue it receives through transmission cost recovery tariffs, in a transmission overs and unders account.**

161 Also known in the industry as 'TUOS' tariffs, which are part of the total network tariff.

- **The DNSP will recover or return any balance in the overs and unders account by adjusting transmission cost recovery tariffs in the following year. The Tribunal will review the amount the DNSP has chosen to recover annually.**

The Tribunal may consider increasing the price limits on network tariffs, should the forecast balance of a DNSP's transmission overs and unders account accumulate to more than fifteen per cent of the value of actual transmission-related payments incurred in the previous year. This is set out in the Tribunal's Rule – Departure from Price Limits, January 2004.

The Tribunal will publish a guideline, separate to the determination, that sets out a methodology for calculating avoided TUOS payments.

13.2 Summary of draft decisions and stakeholder responses

The Tribunal's final decision has affirmed the key elements of the transmission recovery arrangements that were set out in the draft report. In submissions in response to the draft report, some of the DNSPs expressed concern that these arrangements would not allow the reasonable recovery of transmission charges, particularly in light of the relatively large transmission price increases proposed by the TNSPs for 2004/05 to 2008/09. These concerns mainly arise from the Tribunal's decision to place price limits on total network tariffs, which could constrain the increase in transmission cost recovery tariffs and limit the recovery of transmission-related payments in any one year.

EnergyAustralia and Country Energy argued that it would be better to allow the direct pass-through of actual transmission charges, outside of the network price limits.[162] For example, Country Energy suggested that the Tribunal use a 'truing up factor' to account for the difference between forecast and actual transmission charges, and that this factor be passed through outside the price limits and with no time lag.

Integral Energy, on the other hand, supported the Tribunal's approach. It put the view that there is sufficient flexibility within the price limits to set transmission cost recovery tariffs, and that it considers it unlikely that the accumulated balance of its transmission overs and unders account will reach substantial levels by the end of the regulatory period.[163] However, it requested that the Tribunal establish a carry-over mechanism to ensure that any balance in the transmission overs and unders account at the close of the regulatory period could be recovered in the next regulatory period.

13.3 The Tribunal's considerations in making its final decisions

In making its final decisions on the transmission recovery arrangements, the Tribunal considered all stakeholder perspectives, the requirements of the Code, and its own analysis. It also took into account that the ACCC's draft decision on transmission network pricing proposes transmission price increases for 2004/05 - 2008/09 that are considerably less than the TNSPs' original proposals.[164] Although the ACCC's final decision is not expected until April 2005, the Tribunal is confident that its own decisions on transmission arrangements will allow reasonable recovery of transmission charges incurred by the DNSPs over the

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162 Country Energy submission to Draft Determination, 5 March 2004, p 127; EnergyAustralia submission to Draft Determination, 5 March 2004.

163 Integral Energy submission to Draft Determination, 5 March 2004, p 82.

164 ACCC, *Draft Decisions for TransGrid and EnergyAustralia transmission revenue caps*, 4 May 2004

regulatory period. Each of the main elements of these arrangements is discussed in detail below.

13.3.1 DNSPs to separate network tariffs into DUOS tariffs and transmission cost recovery tariffs

From 1 July 2004, the DNSPs will be required to separate their network tariffs into DUOS tariffs and transmission cost recovery tariffs. The DUOS tariffs will be regulated through the weighted average price cap for each year (see Chapter 3). The setting of transmission cost recovery tariffs by DNSPs will be supported by the transmission recovery arrangements described in this chapter.[165]

The DNSPs separated their 2003/04 network tariffs into DUOS tariffs and transmission cost recovery tariffs, using the Joint Allocation Methodology they proposed in 2002. This methodology aims to preserve the pricing signals inherent in the transmission charges set by the ACCC where this is practical.[166]

13.3.2 DNSPs to set transmission cost recovery tariffs to recover forecast transmission-related payments

Under a weighted average price cap form of regulation, the extent to which a DNSP recovers its costs depends on the actual volumes of electricity it sells compared to the forecasts of these volumes used in setting the X-factor in the price cap formula. The Tribunal has decided to allow for the recovery of transmission-related costs through separate arrangements, with the objective of allowing each DNSP to recover its actual transmission-related payments over the regulatory period. Such an approach is provided for in the Code, and the Tribunal believes it is appropriate because transmission-related costs are not set or controlled by the DNSPs.

The Tribunal decided that the DNSPs will set transmission cost recovery tariffs based on a forecast of their transmission-related payments for the year the tariffs are being charged. The Tribunal considered the DNSPs' suggestion that the tariffs be based on *actual* transmission costs incurred. However, it believes that practically, this could only occur if the transmission cost recovery tariffs were based on historical costs. This would create a mismatch between revenues and costs, due to the two-year time lag between when the costs are actually incurred and when the tariffs are set and applied. The Tribunal considered that this would distort the transmission price signals to customers.

Forecasting transmission charges paid to TNSPs

DNSPs incur transmission charges when a transmission network service provider (TNSP) delivers electricity to their distribution networks via its transmission network. The TNSPs set these transmission charges based on the revenue caps determined by the ACCC.

The ACCC is currently reviewing these revenue caps for 2004-09, and is considering the applications from the NSW TNSPs (TransGrid and EnergyAustralia). The TNSPs have set their transmission charges for 2004/05 based on the ACCC's draft decisions released in May

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165 This split of the network tariff into distribution and transmission was not required for the current regulatory period under the revenue cap.

166 The Tribunal sought stakeholder feedback on the methodology in its Issues Paper - *2004 Issues Paper for review of NSW electricity distribution service providers*, November 2002.

2004. The TNSPs will be resubmitting their forecast capital expenditure programs for assessment by the ACCC, and the final revenue cap decisions are due for release in April 2005, which will affect transmission charges going forward.[167]

Calculating avoided transmission use of system (TUOS) payments[168]

As embedded or distributed generators are usually connected directly to the distribution network, they do not need to use the transmission network to transport the electricity they generate. Thus, 'avoided TUOS' represents the transmission charges a DNSP would have had to pay, if it had received the equivalent amount of electricity from one of the state's main power stations.

The Code specifies that the full benefit of the avoided TUOS charge must be passed through by the DNSP to the embedded generator.[169] As these payments are based on the transmission charges that the DNSP would have incurred, the Tribunal believes it is reasonable to include these payments in the transmission recovery arrangements.

The Code also specifies the broad framework that DNSP must use when calculating the amount of avoided TUOS to be paid. This amount is to be based on the charges that it would have paid if the embedded or distributed generation project had not been connected to the network.[170]

For 2003 and 2004, the Tribunal published a guideline setting out a methodology for calculating avoided TUOS payments based upon the Code's broad framework. In its draft report, the Tribunal stated it intended to continue with this approach and would publish a guideline for 2004/05 onwards. It received no comments on this matter.

Therefore, for the 2004-09 regulatory period, the Tribunal has decided that where DNSPs calculate the payments in accordance with the separately published guideline, the actual payments made will be included as part of the transmission recovery arrangements and recovered via transmission cost recovery tariffs. The DNSPs will need to show evidence of their calculation. However, where the DNSPs adopt a methodology other than that outlined in the guideline, they will be required to demonstrate that the methodology is consistent with the Code. This will occur as part of the annual pricing compliance process, before the payments are included for recovery.

Forecasting inter-distributor transfer payments

Inter-distributor transfer (IDT) payments are made by one DNSP to another DNSP, operating in NSW or in another state, for conveying electricity through its distribution network. The Tribunal has included the costs of inter-distributor payments in the transmission recovery arrangements, as they are essentially payments to another service provider for delivering electricity to a DNSP's network. It makes little difference whether the electricity is delivered to the DNSP via another DNSP or a TNSP.

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167 ACCC, *Draft Decisions for TransGrid and EnergyAustralia transmission revenue caps*, 4 May 2004

168 In most cases, embedded or distributed generators are connected directly to the distribution network, and this means they do not need to use the transmission network to transport the electricity they generate. 'Avoided TUOS' represents the transmission charges that would have been payable on this electricity.

169 *National Electricity Code*, clause 5.5(h).

170 *National Electricity Code*, clause 5.5(i).

However, any *revenue* a DNSP receives from another DNSP for inter-distributor transfers will be treated as a revenue item in the weighted average price cap. This arrangement is similar to that in the 1999 regulatory period. There is little in-principle difference in receiving revenue from retailers or from other DNSPs—in both cases, payment is for carrying electricity to supply the other parties' customers.

13.3.3 DNSPs will record the difference between actual revenue and actual costs in a transmission overs and unders account

The Tribunal has affirmed its decision to use a transmission overs and unders account as part of the recovery mechanism, as it provides an audited record of the amount that the DNSPs need to recover (or repay) over time. This is particularly important given there is a two-year time lag between setting tariffs and the latest available actual data.

The transmission overs and unders account will record, at the end of each financial year, the difference between what the DNSP realised as actual revenue from the tariffs, and the actual transmission related payments it incurred. This difference is due to the fact that transmission cost recovery tariffs are based on forecasts—of transmission charges set by the TNSPs, and of the volumes to be sold. The account is a means of overcoming the timing issue in relation to when the prices are set and when the costs are incurred. The balance represents the amount of transmission-related revenue that the DNSP either needs to recover from customers, or return to customers in following years.

In the first year of the regulatory period, the transmission overs and unders account will have an opening balance equal to the forecast error arising from the difference between the actual 1999-2004 distribution unders and overs account balance for network tariffs for 30 June 2004, and the forecast of the balance included in the building blocks for the weighted average price cap. The Tribunal believes this is the most suitable way to address the forecast error. [171] EnergyAustralia expressed support for this approach.[172]

The balance of the transmission overs and unders account, plus any interest that has accrued,[173] may be recovered from transmission cost recovery tariffs in following years, provided the network tariffs remain within the network price limits. This is discussed more fully in section 13.3.4 below.

The rules governing the operation of the overs and unders account are contained in Clause 6 and Annexure 7 of the Tribunal's determination.

13.3.4 DNSPs can adjust transmission cost recovery tariffs to account for any over or under recovery, subject to price limits on network tariffs

To facilitate the recovery of any balance that may accrue in the transmission overs and unders account, the Tribunal decided that the DNSPs may adjust transmission cost recovery tariffs going forward by an amount that aims to return the account to zero.[174] This 'transmission recovery amount' will be set by the DNSP based on the balance in the transmission overs and unders account, and will be approved by the Tribunal during the

171 This issue is discussed further in section 6.5.
172 EnergyAustralia submission to the draft determination, 5 March 2004.
173 Any balance in the account will earn interest equivalent to the nominal WACC.
174 For the purposes of the determination, this amount will be called the 'Transmission Recovery Amount'.

annual pricing proposals process. However, the resulting transmission cost recovery tariffs will be subject to the price limits on total network tariffs.

In making this decision, the Tribunal considered various alternative correction mechanisms designed to ensure that the DNSP adequately recovers all its costs, including the approach adopted by ESC Victoria in its 2000-2005 distribution determination, the 'truing up factor' suggested by Country Energy in its submission in response to the Tribunal's draft determination, and the current approach used in the Tribunal's 1999 determination.

The approach outlined in the ESC's determination returns the actual difference over two years according to a formula, with no constraints. However, during the regulatory period, the ESC had to impose interim transmission rebalancing constraints, due to the unexpected impact transmission charges had on network prices. The Tribunal considers that some flexibility in the arrangements is required for the DNSPs and the regulator, to allow the DNSPs to recover or repay the differences over a period of time, taking into account future forecast balances or previous tariff changes. It believes the ESC approach is not suitable in light of the volume fluctuations experienced in NSW.

Country Energy proposed the use of a 'truing up factor' to account for the difference between forecast and actual transmission costs.[175] In the Tribunal's view, the primary difference between this approach and the one it has adopted is that Country Energy suggested that the 'truing up factor' should be passed through outside of the price limits. However, the Tribunal believes price limits on distribution tariffs are appropriate, to promote price stability and protect consumers from unacceptable price increases.[176] In addition, it believes it has provided adequate compensation in the form of interest on any transmission over or under recovery that may result from its approach (see section 13.3.3).

13.3.5 Tribunal may consider a departure from the price limits on network tariffs

The distribution unders and overs account in the 1999 determination required DNSPs to reduce or increase their network tariffs based on the balance of the account. However, due to unpredictable volumes and fluctuations, sizeable balances accumulated. In light of this experience, the Tribunal has developed new operating rules and has made provision for any unexpected balances accumulating in the account, through the rule – *Departure from the Price Limits* – outlined in Chapter 14.

As discussed in Chapter 14, the Tribunal believes the level of the network price limits will allow full recovery of transmission-related payments incurred each year. This is based on analysis of the forecasts of transmission charges and volumes. However, these price limits may become a binding constraint on DNSPs for some tariffs in any one year—for example, as a result of larger then expected increases in transmission charges, or significant forecasting errors. In these situations, the amounts unrecovered will remain in the transmission overs and unders account to be incorporated into the tariffs in the following year.[177]

175 Country Energy submission to the draft determination, 5 March 2004, p 128.

176 For more discussion on price limits on network tariffs, refer to Chapter 14.

177 Any balance will accrue interest equal to the nominal rate of return.

In the unlikely event that the balance in the account may not be recovered through transmission cost recovery tariffs in the remaining years of the regulatory period, the DNSPs may apply to the Tribunal to depart from the network price limits. The Tribunal will permit applications only if the forecast balance of the transmission overs and unders account accumulates to 15 per cent of actual transmission costs incurred in the previous year. The application procedure and factors the Tribunal will consider are set out in the rule -- *Departure from the Price Limits*— and is discussed in Chapter 14.

13.3.6 There will be no carry-over mechanism in the determination

Integral Energy requested that the Tribunal establish a carry-over correction mechanism, to provide regulatory certainty about the treatment of any balance in the transmission overs and unders account at the end of the 2004-09 regulatory period. The Code has provision for 'correction factors' arising from the previous regulatory period (clause 6.10.5(d)(8)), to be considered in future determinations. However, it does not specify how these correction factors should be treated.

In line with these provisions, the Tribunal believes that the treatment of the correction factors for matters relating to the 2004-09 regulatory period must be considered at the time of the next determination and cannot be formally specified in the 2004-09 determination. The Tribunal notes that any decisions it makes in this determination will not legally bind future regulators to a particular course of action.

However, the Tribunal has established the transmission recovery arrangements to ensure the DNSPs can recover their transmission-related costs. Based on this, it believes that the DNSPs should be entitled to recover any of these costs that have not recovered by the end of the regulatory period in the next regulatory period—just as they should be obliged to return any costs they have over-recovered to customers at this time. This is consistent with the views the Tribunal expressed in chapter 8, relating to the recovery of demand management-related costs.

14 SETTING PRICE LIMITS FOR NETWORK TARIFFS

The weighted average price cap limits the *average* change DNSPs can make to their network tariffs across all customers. This means they have considerable scope to restructure *individual* network tariffs within this overall constraint—and that customers could potentially face significant increases in individual tariffs. To protect customers from unacceptable price shocks, the Tribunal has imposed limits on the amount by which individual tariffs can increase in any one year. Price limits will be applied to total network tariffs - residential and non-residential, excluding cost reflective network pricing (CRNP) tariffs. Any tariff increases required above the limits, will need to be transitioned over more than one year.

For this determination, the Tribunal considered how it could apply such price limits in a way that balances the need to protect customers from price shocks with the need to provide the DNSPs with sufficient flexibility to restructure their tariffs. It also took into consideration the need to:

- enable the DNSPs to recover their efficient costs, as allowed for under the weighted average price cap
- facilitate the recovery of transmission charges from customers
- achieve cost reflective prices.

This chapter sets out the Tribunal's final decisions on the form and level of the price limits, and discusses its considerations in making its final decisions.

14.1 Final decisions

The Tribunal has decided that:

- **price limits will take the form of a weighted average of the tariff components, weighted by historical quantities or reasonable estimates of these quantities**
- **price limits will apply to total network tariffs (that is, aggregated DUOS and transmission cost recovery tariffs)**
- **price limits will apply to all residential and non-residential tariffs, except individually calculated CRNP tariffs**
- **price limits will apply across tariffs where there has been a compulsory transfer of customers, whether to new or existing tariffs**
- **an additional constraint will apply to the level of movement ($30) in any fixed charge component of residential tariffs**
- **the level of the price limit has been set exclusive of costs to be recovered via the cost pass through mechanism, however is inclusive of demand management costs to be recovered via the D-factor**
- **the allowable increase in residential and non-residential tariffs (L_{t+1}) will be as set out in Table 14.1.**

Table 14.1 Price limits for 2004-09[178]

DNSP	Price limit for 2004/05	Price limit for each year 2005/06-2008/09
ALL DNSPS	ΔCPI + 7.0%	ΔCPI + 4.5%
All DNSPs, each year	• Maximum increase in fixed charge of residential tariffs $30 per year • Zero nominal increase for miscellaneous charges and monopoly fees (after once only adjustment on 1 July 2004)	

In addition, the Tribunal has decided that it will consider waiving or increasing the price limits to allow DNSPs to recover transmission-related payments. This procedure is set out in the *Rule—Departure from Price Limits*.

14.2 Summary of draft decisions and stakeholder responses

The Tribunal's final decisions on the *structure* of the price limits for individual tariffs affirms its draft decisions. However, the Tribunal has amended the *level* of limits in the first year of the regulatory period from that suggested in the draft determination, to allow for the increases in the DNSPs X-factors.

In their responses to the draft decisions, the DNSPs generally accepted that price limits in some circumstances were appropriate, but expressed concerns about the proposed form and application of the limits:

- Some DNSPs opposed the decision to apply the price limits to total network tariffs, rather than to DUOS tariffs only, arguing that this would not facilitate the pass-through of transmission charges as provided for under the Code.
- Some also argued that the decision to apply the limits to non-residential tariffs as well as residential tariffs would restrict tariff reform initiatives to achieve more cost-reflective prices.[179] Integral Energy submitted that non-residential customers are already sufficiently protected by the weighted average price cap and the Tribunal's price setting arrangements.[180]

In relation to the level of the limits, the DNSPs were concerned that the proposals would:

- restrict their recovery of transmission charges, particularly in light of the increases requested by the NSW TNSPs for their next regulatory period, due to commence on 1 July 2004
- not facilitate tariff restructuring. Country Energy and Australian Inland requested additional headroom between the level of the limits and their X-factor for each year of the regulatory period to enable it to achieve its tariff reform.

178 Applies to each residential and non-residential tariff, excluding CRNP (cost reflective network pricing) tariffs and rebates.

179 Country Energy submission to the draft determination, 5 March 2004, p 137, EnergyAustralia submission to the draft determination, 5 March 2004, p 71.

180 Integral Energy submission to the draft determination, 5 March 2004, p 77.

Most non-DNSP stakeholders, on the other hand, supported the decisions to apply price limits to total network tariffs, and to both residential and non-residential tariffs. PIAC commented that applying the price limits to the total network tariff "…will ensure better price protection for customers and provide consistency with the 1999 determination. Both considerations are of value to residential customers".[181] However, PIAC was disappointed that the Tribunal had decided to apply the price limits to individual tariffs rather than customers' bills, as was applied under the 1999 determination.

PIAC also supported the decision to apply additional limits on the fixed charge components of residential tariffs.[182]

14.3 Tribunal's considerations in making its final decisions

In making its final decisions on the price limits, the Tribunal considered all stakeholder submissions, the principles and objectives of the Code and undertook its own analysis. The Tribunal's decisions seek to strike an appropriate balance between the needs of customers and those of the DNSPs. In particular, it believes that both the form and level of the limits provide the DNSPs with sufficient flexibility to recover their smoothed revenue requirements, restructure tariffs to improve cost reflectivity and to recover transmission-related costs. Its considerations in relation to each of its final decisions are discussed in detail below.

14.3.1 Price limits will take the form of a weighted average of tariff components

The Tribunal decided that the price limits will be structured so that the weighted average increase in the tariff components of an individual tariff cannot exceed the specified price limit. This means that the DNSPs will need to calculate the average price for a tariff under the previous prices, and the average price received for that same tariff under the new prices,[183] to determine whether the average price has increased by more than the price limit. This is represented as follows:

$$\frac{\sum_{j=1}^{m} r_j^{t+1} * q_j^{t-1}}{\sum_{j=1}^{m} r_j^{t} * q_j^{t-1}} \leq 1 + \Delta CPI + L_{t+1}$$

where:

the network tariff has up to *m* aggregate components (meaning the aggregate of any DUOS Tariff component and its corresponding Transmission Cost Recovery Tariff component)

r_j^{t+1} is the proposed price for aggregate component *j* of the network tariff for Year *t+1*

181 PIAC submission to the draft determination, 5 March 2004, p 2.

182 PIAC submission to the draft determination, 5 March 2004, p 1.

183 Assuming the same consumption.

r_j^t is the price charged by the DNSP for aggregate component *j* of the network tariff in Year *t*

q_j^{t-1} is the audited quantity of aggregate component *j* of the network tariff that was charged by the DNSP in Year *t-1* (or reasonable estimates where provided for compulsory transfers to new tariffs or existing tariffs)

L_{t+1} is the price limit for Year *t+1*

ΔCPI is the change in the Consumer Price Index over the 12-month period from January of the Year *t-1* to December of the year *t*, compared with the preceding 12-month period.

Under Part E of the Code, the jurisdictional regulator may place limits on the annual variation in distribution prices.[184] In the 1999 determination, limits on price movements were applied to customers' bills, rather than to individual tariffs. The Tribunal has taken the view that applying limits on individual network tariffs better meets the intent of the Code, rather than placing limits on movements in customer's bills.

The Tribunal noted PIAC's concern that removing the price limit from bills is less of a safeguard to individual customers. However, the Tribunal is of the view that applying the price limits to individual tariffs retains sufficient protection for customers whilst providing the DNSPs with the flexibility they need to restructure their network tariffs. The Tribunal has also supplemented these price limits with a limit on the increase in fixed charges for residential customers, discussed below.

Tariff restructuring is an important issue for at least two reasons:

- first, as a result of amalgamations of former businesses', DNSPs have a large number of tariffs that may be inconsistent and they need to rationalise[185]
- second, DNSPs may need to make tariffs more cost reflective, which requires them to restructure them so that the components reflect the costs being incurred, whether on a fixed, variable or time basis.

In the lead-up to the draft determination, the Tribunal considered applying price limits to each individual tariff component —for example, the usage charge and the fixed charge. However, it considers that this approach would be considerably complex, and would not provide DNSPs with sufficient flexibility to restructure the components within tariffs. Although it has placed a separate price limit on the fixed charge of residential tariffs, it considers the level is sufficient to facilitate tariff reform.

184 Clause 6.14.4. For the 2004/05-2008/09 determination, the Tribunal will not be replacing this clause with its alternative pricing methodology.

185 For Country Energy in particular, this is a major task requiring restructuring of tariffs to reduce the number of tariffs, and to reduce the disparities between similar customers who are on different tariffs depending on which former supply region they are located.

An additional constraint will be applied on the fixed charge component of residential tariffs

Under the weighted average price cap approach, DNSPs could make very large increases to the fixed charges by decreasing the volume-based charges. Any increase in the fixed charge component particularly affects low-income and low-consumption customers.

The Tribunal decided to apply an *additional* constraint to this component of all network tariffs for residential customers for protection from rapid price increases. Any increase in the fixed charge component of these tariffs must be accommodated within the overall price limits *and* cannot be more than $30 per year. This is similar to the price limits in the 1999 determination, under which residential customer bills could not increase by more than $30 per annum or 2 per cent (whichever was greater).

In making this decision, the Tribunal noted that none of the DNSPs submitted that this additional constraint would hinder tariff reform or cost recovery, and it was endorsed by PIAC.[186]

14.3.2 Price limits will apply to total network tariffs

The Tribunal decided to set price limits for total (or aggregated) network tariffs, rather than to set separate limits for DUOS tariffs and transmission cost recovery tariffs, or to apply limits to DUOS tariffs only. This approach is consistent with the 1999 determination. The aim of price limits is to mitigate potential price shocks to customers, which means protecting the aggregated network tariff, rather than leaving customers exposed to increases, or price shocks which could occur if some parts of the tariff are unprotected.

The Tribunal notes that the Queensland Competition Authority (QCA) applied side-constraints to the distribution tariff only, however during the regulatory period it required the distributors to limit the customer impacts of annual changes in TUOS prices. This was a result of significant changes in Powerlink's charging structure and in the method of pass-through used by the DNSPs. The QCA are now considering placing side-constraints on the TUOS tariff as well as the distribution tariff.[187] In Victoria, an overall tariff re-balancing constraint was applied to the network tariff in the first year of the regulatory period, and separate controls on each of the distribution tariffs and transmission tariffs were applied in each year of the regulatory period.

The Tribunal decided against applying multiple price limits – that is, a separate price limit on the DUOS tariffs, or transmission cost recovery tariffs, as well as the network tariff. The Tribunal is of the view that applying constraints in addition to the price limit on network tariffs would hinder the tariff reform which is required in NSW, without necessarily providing any supplementary protection to customers.

The Tribunal considered the DNSPs' concerns that applying the price limit to the total network tariff rather than to the DUOS tariff only would restrict their recovery of transmission-related costs. However, it believes that the transmission recovery arrangements outlined in Chapter 13 allow them to recover the transmission related costs over the regulatory period.

186 PIAC submission to draft determination, March 2004, p 1.
187 Queensland Competition Authority, *2005 Electricity Distribution Review Issues Paper*, September 2003, p 21.

14.3.3 Price limits will apply to all residential and non-residential tariffs, except CRNP[188] tariffs

The Tribunal decided that the price limits will apply to all residential and non-residential (business) network tariffs, excluding cost reflective network (CRNP) tariffs set individually for larger, non residential customers.[189] This represents a change from the 1999 determination, under which price limits applied to residential tariffs only.

Customer groups, and some DNSPs, supported continuing price limits for residential customers, particularly for low income customers.[190] The Tribunal acknowledges that many residential customers are protected by its price limits on the default retail tariffs until 1 July 2007, however those entering the competitive market are not, and price limits on network tariffs seeks to achieve a balance in this regard.

The Tribunal considered the DNSPs' concerns that extending the application of price limits to non-residential tariffs would unnecessarily restrict tariff reform. It was not sure whether this concern stemmed from a belief that non-residential customers with high end-use consumption can absorb higher increases, or that tariffs applicable to these customers are currently less cost-reflective and require greater reform than residential tariffs. However, it believes that the price limits on non-residential tariffs should not prevent the DNSPs from undertaking tariff reform, particularly as these limits provide sufficient headroom above the DNSP's X-factors to accommodate tariff restructuring (see section 14.3.5).[191]

In making this decision, the Tribunal took into account that there are many smaller non-residential customers whose consumption pattern is similar to residential customers'. It can see no reason why these customers should be treated differently to residential customers. In addition, it notes that as the price limits are in the form of a percentage increase, not a fixed dollar amount, those non-residential customers with higher consumption patterns will receive a proportionate increase.

Furthermore, the Tribunal notes that, in their current determinations, regulators in Queensland, Victoria and South Australia have applied price limits on network tariffs for non-residential customers.

Price limits will not apply to customers on CRNP tariffs

The Tribunal decided that the price limits will not apply to individually calculated tariffs based on the cost reflective network prices (CRNP) methodology.[192] The DNSPs usually provide these tariffs for very large customers.[193] The Tribunal does not believe it is appropriate to apply price limits to these tariffs, as they are calculated to reflect the specific costs associated with that customer. Should the customer request additional services or

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188 Tariffs set subject to the cost reflective network pricing methodology of the DNSP.

189 The CRNP process is a cost allocation mechanism based upon the structure of the present network using a fully distributed cost of supply analysis and is an assessment of long run incremental pricing for the individual assets used by the individual customer.

190 PIAC submission to the 2004 electricity network review, p 7, EWON submission on the *2004 Electricity Distribution Review – Preliminary Analysis – Secretariat Discussion Paper*, 20 October 2003, p 5.

191 With the exception of 2004/05.

192 This methodology is a cost allocation mechanism based on the structure of the present network using a fully distributed cost of supply analysis, and an assessment of long run incremental pricing for the individual assets used by the individual customer.

193 Where a large customer is usually regarded as consuming >10MW or 40GWh per annum.

require specific infrastructure, the price will reflect this. The customer can use the negotiation frameworks required to be established under clause 6.14.7 of the Code, to negotiate with the DNSP in setting these prices, which includes dispute resolution procedures. This is also discussed in section 15.3.6 of this report.

During this review, the Energy Markets Reform Forum also put the view forward that imposing price limits on any customers, could have adverse impacts on those customers where the price limit is not applied. It argued that the DNSPs could increase their level of cost recovery by increasing the tariffs not covered by price limits, while remaining within the regulatory constraints of the weighted average price cap.[194] The Tribunal does not agree with this view as the DNSPs are required to adhere to the pricing principles when allocating costs and setting prices.[195] These aim to ensure prices are reflective of the costs incurred, and that there are no cross-subsidies between customer groups.

14.3.4 Price limits will apply across tariffs where compulsory transfers occur (onto new tariffs or existing tariffs)

Three of the DNSPs have said that they intend to create new tariffs, change the structure of existing tariffs, and will transfer customers to alternative tariffs during the coming regulatory period. The Tribunal's draft report did not make it clear whether it intended the price limits to apply across tariffs, such as when a DNSP sets new tariffs or transfers customers to alternative tariffs (that is, whether the limit applies to the difference between the customer's original and new or replacement tariff). During the 1999 regulatory period, customers were protected in these circumstances as the price limit applied to the individual customer's bill, and limited the annual variation in this bill, regardless of the tariff he or she was on.

For the 2004-09 regulatory period, the Tribunal decided that price limits will apply across tariffs *only* when a DNSP mandatorily transfers a customer to another tariff, whether that is a new tariff or an existing tariff. In these situations, the DNSP must calculate the average price change between the original (origin) tariff and the alternative (replacement) tariff, and ensure that any price increase complies with the price limits. The price limits will *not* apply when a customer voluntarily transfers to another tariff. The Tribunal believes that customers who transfer voluntarily do so at their discretion with the knowledge of what to expect on the new tariff.

The Tribunal considered EnergyAustralia's suggestion that, for customer transfers, the weighted average should be applied across a group of related tariffs, rather than to an individual tariff. This would enable them to increase one tariff (for example, the domestic time-of-use tariff) by more than the level of the price limit, and offset this increase with a reduction in another domestic tariff (such as the flat rate tariff).

However, the Tribunal believes that this approach would not protect customers from price shocks, particularly where the tariff has a small number of customers on it and large increases could be absorbed within a weighted average increase. The Tribunal believes its provisions ensure that every customer is treated in the same manner and is subject to the same price limit. Application of the formula is explained in more detail in Appendix 5.

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194 EMRF comments on the Secretariat's Preliminary Analysis Paper, 9 October 2003.

195 The pricing principles are set out in Appendix 10 of this report.

14.3.5 Setting the level of the price limits

To improve transparency, the Tribunal decided to set common price limits for all DNSPs. As shown in Table 14.1, it has set the price limits (or the value of the L-factor) at the change in the CPI+7% for 2004/05 and at the change in the CPI+4.5% for each of the remaining years in the regulatory period. For EnergyAustralia, Australian Inland and Country Energy, these limits are equal to their X-factors for 2004/05, and are at least 2 per cent above their X-factors for the rest of the regulatory period. For Integral Energy, the limits are at least 2 per cent above its X-factors for each year of the regulatory period.

The Tribunal decided to set equal limits for both residential and non-residential tariffs. In Victoria and South Australia, there is also no differentiation between the level of the limits for residential and non-residential customers.

In making these decisions, the Tribunal aimed to balance the needs of customers with those of the DNSPs. It also took into account the following factors:

- to enable the DNSPs to recover the revenue allowed under the weighted average price cap, the price limits must be at least equal to the X-factors
- to facilitate tariff restructuring, the price limit must provide some 'headroom' above the X-factors, so that some network tariffs can be increased by more than the average level (and would be offset by a reduction in other tariff levels)
- to ensure the full recovery of transmission charges, the price limit needs to be at least equal to the average increase in transmission charges set by the TNSPs.

The Tribunal's considerations in relation to each of these factors are discussed below.

Level of price limits will allow the DNSPs to recover smoothed revenue requirements

The Tribunal recognises that if the DNSPs are to recover their smoothed annual revenue requirements, they need to be able to increase individual tariffs by the amount by which their average prices can rise under the weighted average price cap (their X-factor). In setting the price limits, the Tribunal has ensured that the price limits for individual tariffs are at least equal to each DNSP's X-factor for each year of the regulatory period.

Level of price limits is sufficient to allow for tariff restructuring

If the DNSPs are to recover their smoothed revenue requirements while *also* rebalancing network tariffs, they need to be able to increase individual tariffs by more than their X-factor. This 'headroom' provides them with the flexibility to increase some tariffs by more than the X-factor, while still complying with the overall cap on average price increases.[196]

The Tribunal has not provided any headroom for EnergyAustralia, Country Energy and Australian Inland in the first year of the regulatory period. It believes that, given the size of their X-factors for this year, doing so would have created the potential for unacceptably large price increases for some customers. This means that these DNSPs will not be able to increase some tariffs by more than the X-factor in this year. But they can still change the components within an individual tariff (for example, by introducing new tariff components or changing

[196] For example, they can increase some tariffs by more than the X-factor, and reduce other tariffs or increase them by less than the X-factor to arrive at an average price increase that complies with the weighted average price cap.

time bands). In addition, should the average increase in transmission charges paid to TNSPs, be less than the price limit, they can use this differential to facilitate DUOS tariff changes, if required for cost reflectivity. [197]

As a result of setting common price limits across the DNSPs, Integral Energy receives 2 per cent headroom in the first year of the regulatory period as its X-factor is lower. The Tribunal did not see any reason to differentiate between maximum price increases in Integral's area compared to other areas in NSW.

In the remaining years of the regulatory period, the Tribunal has provided all DNSPs with at least 2 per cent headroom above their X-factors. In making this decision, it considered Country Energy's request for 4 per cent headroom in each year of the regulatory period. As it noted in its draft report, it is sympathetic to Country Energy's situation. This DNSP has a large number of the tariffs inherited from former electricity businesses that are not cost reflective. However, it considers that large price increases for specific customer groups cannot be justified or sustained in each year of the regulatory period.[198] The Tribunal encourages Country Energy to progress with its tariff reform and tariff amalgamations; however, it must allow a longer timer frame within which to meet its objectives.

The Tribunal also considered Australian Inland's request for more headroom. As noted above, it believes the DNSP's X-factor for 2004/05 is too large to allow higher increases in individual tariffs in this year. It also believes that the 2 per cent headroom provided for 2005/06 to 2008/09 provides sufficient flexibility to facilitate reasonable progress towards its tariff reform objectives.

Level of the price limits provides for increases to transmission charges as proposed in the ACCC's draft decisions for the NSW TNSPs

The Tribunal recognises that to ensure the full recovery of transmission charges, the price limits on individual tariffs need to be at least equal to the average increase in the transmission charges the DNSPs pay to the TNSPs. The price limits it has set will accommodate an average real increase in transmission charges of up to 7 per cent in 2004/05, and 4.5 per cent real in each year from 2005/06– 2008/09. Any increases in any one year above this level will be accommodated through the transmission overs and unders account, and the *Rule – Departure from Price Limits* (see section 14.3.6).

Actual increases in transmission charges will be determined by the revenue caps set by the ACCC for the NSW TNSPs, TransGrid and EnergyAustralia.[199] New revenue caps for each of these businesses are due to commence on 1 July 2004. When the Tribunal released its draft determination, the ACCC had not released its draft decision on these caps. However, EnergyAustralia had proposed increases of 32.4 per cent in 2004/05 and 6.8 per cent in each of the following years to 2008/09. TransGrid had proposed increases of 12.7 per cent in 2004/05 and 2 per cent in each of the following years.

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197 For example, if the price limit on total network tariffs is 7 per cent, and the average increase in the transmission cost recovery tariffs is 5 per cent, the DNSP can use this differential to increase the DUOS tariff by more than 7 per cent, as long as the average increase in the total network tariff remains at 7 per cent or less.

198 This is notwithstanding the fact that Country Energy has some support from customer groups to achieve its tariff reform objectives outside of the price limits. See PIAC's comments in Country Energy's submission to the draft determination, 5 March 2004, p 131.

199 Australian Inland and Country Energy also incur transmission charges from interstate transmission service providers who also have revenue caps set by the ACCC.

The ACCC has since released its draft decision, which provides for real increases in 2004/05 of around 13 per cent for EnergyAustralia and around 3 per cent for TransGrid. When the market share of each of these TNSPs is taken into account, the weighted average increase in the transmission charges paid by the NSW DNSPs will be around 4.5 per cent (real) for 2004/05. While the Tribunal acknowledges that some sections of the distribution network, particularly in the rural areas, may see increases greater than this weighted average, it is confident that the price limits it has set for this year will accommodate the proposed transmission charges increases.

For the remaining years of the regulatory period, the ACCC has proposed real price increases of 3.5 per cent per annum for TransGrid and 1 per cent per annum for EnergyAustralia. This suggests that the weighted average increase for the DNSPs will be around 1.5 per cent per annum for 2005/06-2008/09. The Tribunal recognises however that both the TNSPs will be resubmitting their applications for forecast capital expenditure, which may impact on the ACCC's final decision. The Tribunal's price limits for 2005/06 to 2008/09 will accommodate average real increases in transmission charges up to 4.5 per cent per annum.[200]

14.3.6 The Tribunal will consider departing from the price limits if a DNSP's transmission overs and unders account balance becomes too large

The Tribunal decided to provide for the price limits on network tariffs to be waived or increased in the event that a DNSP accumulates a large balance in its transmission overs and unders account. In making this decision, the Tribunal took into account the forecast risk associated with volumes and transmission charges. It also took into account the DNSPs' concerns that price limits on network tariffs could restrict their recovery of transmission charges, and other stakeholders' concerns that large overs and unders account balances create regulatory uncertainty. It notes that its 1999 determination included a similar condition, for transmission price changes which resulted from the expiration of the derogation on transmission pricing,[201] and that similar arrangements have been utilised in other states.[202]

The *Rule – Departure from Price Limits* allows the Tribunal to authorise a DNSP to depart from the network price limits in order for the DNSP to recover a significant balance in the transmission overs and unders account. The DNSPs will be able apply for a departure from the price limits when the balance in the account is forecast to reach an amount equivalent to 15 per cent of the actual transmission costs they incurred in the previous year (the 'trigger' point). Their application will need to demonstrate that they will not be able to recover their overs and unders account balance in the remaining years of the regulatory period within the network price limits. The Tribunal will consider these applications on a case-by-case basis.

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200 Any larger increases must be accommodated via the Rule – Departure from Price Limits.

201 IPART, *Regulation of NSW Electricity Distribution Networks, Determination and Rules,* December 1999, p 22.

202 For example, the Essential Services Commission of Victoria relaxed price limits in 2002 and 2003 to accommodate transmission charge increases

Departure considered when transmission overs and unders account balance forecast to be greater than 15 per cent of actual transmission charges in previous year

The Tribunal decided to set the point at which it would consider a departure application, when the balance in the account reaches 15 per cent of actual transmission charges for the previous year, rather than 20 per cent as proposed in the draft rule.[203] The Tribunal took into consideration the fact that the balance in the transmission overs and unders account for EnergyAustralia at the 20 per cent trigger point could be above $30 million,[204] and Country Energy or Integral Energy's could be above $20 million.[205] The Tribunal considers that it would not be acceptable for amounts close to these to remain in the overs and unders accounts at the end of the regulatory period if the DNSP does not quite reach the 20 per cent and is not eligible for a departure. This is despite the fact that most of the DNSPs analysis indicated that they would not reach the 20 per cent trigger point during the regulatory period and hence would not need a departure application.[206]

The 'trigger' point of 20 per cent was set high enough to avoid departure applications being received in consecutive years, firstly due to the uncertainty it creates for prices, and secondly because there is considerable headroom in the network price limits in years 2-5 to recover any balances. EnergyAustralia and Country Energy's over-riding concern regarding the 'trigger point' of 20 per cent is that it delays their recovery when they believe they should be allowed an 'immediate' pass through under the Code.

EnergyAustralia proposed a trigger point of 10 per cent, with a forward looking test where price limits would be relaxed if at any time the forecast pricing outcomes suggest the 08/09 balance of the overs and unders account would not be recovered. The Tribunal's rule does have this as one of the factors it will consider when deciding whether a departure is required, however it is not the primary trigger as there is considerable uncertainty regarding forecast volumes and charges, particularly where the time horizon extends past one year.

Tribunal will assess departure applications on a case-by-case basis

Under the *Rule – Departure from Price Limits*, the Tribunal can decide to waive the price limit in any one year, or to increase the L-factor, to enable the DNSP to recover the balance of its transmission overs and unders account. Integral Energy and Country Energy requested further information and certainty on the Tribunal's process for deciding whether a departure will be granted and to explain clearly the method it intends to use to adjust the balance to zero.[207] However, the Tribunal considers that it is appropriate for it to assess applications on case-by-case basis, as its decision will depend on a range of factors, including:

- the number of years remaining in the regulatory period
- the forecasts of transmission-related payments and volumes for subsequent years

203 The Draft Rule- Departure from Price Limits was released with the draft determination, 9 January 2004.

204 Forecast TUOS line costs and inter-distributor receipts for 2004/05, $162m*20%.

205 Country Energy submission to draft determination, March 2004, p 136. Integral Energy's amount is calculated by forecast TUOS line costs and inter-distributor receipts for 2004/05, $107m*20%.

206 In the draft report, the DNSPs were asked to provide their analysis to demonstrate whether they expect to reach 20 per cent in any year of the regulatory period. EnergyAustralia's initial analysis indicated that the trigger point would not be reached (information provided at a meeting 13 February 2004), and Integral Energy considered it unlikely that the accumulated balance of the overs and unders account would reach such substantial levels by the end of the regulatory period (Submission to the draft determination, 5 March 2004).

207 Country Energy submission to the draft determination, 5 March 2004, p 128; Integral Energy submission to the draft determination, 5 March 2004, p 137.

- the size of the balance relative to the size of the DNSP's volumes and
- the likely price increases required to recover this balance.

The Tribunal envisages that, when it receives an application, it will determine how much of the balance of the overs and unders account can be recovered in each remaining year of the regulatory period without resulting in unacceptable outcomes for customers.

14.3.7 Price limits are inclusive of demand management costs, but exclusive of cost-pass through costs

The Tribunal has decided to set the price limit exclusive of its cost pass-through mechanism, however it is of the view that the price limits are sufficient to accommodate any D-factor costs or congestion pricing tariff initiatives introduced by the DNSP. The Tribunal's considerations in incorporating D-factor costs within the price limits is discussed in Chapter 8. The application of the price limits exclusive of the cost pass through mechanism is discussed in Chapter 11.

The Tribunal's reasons for not departing from the price limits for congestion pricing, remain the same as provided in its draft report. In it submission to the draft report, Country Energy requested flexibility to support congestion pricing.[208] Integral Energy on the other hand, believed the limits it was provided with, were sufficient.[209]

The Tribunal considered a report it commissioned to address avoided distribution costs and facilitate trials of congestion pricing by the DNSPs.[210] In this report, the consultant argued that the Tribunal will need to consider 'relaxing side constraints where these are inhibiting the ability to send meaningful congestion prices'.

The Tribunal's view is that the structure of the price limits as the weighted average of tariff components —provides DNSPs with sufficient flexibility to restructure tariffs to provide sharper signals of congestion costs. The SKM report found that the average price for constrained end-users should not rise by an unreasonable amount, with any increase in peak charges offset as far as possible by a corresponding decrease in off-peak charges.[211] This would suggest that the Tribunal would not need to provide special considerations for price limits on congestion prices.

14.3.8 The price limit for miscellaneous and monopoly service charges is zero

The Tribunal has determined an exhaustive list of maximum charges for miscellaneous services and mandatory charges for monopoly services. These charges apply from 1 July 2004 and are fixed for the regulatory period (see Chapter 9). To reflect this, the Tribunal has set a zero nominal price limit for charges for miscellaneous and monopoly services, which requires DNSPs to maintain these charges at their 1 July 2004 values.

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208 Country Energy submission to the draft determination, 5 March 2004, p 137.

209 Integral Energy submission to the draft determination, 5 March 2004, p 65.

210 SKM, *Reducing Regulatory Barriers to Demand Management, Avoided distribution costs and congestion pricing for distribution networks in NSW, Final Report*, November 2003, p 73.

211 ibid, p 52.

15 PRICE SETTING ARRANGEMENTS FOR NETWORK TARIFFS

Part E of Chapter 6 of the Code establishes a methodology for setting prices and tariffs for prescribed distribution services. As part of the 2004-09 determination,[212] the Tribunal has adopted an alternative pricing methodology, as permitted under clause 6.11(e) of the Code. The methodology was developed in consultation with stakeholders in the electricity industry, and preserves the principles established in the *Pricing Principles and Methodologies for Prescribed Electricity Distribution Services*[213] (PPM) which applied during the 1999-2004 regulatory period.

The alternative methodology's approach to price setting is based on the following key propositions:

- prices cannot be set by simply using a mechanical model—judgement is required.
- DNSPs should be responsible for translating the overall price caps set by the Tribunal into network prices, as they have a greater understanding of their customers and costs.
- DNSPs should be accountable for their pricing decisions through public disclosure of their costs and pricing strategies.
- the Tribunal will be able to reject network price changes where the network prices are inconsistent with the Tribunal's determination.

This chapter sets out the Tribunal's final decisions on the alternative pricing methodology, and the arrangements the DNSPs must follow when setting prices and making tariff changes. It also summarises the draft decisions and stakeholder responses and discusses the Tribunal's considerations in making its final decisions.

The Tribunal appreciates the involvement of the Pricing Issues Consultation Group[214] in developing the pricing arrangements.

15.1 Final decisions

The Tribunal has developed an alternative pricing methodology to apply instead of clauses 6.11 – 6.14.3 of Part E of the Code. Under this alternative methodology:

- **Price changes will occur once a year on 1 July[215] and the DNSPs are required to provide annual pricing proposals to the Tribunal for assessment against the requirements of the determination, including the weighted average price cap formula, transmission recovery arrangements and price limits on network tariffs.**
- **When setting prices, the DNSP must have regard to the pricing principles set out in the determination, which address the objectives of the Code.**
- **The DNSPs must publish a Network Strategy Statement at the beginning of the regulatory period and provide an Annual Pricing Report for the public at the time of annual price changes.**

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212 Largely set out in Section 12 of the 2004-2009 Determination.

213 Released in March 2001.

214 The Pricing Issues Consultation Group was established by the Tribunal for consultation on pricing issues in relation to the 2004-2009 distribution review. A list of members and meetings held is set out in Appendix 9.

215 There is provision for an additional price change date to be agreed with the Tribunal.

- **The DNSPs must undertake public consultation on proposals to change tariff structures, for the introduction of new tariffs, and on proposed changes to the Network Strategy Statement.**
- **If a DNSP fails to submit a compliant pricing proposal, default pricing arrangements will be implemented.**

15.2 Summary of draft decisions and stakeholder responses

The Tribunal's draft decisions on the price setting arrangements were largely the same as its final decisions. In their responses to the draft decisions, stakeholders generally supported the approach of leaving price setting in the hands of the DNSPs, subject to strengthening the information disclosure requirements and introducing public consultation. However, some DNSPs expressed opposition to some of the proposed arrangements, particularly in relation to public consultation (discussed in section 15.3.4) and the default arrangements (discussed in section 15.3.5).

The draft decisions were made after consultation with the Pricing Issues Consultation Group (PICG), which the Tribunal formed to review the 1999 PPM.[216] During this review process, there was considerable debate about whether the Tribunal should have a greater role in determining and approving price structures. Some stakeholders felt that the Tribunal should be more involved in the price setting process, given that the weighted average price cap embodies different incentives for pricing than the revenue cap in the 1999 determination. PIAC summed up this view in a supplementary submission to the review, noting that it was "…very concerned that both retailers and distributors can propose and implement radical restructuring of tariffs with little scope for the Tribunal or customers to scrutinise their merits".[217]

However, on balance, there was general consensus among the range of stakeholders represented on PICG that the DNSPs should continue to be largely responsible for setting prices, as they are under the existing PPM. For example, the Energy Users Association of Australia emphasised that it did not want the Tribunal to micromanage distribution tariffs, but for the regulator to take steps to resolve any disputes about monopoly pricing abuse and provide some guidance on what would constitute such abuse[218].

15.3 Tribunal's considerations in finalising the price setting arrangements

The Tribunal decided to adopt an alternative methodology to Part E of the Code based on the framework established under the existing PPM. It is of the view that an alternative methodology is needed, primarily because the pricing approach in Part E appears to be restrictive and (in some parts) inconsistent with the broader objectives and principles for distribution pricing embodied in the Code.[219] The existing PPM has achieved a substantial

216 A list of members is set out in Appendix 9.
217 PIAC supplementary submission to 2004 Review, October 2003 p 3.
218 EUAA submission to 2004 Issues Paper, July 2003, p 16.
219 For more discussion on this, refer to IPART, *Pricing for Electricity Networks and Retail Supply, 12A Report,* June 1999; the 1999 Determination; and PPM document.

degree of acceptance with stakeholders and has been referenced in other Australian jurisdictions in recent years.[220]

In deciding the price setting arrangements, the Tribunal considered its own and many stakeholders' views that the DNSPs should be responsible for setting prices, given that they are best placed to understand the relationship between costs and customers, which is essential for efficient prices. It also considered PIAC's and other stakeholders' concerns about the need for greater scrutiny of price setting, particularly in light of expected tariff reforms. To provide this scrutiny, the Tribunal has strengthened the annual compliance process, increased information disclosure requirements and introduced public consultation on pricing. These changes reinforce the transparent process underlying the existing PPM, under which the DNSPs must justify changes to tariffs in light of pricing objectives.

The arrangements that DNSPs must follow when setting prices and making tariff changes during the 2004-09 regulatory period are described below. Note that the Tribunal has also imposed price limits on individual network tariffs, which are discussed in Chapter 14.

15.3.1 DNSPs must provide annual pricing proposals to the Tribunal for assessment

As part of the alternative methodology for 2004-09, the DNSPs must submit annual pricing proposals to the Tribunal. It will then assess these proposals to ensure that:

1. proposed DUOS tariffs meet the weighted average price cap control formula
2. proposed 'transmission cost recovery tariffs' satisfy the requirements of the transmission recovery arrangements
3. miscellaneous charges and monopoly fees are levied in accordance with the determination
4. proposed price increases do not exceed the price limits on network tariffs
5. proposed network tariffs comply with the pricing principles,
6. the DNSPs have complied with the information disclosure requirements and public consultation procedures
7. any other conditions in the determination are met.

If a DNSP's pricing proposal does not comply with the above, default pricing arrangements will be initiated (see section 15.3.5).

Timeline for annual pricing proposals 2004/05

Due to the timing of the release for this determination, and the ACCC's draft decision on transmission charges, annual price changes commencing 1 July 2004 are subject to a particularly constrained timetable. The DNSPs are required to provide the Tribunal with their annual pricing proposals and draft annual prices report within a week of the release of this determination. These proposals will be made public. The Tribunal will then assess the pricing proposals for compliance, and the DNSPs will be required to make the prices and annual prices report available to the public prior to their commencement on 1 July 2004.

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220 For example, see the network pricing principle statements provided by the distribution businesses to the Queensland Competition Authority.

Timeline for annual pricing proposals process 2005/06 – 2008/09

DNSPs will be required to submit their pricing proposals to the Tribunal in early April each year,[221] with their draft annual pricing report. Public consultation for new tariffs or changes to the structure of existing tariffs will need to have occurred prior before this date. This timetable enables distribution service prices and the annual prices report to be published by 31 May each year at the latest, for prices to commence on 1 July. It provides for price changes once a year only, to achieve stability and certainty for customers and retailers.

The Tribunal has increased the lead-time for the provision of annual pricing proposals from the 1999 determination primarily to address the needs of:

- standard retailers, which are required under the retail determination to give the Tribunal 30 days notice of their default retail tariffs commencing 1 July
- second tier retailers, which may be required to make changes to their billing systems, particularly if there is a change in the structure of a tariff, or a new tariff being offered
- large users, which need to receive as much prior notice of price changes as possible, so they can incorporate them into their budgets and forthcoming business decisions.

This timetable was proposed in the draft determination after consultation with the Pricing Issues Consultation Group, and received support from DNSPs and non-DNSPs in submissions to the draft determination.[222]

15.3.2 DNSPs must have regard to the pricing principles set out in the determination

The pricing of prescribed distribution services involves allocating the costs that underlie those services and formulating prices to recover those costs. It requires a detailed understanding of cost structures, the needs of users and their sensitivity to price signals, the level of network utilisation, and the likelihood of the emergence of congestion. The Tribunal believes the DNSPs have the greatest knowledge of these matters and hence are in the best position to determine prices.

Nevertheless, important regulatory issues arise from the exclusive position of DNSPs in providing access to the electricity network, and as a monopoly body in setting prices. The Code recognises the importance of providing a mechanism for managing these, and other effects, and sets out objectives for the economic regulation of distribution pricing, which translate into economic efficiency, revenue sufficiency and equity.

When setting prices under this determination, the DNSPs are required to have regard to the pricing principles set out in Appendix 11 of this report, which aim to guide them in addressing the objectives of the Code. These pricing principles are broadly the same as those included in the 1999 PPM[223], which appear to be well regarded by stakeholders.

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221 See the timetable in Annexure 15 of the 2004-09 Determination.

222 AGL Sales & Marketing submission to the draft determination, March 2004; Country Energy submission to the draft determination, March 2004, p 140.

223 Minor amendments have been made to reflect the change in the form of regulation.

DNSPs' proposed tariff reforms

EnergyAustralia proposed a range of tariff reform initiatives and sought the Tribunal's endorsement of these proposals.[224] However, in line with the alternative price methodology, the Tribunal is of the view that it is not its role to direct or endorse tariff reform. Under the determination's price setting arrangements, the DNSPs will not need the Tribunal to 'approve' any tariff changes, or new tariffs. Rather, they will be required to demonstrate to the Tribunal and the public that in setting tariffs they have had regard to the pricing principles, and that they meet the information disclosure and public consultation requirements of the alternative price methodology.

This applies particularly to Integral Energy and EnergyAustralia's proposals to introduce inclining block network tariffs for residential and general supply customers from 1 July 2004. Some stakeholders remain unconvinced about the DNSPs' cited benefits of the inclining block tariff. However, Integral Energy and EnergyAustralia highlight that the inclining block tariff is but one of a suite of measures aimed to address the growing problem of air-conditioning and peak demand.[225]

15.3.3 DNSPs must publish a Network Strategy Statement and provide an Annual Pricing Report

Each DNSP is required to publish a network strategy statement at the beginning of the regulatory period, and publish an annual pricing report at the start of each remaining year of the period. These documents replace the annual Price and Service Report, which DNSPs were required to produce under the 1999 PPM.

The Tribunal recognises that the information in the Price and Service Report was very useful to stakeholders. However the size of these documents was daunting, and the time of their release (well after annual prices came into effect) was unhelpful. It therefore decided to require the DNSPs to disclose this information in two separate documents. This approach preserves the information available in the public domain, while ensuring sufficient focus is placed on the impacts of customers and up-coming changes.

The revised format was developed in consultation with the Pricing Issues Consultation Group and stakeholders who commented on this format in submissions during the review, supported it. For example, PIAC noted that it welcomed the revised regime for the disclosure of relevant pricing information by the DNSPs[226] and gave its full support to information disclosure framework.[227]

Network Strategy Statement

Each DNSP is required to disclose the information set out in Annexure 14 of the determination in a Network Strategy Statement. This information includes the DNSP's medium-term pricing strategies indicating the direction of prices for each customer class, its tariff setting process, and cost allocation methodologies. Each DNSP is also required to

224 EnergyAustraila submission to the draft determination, 5 March 2004, p 11.

225 The DNSPs analysis may be found on the IPART website under the '2004 Pricing Issues Consultation Group' heading. The report on T*he Impact of Air-conditioning on Integral's Network'*, by Charles River Associates and commissioned by Integral Energy may be found on Integral Energy's website. Also see the Secretariat discussion paper *Inclining Block Tariffs for Electricity Network Services*, July 2003.

226 PIAC submission to 2004 Review Issues Paper, July 2003, p 8.

227 PIAC supplementary submission to 2004 Review, October 2003 p 3.

explain the extent to which its prices incorporate the pricing principles and how they relate to the expenditure programs and service standards levels proposed over the regulatory period.

The Tribunal recognises that when the Network Strategy Statement is prepared, the DNSP may not have fully developed their tariff proposals for later in the regulatory period. More specific details on the tariff changes and the introduction of new tariffs, must be provided in the year prior to the change via the public consultation process and the Annual Prices Report.

While the Network Strategy Statement aims to provide customers with an indication of pricing directions for the regulatory period, the Tribunal also recognises that price setting is not a static process. Economic conditions and new information can affect pricing decisions. For this reason, DNSPs will be able to amend their Network Strategy Statements during the regulatory period, to reflect changes to their pricing procedures, cost methodologies or strategies.

However, they will be required to undertake a public consultation process on any proposed changes. The Tribunal believes it is important that stakeholders are given sufficient notice and an opportunity to provide input if tariff reform proceeds in a different way to that outlined in the Network Strategy Statement. This is particularly important if the proposed changes, particularly to costing methodologies, have implications for tariff levels, including individually calculated (CRNP) prices for large customers.

The draft determination proposed that the DNSPs release a draft Network Strategy Statement by 31 May 2004, and the final statement on 30 September 2004. The Tribunal acknowledges that this timeline will not provide the DNSPs with sufficient opportunity to consider all relevant information for their medium-term strategies.[228] For this reason, it has extended the due date of the final Strategy Statement until 30 October 2004. The DNSPs must release a draft statement prior to this and allow at least 30 days for the receipt of stakeholder submissions on the draft statement.

Annual Pricing Report

The DNSPs are required to publish an Annual Pricing Report, primarily to explain to customers their network tariffs, and any changes they have made to the prices. This report is to be released at the same time as annual price changes are announced.

The aims of the report are:

- To summarise the price setting process and the basis of network tariffs
- To advise customers of up-coming changes in a timely manner. The intention is to place more information into the public domain in regard to new tariffs and the purpose of tariff changes.
- To explain the likely impact the tariff changes will have on customers' bills. This information has previously not been available in any detail or has been provided to customers after price changes have occurred.

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228 Given the time of release of the final IPART determination, and the ACCC transmission revenue cap decisions for NSW.

15.3.4 DNSPs must undertake public consultation on changes to tariff structures, new tariffs and changes to the Network Strategy Statement

The Tribunal decided to require the DNSPs to undertake public consultation prior to submitting proposals to introduce new tariffs, change their existing tariff structures, and amend their Network Strategy Statement. DNSPs are required to establish a Register of Interested Parties. Organisations or individuals on this list will be contacted at the time of the tariff proposals, and will be able to make submissions to the DNSP in response to their proposals. These new arrangements were developed in consultation with the Pricing Issues Consultation Group and proposed in the draft determination. They were not required under the 1999 determination or included in the 1999 PPM.

These arrangements were developed in response to stakeholders requests throughout the 2004 review process, for more information disclosure and transparent decisions. Second tier retailers and customers expressed frustration that tariff changes have occurred in the past and they have had no opportunity to contribute any information to the process, and have had little notice of the impact the change will have on their business.

The Tribunal considered EnergyAustralia's and Country Energy's opposition to these requirements. However, it notes that most of the DNSPs acknowledged that they already undertake informal public consultation with customer councils and customer representative groups at the time of the annual pricing proposals. It believes that formalising this process will benefit the industry as a whole.

The Tribunal also notes that the consultation that occurred on the DNSPs' pricing strategies during the 2004 review process appeared to be helpful. Public scrutiny and stakeholder input increased the information available to DNSPs, and in some cases, lead to them re-evaluate their pricing strategies. Importantly, the pricing decisions were made transparent and stakeholders were provided with timely information regarding the proposed prices changes. The Tribunal is of the view that public consultation is a reasonable process, and avoids the need for the Tribunal to micro-manage tariff reform.

15.3.5 If DNSPs fail to submit a compliant pricing proposal, default pricing arrangements will apply

The Tribunal has decided to provide for default pricing arrangements in the event that a DNSP does not submit a compliant pricing proposal in any one year. However, it expects that this will occur only in exceptional circumstances.

The draft determination set out default arrangements largely in line with those used in the *1999 Pricing Principles and Methodologies*. That is, if the Tribunal did not receive a complying annual pricing proposal the Tribunal would have the discretion to set prices based on the direction implied by the DNSPs' weighted average price cap.[229] It would also have the discretion to allow the DNSP to change these prices based on a future complying proposal.

229 For example, if $CPI + X < 0$, the Tribunal would decrease prices by this amount.

Some stakeholders did not support these arrangements, arguing that they created uncertainty and allowed more than one price change in a year.[230] The Tribunal considered these concerns and decided to revise these arrangements so that no price changes will occur until the DNSP provides a complying proposal, and that any change thereafter will be at the discretion of the Tribunal. As each DNSP's X-factor is positive, the Tribunal is of the view that this should be incentive enough for the DNSP to submit a complying proposal.

15.3.6 Implications for large customers and CRNP tariffs

In general, large customers[231] are charged for electricity based on an individual tariff, determined using the cost reflective network price (CRNP) methodology set by the DNSP. This methodology allocates the cost of the service to the customer based on their location, consumption and load profile. CRNP tariffs are covered by the Tribunal's determination as they are charges for the provision of prescribed distribution services.

During the 2004 consultation process,[232] large customers on CRNP tariffs commented that it is currently very difficult to obtain any information about the costs that DNSPs have allocated to them, and changes to their tariffs, and to distinguish any changes in the pricing methodology from changes in allocated costs. This has been attributed to the monopoly position of the DNSP and the fact that the tariffs are individually calculated and are confidential.

The Tribunal is of the view that despite the confidentiality of the CRNP tariffs, the price setting process should be transparent and able to be understood by the customer. This is the basis of good business practice. The Tribunal's determination will further facilitate this as CRNP tariffs will subject to the following provisions:

- **Weighted average price cap.** CRNP prices, will be included, and subject to, the overall weighted average price cap.[233]
- **Pricing principles.** The pricing principles set out in Appendix 12 apply equally to prices for large business customers, and tariff setting for residential and other non-residential customers.
- **Information disclosure and public consultation.** DNSPs are required to disclose their cost allocation methodology in relation to each customer class, in the network strategy statement. Any changes to the pricing methodologies or approach set out in the network strategy statement (including the cost reflective network pricing methodology) will require public consultation with organisations listed on their Register of Interested Parties. Annual price or tariff changes and the impacts on the customer are required to be disclosed in the annual prices report. CRNP customers should be provided with sufficient notification of up-coming changes as part of this process.

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230 Country Energy submission to the 2004 draft determination, 5 March 2004, p 143; Integral Energy submission to the 2004 draft determination, 5 March 2004.

231 Clause 6.18A of the Code suggests that a large customer is one where the load is >10MW or 40GWh per annum.

232 At the public forums to the review and during the Pricing Issues Consultation Group meetings.

233 They will however, not be disclosed publicly and the price limits on network tariffs do not apply to CRNP tariffs.

In addition, although the price setting arrangements in the determination were developed as an alternative pricing methodology to Part E, clause 6.11(e) of the Code, these arrangements do not replace all of the provisions of the Code. In particular, provisions that are applicable to large customers continue to apply in the following areas:

- **Unbundling DUOS and TUOS charges.** Clause 6.18A of part E of the Code recognises that unbundling of TUOS[234] and DUOS charges on customer bills should occur on request for customers who have a load greater than 10MW or 40GWh per annum, or have metering equipment capable of capturing relevant transmission and distribution system usage data. The 'unbundled' information must include the components of each charge and the methodology used for unbundling.
- **Negotiation framework.** Under clause 6.14.7 of the Code each DNSP must establish a negotiating framework in relation to negotiating prices with distribution network users, which is to be approved by the Jurisdictional Regulator (the Tribunal).

  While the Tribunal did not see any reason to change the Code requirements, the Pricing Issues Consultation Group noted that there was a need to facilitate a more transparent and simple approach throughout the industry. The Tribunal therefore encouraged the DNSPs to develop consistent frameworks, and to address the needs of customers who connect embedded generation, wherever possible.

15.3.7 The Tribunal will continue to publish comparative price and service information

The Tribunal intends to continue to provide a public comparative report on the DNSPs' historical performance, including financial, operational, service quality, capital expenditure, and consumption by customer class and average prices for the financial year. The Tribunal will begin compiling the report after the receipt and approval of the Regulatory Accounts on 30 October each year. The Tribunal aims to release this report in February or March of the following year.

234 TUOS charges refers to the 'transmission use of system' component of the network tariff which is known as the 'transmission cost recovery tariff' in the Tribunal's determination.

16 EXCLUDED DISTRIBUTION SERVICES

The Tribunal has defined prescribed distribution services 'by exclusion'. That is, all distribution services provided by the DNSPs are prescribed distribution services except those identified separately as excluded distribution services. The Tribunal has excluded services primarily on the basis of whether they are contestable in NSW. These services will be regulated under the rule – *Regulation of Excluded Distribution Services* – and they will not be subject to the Tribunal's 2004-09 determination.[235]

The Tribunal believes the regulatory framework it has established recognises the varying degrees of competition that can exist in the provision of excluded services. Under the rule, the Tribunal will apply a light-handed form of regulation to all excluded services, based on pricing principles, information disclosure and price monitoring. Public lighting services will be subject to additional information disclosure and price monitoring requirements. However, if the DNSP or another party can demonstrate that there is effective competition in the provision of an excluded service in a specified market, there is provision under the rule[236] for the form of regulation to be waived.

The Tribunal's final decisions on which services are excluded distribution services, and how these services will be regulated are set out below. The rest of the chapter discusses the draft decisions and stakeholder responses to these decisions, and the Tribunal's considerations in making its final decisions.

16.1 Final decisions

The Tribunal has defined prescribed distribution services as all distribution services except for those listed as excluded distribution services in Table 16.1. This list of excluded distribution services is fixed for the regulatory period (however, the form of regulation to be applied to these services may vary).

Table 16.1 List of excluded distribution services

Customer funded connections	Design and construction of new connection assets; design and construction of customer-funded network augmentations
Customer specific services	Services requested by the customer which includes: asset relocation works; conversion to aerial bundled cable; temporary, stand-by, reserve or duplicate supplies, other customer-requested services which are non-standard (however recoverable work undertaken by DNSPs in emergency conditions - 'emergency recoverable works', and separately defined monopoly services, remain as prescribed distribution services)
Metering services for types 1- 4 meters	Including meter supply, installation and maintenance; meter reading, meter tests
Public lighting construction and maintenance	Construction and maintenance of public lighting assets

235 This is as provided for under clause 6.10.5 of the National Electricity Code.

236 IPART, *Regulation of Excluded Distribution Services,* June 2004.

The Tribunal has decided that excluded distribution services will be regulated under the Rule – *Regulation of Excluded Distribution Services*. Unless it can be demonstrated that 'effective' competition exists in the provision of that service in a specified market, then all excluded distribution services will be subject to the following provisions:

- ***Pricing principles***
  - **Prices are to signal the economic costs of service provision by being subsidy free (that is, they should lie between incremental costs and stand alone costs)**
  - **Underlying service classifications, cost data, cost allocations and other elements that contribute to pricing decisions should be periodically reviewed and updated where relevant to reflect industry developments and changes in user requirements and preferences, methods of service provision and costs.**
- ***Information disclosure requirements*. DNSPs are required to provide a description of the excluded distribution service, associated terms and conditions, indicative prices, and rates and services associated with the provision of the excluded distribution service, on its website, and in hard-copy if requested by a customer or the Tribunal.**
- ***Price monitoring arrangements*. The Tribunal will monitor prices of excluded distribution services on a market surveillance basis. If it receives a complaint, it will investigate whether the price satisfies the pricing principles described above and whether the information disclosure requirements described above have been met.**

All provisions will be waived (and no regulation will apply) for services that satisfy the 'competition test'. However, the regulation can be reinstated if the circumstances surrounding the provision of a service change, so that it no longer satisfies the competition test.

Regulation of public lighting services

Public lighting construction and maintenance services will be subject to additional information disclosure and price monitoring provisions:

- **Two months prior to any price changes, the DNSP is required to submit a public lighting report to the Tribunal outlining the proposed price changes; the costs of providing the services; the service standards which support these costs and an assessment of the impact of the changes on customers.**
- **The Tribunal will assess the proposed price changes in light of the pricing principles and whether the DNSP has considered the impacts on customers. If the Tribunal is not satisfied, it will require the DNSP to submit an alternative proposal. If it accepts the proposed price changes, the DNSP must make the price change information and the new prices available to customers one month before the new prices become effective.**

All the excluded distribution provisions will apply from 1 July, except the information disclosure requirements (including the additional requirements in relation to public lighting services), which will apply from 1 October 2004.

These arrangements will not apply to prices subject to individually negotiated contracts.

16.2 Summary of draft decisions on list of excluded services and stakeholder responses

The Tribunal based its decision to exclude a distribution service on whether that service is contestable under the Code of Contestable Works administered by the Department of Energy, Utilities and Sustainability.[237] Being contestable means that service providers other than the DNSPs are able to provide the service. Contestability is the first step towards introducing competition for that service. The extent of the competition that results depends on a number of factors, including the barriers to entry and exit, and the number of service providers entering the market.

Prior to making its draft determination in January 2004, the Tribunal issued a draft decision on the definition of prescribed and excluded distribution services in February 2003. In the February draft decision, the list of excluded services was similar to the list in the final determination, except that metering services for types 5-7 meters and inspection and maintenance of customer installation and private poles were listed excluded.

After considering submissions on its 2003 draft decision on prescribed and excluded distribution services, the Tribunal included a revised list of excluded services in its draft determination released January 2004.[238] The list in the January draft determination was the same as the list included in the final determination, except that inspection of customer installations and private poles are now considered prescribed services and maintenance of customer installations is now regarded as a non-distribution service.

Throughout the review process, stakeholders generally supported the decision to define prescribed distribution services ‘by exclusion’, and to exclude services on the basis of contestability. However, some stakeholders raised concerns about some of the services listed as excluded services, and the decision to fix this list for the regulatory period. In general, stakeholders agreed that customer funded connections and the majority of customer-specific services should be excluded services. However, there was disagreement about how metering services and public lighting should be classified.

16.3 Tribunal’s considerations in making final decisions on list of excluded services

In making its final decisions on which services to include in the list of excluded distribution services, the Tribunal considered all stakeholder responses, as well as the requirements under the Code. Its considerations in relation to each decision are discussed below.

16.3.1 Customer funded connections and customer-specific services are excluded distribution services

The Tribunal decided that customer funded connections and customer-specific services listed on Table 16.1 are excluded services. In making this decision, it took into account that these services are contestable under the Code of Practice of Contestable Works,[239] and the general agreement among stakeholders is that competition exists in the provision of these services in various geographical areas across NSW.

237 Previously known as the Ministry of Energy & Utilities of NSW.

238 IPART, Review of Prescribed and Excluded Distribution Services Draft Decision, February 2003.

239 Determined and administered by the Department of Energy, Utilities and Sustaintabilities.

As part of customer-specific services, in its February 2003 draft decision the Tribunal had classified inspection and maintenance services associated with private poles and customer installations as excluded distribution services. For the final determination, inspection services are now treated as prescribed services and maintenance activities are regarded as non-distribution. This is discussed more fully in section 16.3.5.

16.3.2 Metering services for types 1-4 meters are excluded services, however services for types 5-7 meters are prescribed distribution services

The Tribunal decided that metering services for types 1-4 meters are excluded distribution services, but those for types 5-7 meters are prescribed distribution services.

Types 1-4 meters are mandated for second tier customers with loads greater than 160MWh. Metering services for these meters have been contestable since full retail competition was introduced in 2002, and stakeholders have indicated that there is a relatively robust competitive environment surrounding the provision of these services. [240] The Tribunal therefore considers that they should be regulated as excluded distribution services.

Types 5-7 meters are used by customers with consumption less than 160MWh. The DNSPs are responsible for providing metering services for these meters under a Code derogation,[241] which is due to expire on 30 June 2004. However, the Department of Energy, Utilities and Sustainability (DEUS) is considering whether or not it should apply to have the derogation continue past this date. If the derogation expires, these services will become contestable. In addition, regulators are considering at a national level whether DNSPs should be required to introduce interval meters for customers consuming less than 160MWh, as the result of a draft recommendation from the Joint Jurisdictional Review of Metrology Procedures.[242] Until these questions are resolved, the Tribunal believes it is appropriate that all services associated with metering for type 5-7 meters are regulated as prescribed distribution services.

The Tribunal's decision will not prevent metering services for types 5-7 meters from becoming contestable during the regulatory period. If this occurs, the charges for metering services would need to be made transparent and separated (or 'unbundled') from the existing network charge to enable competition. The Tribunal has included a clause in the determination to this effect. Any such charge would be treated as a new tariff and included within the weighted average price cap, as a prescribed distribution service.

It should be noted, however, that a service does not need to be contestable for the DNSP to levy a separate charge for it. If the DNSP wishes to make the cost of the service transparent, including the cost of installing an interval meter, it may charge separately for it, provided it can demonstrate these costs are not being recovered elsewhere, such as through the general distribution charge.

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240 Country Energy submission to the Draft Determination, 5 March 2004, p 147; Integral Energy submission to the Draft Determination, 5 March 2004, p 71.

241 Clause 9.17A.1(d) of the Code is a derogation which makes the local network provider the responsible person for providing metering services in NSW. It is due to expire on 30 June 2004.

242 The Parer review also recommended the roll-out of interval meters which would be the responsibility of the DNSP.

16.3.3 Construction and maintenance of public lighting are excluded distribution services

The Tribunal decided that construction and maintenance of public lighting assets are excluded distribution services.[243] It based this decision on the fact that these services have been contestable since 1997, under the Code of Practice of Contestable Works. This decision received support from Country Energy.

The Tribunal considered EnergyAustralia's argument that streetlighting is a non-distribution service, and Integral Energy's view that public lighting services should continue to be regulated as prescribed distribution services. However, it believes these services are distribution services, and that they must be excluded on the grounds of contestability.

The Tribunal notes Country Energy's comment that competition for these services has not yet emerged, partly because they have historically been carried out by the DNSPs as part of the distribution function.[244] Similarly the Streetlighting Improvement Program's comment that it is because EnergyAustralia has a "strong monopoly position in the area".[245] This issue is addressed in the regulation of public lighting, outlined in section 16.3.

16.3.4 List of excluded distribution services is fixed for the whole regulatory period

The Tribunal decided to fix the list of excluded distribution services for five years to correspond with the length of the regulatory period for prescribed distribution services. In making this decision, it considered EnergyAustralia's opposition to fixing this list, based on its concern that this would restrict the development of competition for services not included on that list.[246] However, the Tribunal disagrees with this view. It believes the weighted average price cap provides flexibility in the manner in which the DNSP charges for the service. If a prescribed distribution service becomes contestable during the regulatory period, the DNSP should set a separate charge for this service, to provide the appropriate price signals. In most cases, this will require the existing charge to be separated, or 'unbundled', from the existing network charge. The Tribunal has established arrangements under the weighted average price cap to facilitate this.

The Tribunal recognises that if a service is prescribed and contestable, the DNSPs' charges for this service are subject to the weighted average price cap and price limits, while other service providers' charges are not. However, it considers that this is acceptable in the transition period as service providers enter the market.

16.3.5 Non-distribution services

In developing the list of excluded distribution services, the Tribunal considered whether services provided by the DNSPs were non-distribution services. Non-distribution services are not regulated by the Tribunal under the Code, and are not affected by the Tribunal's

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243 There are two other services associated with public lighting that are not excluded services. The first—providing distribution services to deliver energy to the public light—is a prescribed distribution service. The second—providing the energy consumed by the public light—is considered by the Tribunal to be a non-distribution service. As such, it is not affected by the 2004-2009 Determination.

244 Country Energy submission to the draft determination, 5 March 2004, p 153.

245 Streetlighting Improvement Program, *Electricity Distribution Pricing 2004/05-2008/09*, 4 March 2004.

246 EnergyAustralia submission to the draft determination, 5 March 2004.

2004-2009 determination for distribution services. The services that the Tribunal considers as non-distribution are listed on Table 16.2.[247]

Table 16.2 Non-distribution services

Service
Provision of energy for public lighting
Purchase of electricity from photovoltaic cells or embedded generators (note that charges to these customers for use of the distribution system to transport the electricity are distribution services)
Generation, transmission or retail services
Services provided outside the DNSPs responsible distribution area
Maintenance of electrical installations and private power lines
Pole and duct rental

In its draft determination released in January 2004, the Tribunal included the maintenance of customer installations and private poles on the list of excluded distribution services. However, it is now of the view that it is appropriate that these services be considered non-distribution services.

Electrical installations[248] refers to the equipment and wiring on or near a customer's premises, which connect it to the distribution system. Private poles are electricity poles that are located on a customer's premises, and are used to convey electricity to the customer's residence, or are for use on their premises. These assets are owned by the customer, and under the Electricity Supply Act, the owner is responsible for any maintenance works required on these assets. This work is usually performed by electrical contractors, although could be performed by the DNSPs.

As these assets are not a part of the distribution system, and the DNSPs do not have any obligations to maintain them, the Tribunal considers that any maintenance services they do provide are non-distribution activities. Therefore, if the DNSPs do provide such services, they must levy a separate charge, which will not be regulated under the determination or rule for excluded distribution services. [249]

It is noted that the DNSPs do have an obligation to inspect these assets and works under the Electricity Supply (Safety and Network Management) Regulation 2002,[250] to ensure the safety of the surrounding network. The Tribunal considers that inspection services are part of the DNSPs' core functions, and has therefore classified it as a prescribed distribution service. This decision is consistent with recent proposed amendments to the Consumer Safety Act to

247 This list is not exhaustive and provides an indication of the types of the services the Tribunal considered.

248 Also known as 'customer installations'. This point is defined in the Consumer (Safety) Act.

249 Note that in the draft determination the Tribunal had classified these services as excluded on the basis of the ownership of the asset, rather than the service being performed.

250 The Electrical Supply (Safety and Network Management) Regulation 2002 requires network operators to implement a customer installation safety plan which includes an inspection regime and takes into account the Code of Practice – Installation Safety Management. These are different from inspections of work undertaken by accredited service providers, which is separately charged for as a monopoly fee.

clarify the point of responsibility of the owner/occupier. The intention of the clarification[251] is to confirm that these shared structures form part of the electrical installation, except where otherwise agreed between the DNSP and the consumer.

16.4 Summary of draft rule on regulation of excluded distribution services and stakeholder responses

The Tribunal's final decision has affirmed the framework for regulating excluded distribution services outlined in the draft report released in January 2004. In general, stakeholders supported this framework, although some raised concerns with particular aspects of it:

- Several DNSPs argued that the regulation was not 'light-handed' enough for services that are already contestable. It suggested that requirements to publish prices and terms and conditions are unnecessary in a competitive market, particularly where prices may be negotiated with customers based on their individual circumstances.[252]
- In relation to the additional provisions for public streetlighting services:
  - The Streetlighting Improvement Program supported these provisions, commenting that they "…should help reduce the significant information gap regarding the cost of public lighting services, and lead to more appropriate pricing outcomes". However, it requested that the councils, as customers, should have some input regarding prospective changes in prices and costs provided to the Tribunal.[253]
  - Country Energy argued the provisions are not justified, and that the disclosure of the costs of service provision is anti-competitive. However, it acknowledged that some form of lighted handed regulation and compliance assessment may be required while the market is still developing.[254]
  - EnergyAustralia argued that the regulation of public streetlighting is not light handed enough, and does not give DNSPs the flexibility to meet variations in customers' requirements. It proposed a regime that allows for direct negotiation with local councils.[255]

The DNSPs also noted that there will not be enough time for them to apply to the Tribunal to have the regulation of excluded distribution services waived on the grounds that effective competition exists prior to this regulation coming into effect. They also requested that the Tribunal clarify the pricing principles and disclosure of information, particularly for public lighting.

However, second tier retailers commented that the pricing principles will ensure that competition is not stifled. They also argued that if the regulation of an excluded distribution service can be waived on the grounds that effective competition exists, there should be a provision to have the regulation reinstated if circumstance change so that effective competition no longer exists (for example, if a major competitor exits the market).

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251 As suggested by the explanatory notes to the Electricity (Consumer Safety) Bill 2003.
252 Integral Energy submission to the draft determination, 5 March 2004, p 73.
253 Streetlighting Improvement Program, *Electricity Distribution Pricing 2004/05-2008/09*, 4 March 2004.
254 Country Energy submission to the draft determination, 5 March 2004, p 153.
255 EnergyAustralia submission to the draft determination, 5 March 2004, p 78.

16.5 Tribunal's considerations in making its final decisions on the regulation of excluded distribution services

The Tribunal decided that all excluded distribution services will be regulated through the Rule – *Regulation of Excluded Distribution Services*. This rule comprises a 'regulatory package' of pricing principles, information disclosure requirements and price monitoring arrangements, with additional requirements for public lighting. There is provision for this regulation to be removed if effective competition can be demonstrated in the service.

This regulatory framework is not intended to promote or improve competition in these markets—rather it is intended to protect customers in markets where competition is not fully developed. However, the Tribunal has aimed to balance this protection role with the need to allow competition to develop or improve.

The Tribunal also took into account that although all the services are contestable, there are various degrees of competition in each market, and believes that its framework provides for these different situations. It recognises that those markets that have effective competition should not be subject to unnecessary regulation. For this reason, the regulatory framework provides for the regulation to be waived where it can be demonstrated to the Tribunal that an excluded service satisfies the 'competition test' outlined in section 16.5.7.[256]

The Tribunal also does not intend to regulate prices that are part of individually negotiated contracts. These are usually decided between the customer and the DNSP based on non-standard services or other individual provisions. Such arrangements or contracts will sit outside of the Tribunal's excluded distribution service regulation.

16.5.1 Pricing principles

The Tribunal has adapted two principles from the *1999 Pricing Principles and Methodologies*, which were developed by industry participants to apply to the pricing of prescribed distribution services.[257] It believes these principles are valid whether the service is provided in a regulated or unregulated market. Second tier retailers noted that the pricing principles will ensure that competition is not stifled.[258]

The principles are intended to ensure that the services are being charged on a cost-reflective basis and reflect current industry practices and costs. The first principle provides an upper and lower bound for the pricing of services. Where prices reflect the economic costs of service provision they make an important contribution to economic efficiency and welfare.[259]

The second principle reflects the fact that changes in areas such as metering technology, retail competition, alternative forms of service provision, and user preferences can lead to shifts in the nature of efficient network prices. For prices to remain efficient they should reflect such developments. The Tribunal has added this principle since the draft

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256 The 'regulatory package' can be reinstated at a later date, if market circumstances change.

257 These principles will continue to apply to prescribed distribution services under the determination.

258 Origin Energy submission to the draft determination, 5 March 2004, p 7; AGL Sales and Marketing, submission to the draft determination, 5 March 2004.

259 In the draft rule, the Tribunal had based the principle on the notion of 'true economic cost', however, this has been amended to reflect the concept of subsidy free prices, a term that is better understood within the industry.

determination in order to provide further clarity as to what should be considered when setting prices.

16.5.2 Information disclosure requirements

The Tribunal decided to set minimum requirements for information disclosure. It recognises that as these services are available in the contestable market, full information disclosure may disadvantage the incumbent service provider, and would require a more rigorous monitoring regime. However, the Tribunal has taken the approach that some information disclosure is appropriate, to enable customers and stakeholders to compare DNSPs' prices and understand the basis of the charge. In a competitive market, such information would be freely available, as companies come under pressure to compare their performance and make improvements where possible.

It noted Integral Energy's view that requirements to publish prices and terms and conditions are unnecessary in a competitive market, particularly where prices may be negotiated with customers based on their individual circumstances.[260] However, the Tribunal does not intend the DNSPs to disclose commercially sensitive prices that apply to individual customers. The requirements aim to ensure that the DNSPs disclose enough information for customers to understand the basis of the price being charged. If this price is not a standard price, the DNSP should disclose its methodology and considerations in setting or negotiating a price. If part of the charge depends on the cost of materials, the DNSP should provide examples of these costs, or have a list of the costs of such materials available for viewing on request.

16.5.3 Price monitoring

The Tribunal decided to undertake price monitoring on a market surveillance basis only (that is, when a complaint is received). The Tribunal had originally considered requiring DNSPs to submit information on prices for excluded services annually for it to assess.[261] However, it was concerned that restricting the DNSPs to annual prices changes would put them at a disadvantage in a competitive market. Furthermore, given that most of the excluded distribution services are contestable, it considered it prudent to relax the price monitoring provisions for all excluded services except for construction and maintenance of public lighting (see section 16.5.4).

16.5.4 Additional requirements for public lighting services

The Tribunal decided to include additional information disclosure requirements and price monitoring provisions in relation to public lighting services, because there is little competition in the provision of these services, and there are outstanding customer service issues that need to be resolved. In making this decision, it took into account the views of stakeholders that this is because these activities were treated as a prescribed distribution service under the 1999 determination and have historically been carried out by DNSPs as part of the distribution function,[262] hence they have a strong monopoly position in the area.[263]

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260 Integral Energy submission to the draft determination, 5 March 2004, p 73.

261 This was proposed in IPART's Draft Decision, Review of Prescribed and Excluded Distribution Services released in February 2003.

262 Country Energy submission to the draft determination, 5 March 2004, p 153.

263 Streetlighting Improvement Program, *Electricity Distribution Pricing 2004/05-2008/09*, 4 March 2004.

The regulation of public lighting under the *Rule – Regulation of Excluded Distribution Services*, requires the DNSPs to provide a pricing proposal to the Tribunal two months prior to any new prices coming into effect, and to publish prices and their justification, one month prior to their coming into effect. The DNSPs will have to justify changes in public lighting charges in light of the pricing principles, and must consider the impact on customers.

The regulatory criteria proposed, received support by the Streetlighting Improvement Program, and the Local Government Association of NSW in conjunction with the Shires Association of NSW.[264] Their submissions highlighted the need for greater access to information regarding the cost of public lighting services, transitional protection against unexpected price shocks and for local councils to be able to provide input into the proposals for price variations.[265]

Country Energy expressed its concern that the disclosure of the costs of service provision is anti-competitive.[266] However, the Tribunal is of the view that the regulation of public lighting will provide for the right balance between protection for customers and the development of a competitive market.

EnergyAustralia proposed a regime that allows for direct negotiation with local councils. It believes that the Tribunal's regulation is not light handed and does not have the flexibility to meet variations in customers' requirements.[267] As noted in section 16.5, the Tribunal does not intend to regulate prices that are part of individually negotiated contracts. It encourages the development of such agreements or contracts, particularly for the provision of public lighting services, as negotiated prices can be tailored to the customers' specific needs and can better meet their requirements.

The Tribunal considered the Streetlighting Improvement Program's suggestion that councils, as customers, should have some input to its assessment of the DNSPs' proposed changes to prices and costs. However, the Tribunal is of the opinion this would be a more heavy-handed approach. Nevertheless, where the proposed changes will have a significant impact on customers, the Tribunal believes seeking public comment may be appropriate. It has therefore made provision for this in the rule.

The Tribunal notes that there are considerable historical issues related to the ownership and service quality of public lighting assets which was raised in submissions to its draft rule.[268] It is pleased to note that the Department of Energy, Utilities and Sustainability has established a working group on public lighting. It supports the development of outcomes that will facilitate the provision of this service in a competitive market, including minimum standards of service.

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264 Streetlighting Improvement Program, *Distribution Pricing 2004/05-2008/09*, 4 March 2004.

265 Local Government Association of NSW and Shires Association of NSW submission to the draft determination, 4 March 2004.

266 Country Energy submission to the draft determination, 5 March 2004, p 153.

267 EnergyAustralia submission to the draft determination, 5 March 2004, p 78.

268 Integral Energy submission to the draft determination, 5 March 2004, p 69; Country Energy submission to the draft determination, 5 March 2004, p 153; Streetlighting Improvement Program, *Electricity Distribution Pricing 2004/05-2008/09*, 4 March 2004.

16.5.6 Information provision conditions to commence 1 October 2004

The Tribunal considered DNSPs concerns that there will not be sufficient time for them to apply to have the regulation of excluded distribution services waived on the grounds that effective competition exists prior to this regulation coming into effect. The DNSPs also requested the Tribunal to provide further clarity regarding the pricing principles and disclosure of information, particularly for public lighting. In response to these concerns, it decided to defer the commencement date of all information disclosure requirements, including the additional requirements for public lighting services, until 1 October 2004. All other provisions in the rule will apply from 1 July.

As a result of this, as DNSPs are required to submit information to the Tribunal two months prior to any proposed price changes for the construction and maintenance of public lighting, the earliest date on which such a price change can occur is 1 October 2004. However, this is not the case for the other excluded distribution services.

16.5.7 No regulation will apply where the competition test is satisfied

The Tribunal decided that if it can be demonstrated that effective competition exists in the provision of an excluded distribution service in a specified market, the regulatory package outlined above, will be waived (except for public lighting services).

It considers that 'effective' competition exists where no company has enough market power to allow it to increase prices, reduce service quality and restrict services and still maintain profitability. A company that attempts such actions in the face of competition would be expected to lose customers and face lower profits. Effective competition includes the situation where a DNSP has a significant share (or all) of the market, but where the threat of competition places sufficient competitive pressure on it to prevent it from exercising its market power to the detriment of consumers (that is, 'potentially competitive' markets).[269]

If a DNSP (or other party) wishes to have the regulation of an excluded distribution service waived, it will need to apply to the Tribunal, providing information to demonstrate that the service meets the competition test set out in the Rule—*Regulation of Excluded Distribution Services*. The Tribunal will then assess the effectiveness of competition on the basis of the information.

The criteria for the competition test includes:

- the structural features of the market, such as:
  - the definition of the market for the service, which should encompass all services that are in close competition with that service
  - the number of firms competing in that market and the degree of market concentration
  - the barriers to entering and exiting the market. Low barriers will facilitate entry to the market and ensure that competitive pressures are brought to bear on the DNSP and other entrants
- the conduct of firms in the market, including:

[269] This is to be distinguished from the use of the term 'potential for competition' in the February Draft Decision which referred to a service which is not contestable under the Code of Contestable Works, however has the potential to become contestable in the future.

- supplier behaviour. Effectively competitive markets may be characterised by actual entry and exit of firms and innovation in service delivery.
- customer outcomes. The customer is the ultimate beneficiary of effective competition in the market. The Tribunal will need to see evidence that the customers are benefiting from competition in the market.

The structural criteria examine the pre-conditions for effective competition, and are largely a standard component of similar tests applied in other jurisdictions. The conduct criteria focus on the effectiveness of competition. The Tribunal considers that the addition of these criteria to the standard test will improve the information base for decision making.

16.5.8 Regulation can be reinstated if circumstances change

The Tribunal decided that where the regulation of an excluded distribution service has been waived on the grounds that effective competition exists, this regulation can be reinstated if the circumstances surrounding the provision of that service change. A DNSP or other party will need to apply to have the regulation reinstated. This application will need to demonstrate that the service no longer satisfies the competition test outlined in 16.5.5 above. The Tribunal will then reapply the competition test.

In making this decision, the Tribunal considered the comments of stakeholders[270] on this issue. It is satisfied that such a provision is necessary to protect customers in the event of an unanticipated change in the market for the provision of a service, for example, if a major accredited service provider withdraws.

270 Origin Energy submission to *Review of Prescribed and Excluded Distribution Services,* 22 April 2003; AGL Energy Sales & Marketing submission to *Review of Prescribed and Excluded Distribution Services*, April 2003.

APPENDIX 1 LIST OF SUBMISSIONS RECEIVED AND PUBLIC FORUMS HELD DURING THE 2004 REVIEW

Table A1.1 2004 Electricity Network Review Issues Paper – 26 November 2002

Australian Inland
Country Energy
EnergyAustralia
Integral Energy
AGL Energy Sales & Marketing
AGL Retail Energy Limited
Australian Consumers' Association
Australian Council for Infrastructure Development Limited
Australian Environment Business Network (AEBN)
Combined Pensioners & Superannuants Assoc. Orange Branch
Connect Engineering Pty Ltd
Country Energy Rural Advisory Group
Energy Markets Reform Forum
Energy Users Association of Australia
Environment Protection Authority
Foldraft Pty Ltd
National Electrical Contractor's Association
Origin Energy Retail
Peak Environment Groups of NSW
Public Interest Advocacy Centre
South East Power Lines & Electrical Services
Street Lighting Improvement Program
Tenants' Union of NSW
West Wallsend Combined Pensioners Assoc

Table A1.2 2004 Draft Decision on Prescribed and Excluded Distribution Services 7 February 2003

AGL Retail Energy Limited
Australian Inland
Country Energy
EnergyAustralia
Integral Energy
National Electrical Contractor's Association
Next Energy (on behalf of the South Sydney Region of Councils)
Origin Energy

Table A1.3 Providing Incentives for Service Quality in NSW Electricity Distribution 16 May 2003

AGL Retail Energy Limited
Australian Inland
Country Energy
Energy Markets Reform Forum
EnergyAustralia
Integral Energy
Ministry of Energy and Utilities
Origin Energy Retail
Public Interest Advocacy Centre

Table A1.4 Total Cost Review - Meritec Draft Report 7 July 2003

Australian Inland
Country Energy
Energy Markets Reform Forum
Integral Energy
Total Environment Centre

Table A1.5 Determining Sales Volumes for 2004 Electricity Network Review 17 July 2003

Agility
AGL Energy Sales & Marketing
Country Energy
EnergyAustralia
TransGrid
TXU Electricity Limited

Table A1.6 Supplementary Submissions to 2004 Review and comments on Secretariat's Preliminary Analysis Discussion Paper – 16 September 2003

AGL Energy Sales & Marketing
Australian Inland
Country Energy
Energy and Water Ombudsman NSW
Energy Markets Reform Forum
Energy Users Association of Australia
EnergyAustralia
Environment Protection Authority
Integral Energy
Origin Energy Retail
Public Interest Advocacy Centre
Street Lighting Improvement Program
Total Environment Centre
TransGrid

Table A1.7 NSW Electricity Distribution Pricing 2004/05 to 2008/09 - Draft Report 9 January 2004

Agility
AGL Energy Sales & Marketing
Australian Inland
Bayard Capital
BES (Aust) Pty Ltd
Country Energy
Dept of Education and Training
Energy and Water Ombudsman NSW
Energy Markets Reform Forum
Energy Networks Association
Energy Users Association of Australia
EnergyAustralia
Integral Energy
LGA & LGSA of NSW
NSW Treasury
Origin Energy Retail
Public Interest Advocacy Centre
Street Lighting Improvement Program
Total Environment Centre
TXU Electricity Limited

Public Forums

21 February 2002	Forum on form of regulation
11 April 2003	DNSP presentations of their submissions to the 2004-2009 Review
11 July 2003	Public workshop on Meritec's Total Cost Review Draft Report
17 July 2003	Non-DNSP presentations of their submissions to the 2004-2009 Review
29 July 2003	Public workshop on providing incentives for service quality
18 March 2004	Public workshop on Draft Determination
Various	Pricing Issues Consultation Group meetings

APPENDIX 2 CODE REQUIREMENTS

Code requirement	Reference in 2004-09 Report
The principles for determining prescribed and excluded services 6.10.4(a)	Chapters 3 and 16
That the form of regulation for excluded distribution services be light landed 6.10.4(b)	Chapter 16
Economic regulation either prospective CPI-X or an incentive based variant 6.10.5(a)	Chapter 3
Specification of the form of economic regulation 6.10.5(b)	Chapter 3
Length of the regulatory period 6.10.5(c)	Chapter 3
Demand growth which the distribution network owner is expected to service over the regulatory period 6.10.5(d)(1)	Chapter 4 and Appendix 4
The service standards applicable over the regulatory period 6.10.5(d)(2)	Chapter 10
Price stability over the regulatory period 6.10.5(d)(3)	Chapter 7 and Chapter 13
Judgement of the potential efficiency gains to be realised in expected operating, maintenance and capital costs 6.10.5(d)(4)	Chapter 4
The weighted average cost of capital 6.10.5(d)(5)	Chapter 6 and Appendix 7
Provision of a fair and reasonable risk adjusted cash flow rate of return on efficient investment 6.10.5(d)(6)	Chapters 5, 6 and 7 Appendix 8
Recovery of reasonable costs arising out of but not limited to taxes, transmission and avoided transmission costs 6.10.5(d)(7)	Chapters 13
Correction factor from the previous regulatory period 6.10.5(d)(8)	Chapters 3, 6 and 13
Any changes in energy losses in the distribution network 6.10.5(d)(9)	Chapter 8
The on-going commercial viability of the distribution network 6.10.5(d)(10)	Chapter 6 and 7 and Appendices 11 to 14
Other relevant financial indicators 6.10.5(d)(11)	Chapter 7 and Appendices 11 to 14
Application of an alternative pricing methodology to the approach set in Part E of chapter 6 6.11(e)	Chapter 15

APPENDIX 3 CLAUSES FROM THE NATIONAL ELECTRICITY CODE

6.1.1 Summary of key principles and core objectives of network pricing

(a) Without limiting the application of any other provision of this *Code*, this clause 6.1.1 summarises the key principles and core objectives which are intended to apply to the *network* pricing arrangements in this Chapter 6.

(b) The key principles underlying the *transmission* and *distribution* pricing provisions in this Chapter 6 are intended to:

(1) promote competition in the provision of *network services* wherever practicable;

(2) facilitate a commercial environment which is transparent and stable, and which does not discriminate between users of *network services*; and

(3) regulate the non-competitive market for *network services* in a way which seeks the same outcomes as those achieved in competitive markets.

(c) The core objectives intended to be achieved by the application of the *transmission* and *distribution* pricing provisions in this Chapter 6 are:

(1) efficiency in the use, operation, and maintenance of, and investment in, the *network*, and in the location of *generation* and demand;

(2) upstream and downstream competition;

(3) price stability; and

(4) equity.

6.10.2 Objectives of the distribution service pricing regulatory regime to be administered by the Jurisdictional Regulators

The *distribution service* pricing regulatory regime to be administered under Part D of the *Code* must seek to achieve the following outcomes:

(a) an efficient and cost-effective regulatory environment;

(b) an incentive-based regulatory regime which:

(1) provides an equitable allocation between *Distribution Network Users* and *Distribution Network Owners* of efficiency gains reasonably expected by the *Jurisdictional Regulators* to be achievable by the *Distribution Network Owners*;

(2) provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to *Distribution Network Owners* on efficient investment, given efficient operating and maintenance practices of the *Distribution Network Owners*;

(3) ensures consistency in the application of regulations applicable to:

(i) *connection* to *distribution networks*;

(ii) *distribution service* pricing; and

(4) provides for the recovery by *Distribution Network Service Providers* of *Customer TUOS usage charges* from those *Distribution Customers* that have a *metering installation* capable of capturing relevant *transmission system* and *distribution system* usage data, in a way that preserves the location and time signals of the *Customer TUOS usage prices*;

(c) prevention of monopoly rent extraction by *Network Owners*;

(d) an environment which fosters an efficient level of investment within the *distribution* sector, and upstream and downstream of the *distribution* sector;

(e) an environment which fosters efficient operating and maintenance practices within the *distribution* sector;

(f) an environment which fosters efficient use of existing infrastructure;

(g) reasonable recognition of pre-existing policies of governments which are *Distribution Network Owners* regarding *distribution* asset values, revenue paths and prices;

(h) promotion of competition in upstream and downstream markets and promotion of competition in the provision of *network services* where economically feasible;

(i) reasonable regulatory accountability through transparency and public disclosure of regulatory processes and the basis of regulatory decisions;

(j) reasonable certainty and consistency over time of the outcomes of regulatory processes, recognising the adaptive capacities of *Code Participants* in the provision and use of *distribution network* assets;

(k) reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of *Distribution Network Owners, Distribution Network Users* and the public interest.

6.10.3 Principles for regulation of distribution service pricing

The regime under which the revenues of *Distribution Network Owners* and *Distribution Network Service Providers* (as appropriate) are to be regulated is to be administered by the *Jurisdictional Regulators* in accordance with the following principles:

(a) Concerns over monopoly pricing in respect of the *distribution network* will, wherever economically efficient and practicable, be addressed through the introduction of competition in the provision of *distribution services*.

(b) Where pro-competitive and structural reforms alone are not a practicable or adequate means of addressing the problems of monopoly pricing in respect of *distribution services* or protecting the interests of *Distribution Network Users,* the form of economic regulation to be applied is described in clause 6.10.5.

(c) The form of economic regulation applied by the *Jurisdictional Regulators* must not be changed during a *regulatory control period*.

(d) Subject to clause 6.10.3(c), if a *Jurisdictional Regulator* proposes to amend the form of economic regulation specified in clause 6.10.5 applied to a *Distribution Network Owner,* the *Jurisdictional Regulator* must:

   (1) give two years prior notice to the *Distribution Network Owner* of the new economic regulation arrangements to apply from the commencement of the next *regulatory control period*; and

   (2) publish a description of the process and timetable for re-setting the form of economic regulation at a time which provides all affected parties with adequate notice to prepare for, participate in, and respond to that process, prior to the commencement of the *regulatory control period* to which that form of economic regulation is to apply.

(e) The regulatory regime to be administered by the *Jurisdictional Regulator* must be consistent with the objectives outlined in clause 6.10.2 and must also have regard to the need to:

   (1) provide *Distribution Network Owners* with incentives and reasonable opportunities to increase efficiency;

   (2) create an environment in which *generation*, energy storage, demand side options and *network augmentation* options are given due and reasonable consideration;

   (3) take account of and be consistent with the allocation of risk between *Network Owners* and *Network Users*;

   (4) take account of and be consistent with any obligations of *Code Participants* in relation to *distribution networks* under Chapter 5;

(5) provide a fair and reasonable risk-adjusted cash flow rate of return to *Distribution Network Owners* on efficient investment given efficient operating and maintenance practices on the part of the *Distribution Network Owners* where:

(i) assets created at any *time* under a *take or pay contract* are valued in a manner consistent with the provisions of that contract;

(ii) subject to clause 6.10.3(e)(5)(i), assets (also known as "sunk assets") in existence and generally in service on 1 July 1999 are valued at a value determined by the *Jurisdictional Regulator* or consistent with the regulatory asset base established in the *participating jurisdiction*;

(iii) subject to clause 6.10.3(e)(5)(i), 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 *Jurisdictional Regulator*. In determining the basis of asset valuation to be used, the *Jurisdictional Regulator* 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 relevant decisions of the Council of Australian Governments; and

(C) such other matters reasonably required to ensure consistency with the objectives specified in clause 6.10.2; and

(iv) benchmark returns to be established by the *Jurisdictional Regulator* are to be consistent with the method of valuation of new assets and revaluation, if any, of existing assets and consistent with achievement of a commercial economic return on efficient investment;

(6) provide reasonable certainty and consistency over time of the outcomes of regulatory processes having regard for:

(i) the need to balance the interests of *Network Users* and *Network Owners*;

(ii) the capital intensive nature of the *distribution* sector, the relatively long lives of *distribution* assets, and the variable and frequent *augmentation* of the *distribution network*;

(iii) the need to minimise the economic cost of regulatory actions and uncertainty;

(iv) relevant previous regulatory decisions made by authorised persons including:

(A) the initial revenue setting and asset valuation decisions made by a government at a time at which that government was a *Distribution Network Owner* in the context of industry reform pursuant to the Competition Principles Agreement;

(B) decisions made by *Jurisdictional Regulators* and any regulatory intentions previously expressed; and

(C) decisions made by ministers under jurisdictional legislation.

APPENDIX 4 THE ELECTRICITY INDUSTRY IN NSW

A4.1 Structure of electricity industry

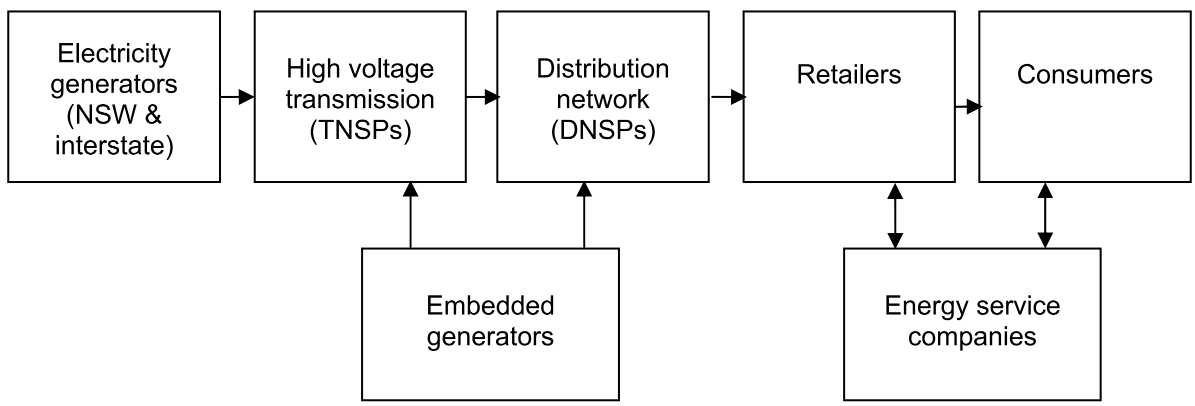
Australia's electricity industry has undergone significant structural change over the past 10 years, including disaggregation of generators, transmission, distribution and retailing; the full privatisation of the Victorian market and major privatisation in South Australia; and the introduction of full retail contestability in the NSW, Victorian, South Australian and Australian Capital Territory markets.

The NSW electricity industry comprises the following bodies (Figure 4.1):

- *generators, including embedded generators,* who generate electricity and sell it to retailers through the wholesale market and are connected to either the transmission or distribution networks
- *transmission network service providers*[271] (TNSPs) who convey electricity along the high voltage network
- *distribution network service providers* (DNSP) who convey electricity from the transmission systems to end-users via a lower-voltage network
- *retailers* who buy electricity from generators in the wholesale market and sell electricity to consumers
- *energy service companies* who provide energy management services possibly in partnership with retailers, to reduce energy costs for end-users.

Figure A4.1 shows how these bodies interact with each and with consumers.

Figure A4.1 NSW electricity industry structure



The introduction of the National Electricity Code and subsequent national electricity market has meant that generators and retailers now participate in the wholesale market administrated by the National Electricity Market Management Company Limited. Most customers in NSW purchase electricity from a retail electricity company.

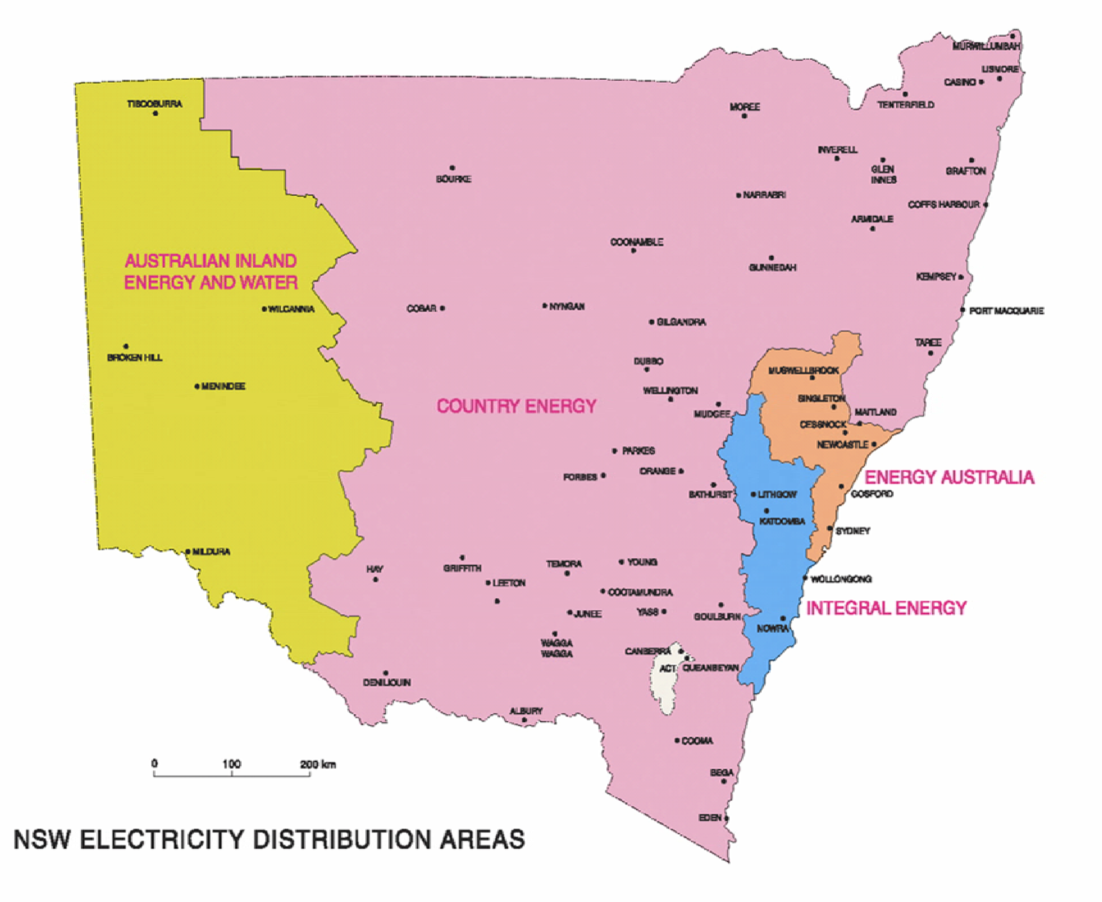
271 The Australian Competition and Consumer Commission (ACCC) regulates transmission revenues and prices are established in accordance with the National Electricity Code.

The TNSPs (TransGrid, EnergyAustralia and interstate suppliers such as Powerlink) transport electricity from the generators to a number of points in each DNSP's area and charge the DNSPs the cost of transmission. The DNSPs (EnergyAustralia, Integral Energy, Country Energy and Australian Inland) then distribute the electricity to retail customers and charge the retail company. The electricity retailers bill consumers an amount of money for using each individual service. Energy service companies may provide energy management services in partnership with retailers to reduce energy costs for end-users.

A4.2 DNSPs' areas of operations

The NSW DNSPs' areas of operation vary widely (see Figure A4.2). EnergyAustralia and Integral Energy operate predominantly in densely populated urban districts, with a larger number of customers over relatively small geographic areas. Australian Inland and Country Energy operate in sparsely populated rural regions, over much larger geographical area.

Figure A4.2 Operating areas of NSW DNSPs



Source: Ministry of Energy and Utilities, *2001/02 NSW Electricity Network Performance Report,* June 2003.

A4.3 Operating statistics

The differences in these areas of operations result in diverse operating statistics across the DNSPs (Table A4.1).

Table A4.1 DNSP operating statistics for 2002/03

	EnergyAustralia	Integral Energy	Country Energy	Australian Inland
Total service area (sq km)[3]	22,275	24,500	582,000	155,000
Total system length (km)[2]	47,144	33,863	182,023	9,425
Per cent of total system length underground (%)	24	27	2	0.4
Maximum demand (MW)[1]	5,080	3,114	2,021	60
Energy sold (GWh)[1]	25,077	16,486	10,387	260
Annual load factor (%)[2]	61	64	57	61
Total customers[1]				
Residential	1,285,596	716,280	566,165	15,534
Non-residential	144,658	71,380	145,999	5,940

Source:
1. DNSPs submission to the 2004 review and DNSPs Price and Service Reports
2. Meritec, *Review of Capital and Operating Expenditure of the NSW DNSPs*, Final Report, September 2003, p 16.
3. DNSPs *Price and Service Report*, 2002.

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APPENDIX 5 TARIFF REFORM AND THE WEIGHTED AVERAGE PRICE CAP AND PRICE LIMITS FORMULA

The weighted average price cap control formula, and price limit formula, is calculated using historical audited quantities of consumption. When tariff reform occurs, the historical quantities do not reflect these changes for two years until actual data are available to be used. This will occur in the following circumstances:

- the introduction of new tariffs
- the introduction of new tariff components for existing tariffs (for example, introducing a step rate for the usage component of the domestic tariff)
- changing the structure of existing tariffs or tariff components (this is essentially introducing a new tariff component, for example, changing the threshold on an inclining block tariff or the time bands associated with time of use tariffs)
- when customers move between existing tariffs (from 'origin' tariffs to 'replacement' tariffs).

This appendix sets out the adjustment process for incorporating such tariff reform changes in the weighted average price cap formula when setting prices for Year *t+1,* and for calculating the price limit for affected tariffs. It provides for *estimates* for the historical quantity weights q_{ij}^{t-1}, and a substitute value for p_{ij}^{t} to be used when calculating compliance with the weighted average price cap formula, and for calculating the price limits.

A5.1 Value of q_{ij}^{t-1} when new tariffs, or new tariff components are introduced

When a new tariff or a new tariff component is introduced,[272] there are no historical quantities available. In order to incorporate these tariff proposals in the weighted average price cap and calculate a price limit, the Tribunal requires 'reasonable estimates' to be submitted by the DNSP, based on the quantities that would have been sold, if the new tariff (or new component) had been introduced in Year (*t-1*). The Tribunal has developed the following process in order for the DNSP to arrive at these estimates.

Firstly, the DNSP must nominate a corresponding 'origin network tariff/s' or 'origin network tariff component', which represents the tariff/s or components that the customers who will be moved to the new tariff, are currently on, or currently being charged at. The DNSP must provide 'reasonable estimates' for q_{ij}^{t-1} for all applicable units of measure (kWh, kW) for both the new tariff components and the 'origin network tariff/s components'.

272 This includes when an existing tariff component has undergone a structural change such that the new structure is essentially a 'new' tariff component eg. changing the threshold value for a step rate, or time bands on a time of use tariff.

Secondly, the DNSP must make the following assumptions when calculating the 'reasonable estimates'*:*

1. The only customers that would have moved to the new tariff/component in (*t-1*) were as a result of the direction of the DNSP due to tariff reform (as permitted under the customer's standard network connection contract).[273] This means that no new customers are included in the estimate,[274] nor customers that request to change tariffs either voluntarily, or do so through the actions of the retailer.

2. Customers have the same consumption and load profile on the new tariff/ component as they did on the 'origin network tariff'. This implies that the sum of the 'reasonable' estimates for Year *t-1* for each unit of measure on the new tariff plus the 'reasonable' estimates for Year *t-1* for each unit of measure on the 'origin network tariff', equals the actual audited quantities that occurred for the 'origin network tariff' in Year *t-1*.

In the year after a new tariff or new tariff component has been introduced (Year *t)*, there is still not a full year of actual historical data available to be used for q_{ij}^{t-1}, hence the DNSP will be required to submit reasonable estimates for both the new tariff and the corresponding origin network tariffs. The DNSP may base the reasonable estimates on the actual quantities that have occurred to date on the new tariff and origin network tariff. The DNSP must demonstrate how it has arrived at the estimates.

A5.2 Value of p_{ij}^t when new tariffs or new tariff components are introduced

The p_{ij}^t prices of the corresponding 'origin network tariff' components will be used as the p_{ij}^t prices for the new tariff components (or the r_j^t in the price limits formula). A corresponding 'origin network tariff' component may be any component that is measured in the same units of measure as the new tariff component. If there is no corresponding component with the same units of measure, p_{ij}^t will be taken as zero.

273 Each customer has a standard network connection contract with its DNSP and a separate contract with its respective retailer who manages the relationship with the DNSP on the customer's behalf.

274 New customers have been allowed for in the growth assumption used when setting the X-factor.

Table A5.1 Example - Introducing a Step Rate or Inclining Block tariff component

Tariff Reform		p_{ij}^{t}	p_{ij}^{t+1}	q_{ij}^{t-1}
Existing tariff – standard domestic				
Fixed charge	$ pa per customer	$30	n/a	25,000 customers
Variable rate (all consumption)	c/kWh	0.04	n/a	200,000 MWh
Proposed tariff with new component				
Fixed charge	$ pa per customer	$30	$25	25,000 customers
Variable rate 1 (consumption up to 5000kWh per customer)	c/kWh	0.04 (above)	0.02	150,000MWh
Variable rate 2 (consumption over 5000kWh per customer)	c/kWh	0.04 (above)	0.05	(200,000 – 150,000) = 50,000MWh

n/a: not applicable.

A5.3 Value of q_{ij}^{t-1} when customers are transferred by the DNSP to an alternative tariff

If the DNSP proposes to move a number of customers across to an alternative existing tariff,[275] the rate at which revenue will accrue is different to what was used to calculated the X factor and will be different to what will be calculated under the weighted average price cap. In addition, the price limit calculation will not reflect the actual increase to the customers being transferred. In these circumstances, the Tribunal will require the DNSP to submit 'reasonable estimates' for q_{ij}^{t-1} for the tariff that the customer is currently on (the 'origin' tariff), and the tariff that the DNSP will move the customers to (the 'replacement' tariff), taking the transfer into account.

For compliance purposes, the assumptions the DNSP must make when calculating the 'reasonable estimates' are:

1. The customer movement occurred in (*t-1*).
2. The only customers that moved were as a result of the direction of the DNSP due to tariff reform (as permitted under the standard network connection contract).[276] The estimates are not to include customers that may move at their discretion or due to the retailer discretion (voluntary movement).
3. Customers have the same consumption and load profile under either tariff.

[275] The Tribunal does not regulate the re-assignment or transfer of customers to alternative tariffs. The DNSP may decide to transfer customers if a customers' consumption or load profile has changed and it may longer not be appropriate for them to remain on the same tariff, or where the DNSP may change the structure of an existing tariff to suit the majority of customers and it does not suit some customers.

[276] Each customer has a standard network connection contract with its DNSP and a separate contract with its respective retailer who manages the relationship with the DNSP on the customer's behalf.

'Reasonable estimates' will also be required in the year following the movement (Year *t*), given that a full year of actual data will not be available when setting the prices in the next year.

A5.4 Value of p_{ij}^{t} when customers are transferred by the DNSP to an alternative tariff

As for the introduction of new tariffs or new tariff components, the p_{ij}^{t} prices of the corresponding 'origin network tariff' components will be used as the p_{ij}^{t} prices for the 'replacement tariff' components for the affected quantities (or the r_{j}^{t} in the price limits formula).[277]

Table A5.2 Example 2 Reasonable estimates for re-assigning some customers from the domestic flat rate tariff, to the domestic TOU tariff

Network tariff	Customers (number)	Billed consumption (Mwh) Non-TOU	Peak	Shoulder	Off-peak
Time of use (existing)	10,000		25,000	20,000	25,000
Domestic (existing)	(10,000)	(70,000)			

Assumes: Only some customers from the domestic tariff will be moved to the new TOU tariff (10,000 customers with a consumption of 70,000MWh). (Both tariffs remain in existence and will have remaining customers on the tariffs.)

Table A5.3 Example 2 (cont) Parameters in the WAPC and Price Limits formula for re-assigning some customers from the domestic flat rate tariff, to the domestic TOU tariff

Tariffs		p_{ij}^{t}	p_{ij}^{t+1}	q_{ij}^{t-1}
Domestic				
Fixed charge	$ pa per cust	$30	$32	(25,000 existing – 10,000) =15,000 customers
Variable rate	c/kWh	0.04	0.05	(200,000 existing - 70,000) = 130,000MWh
Domestic TOU - Existing customers				
Fixed charge	$ pa per cust	$22	$25	5,000 existing
Peak rate	c/kWh	0.09	0.095	10,000 MWh existing
Shoulder rate	c/kWh	0.05	0.05	10,000 MWh existing
Off-peak rate	c/kWh	0.02	0.025	10,000 MWh existing
Domestic TOU – Customers being transferred				
Fixed charge	$ pa per cust	$30 (as per domestic)	$25	10,000 customers
Peak rate	c/kWh	0.04(as per domestic)	0.095	25,000 MWh
Shoulder rate	c/kWh	0.04(as per domestic)	0.05	20,000 MWh
Off-peak rate	c/kWh	0.04(as per domestic)	0.025	25,000 MWh

277 This is only required for movements that occur in Year t+1, not for movements in Year *t*.

A5.5 The Tribunal's assessment of 'reasonable' estimates

When assessing the 'reasonableness' of quantity estimates provided, the Tribunal will take the following information into account:

a) The actual audited quantities sold in relevant units under the 'origin network tariff' in previous years.

b) A forecast of the number of distribution customers that the DNSP states they will move to the new tariff/component, and the reasons for the move.

c) A forecast of the number of distribution customers that the DNSP expects will remain on the 'origin network tariff'.

d) A forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that are to be moved to the new tariff/component.

e) A forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that will remain on the 'origin network tariff'.

f) A forecast of the DUOS tariff, and associated revenue, the DNSP expects will be payable by those distribution customers that will be moved the new tariff/component.

g) A forecast of the DUOS tariff, and associated revenue, the distributor expects will be payable by those distribution customers that will remain on the 'origin network tariff'.

h) The materiality of the 'reasonable estimates'

i) Further information as required by the Tribunal to support the numbers.

APPENDIX 6 GROWTH FORECASTS

As discussed in Chapter 4, growth forecasts affect the capital and operating costs of the DNSPs as well as the calculation of X-factors in the weighted average price cap.

Following the submission of the DNSPs forecasts, the Tribunal released a paper, entitled *Determining Sales Volumes for the 2004 Electricity Network Review*[278], in July 2003. The paper provided an overview of the demand forecasts submitted by the DNSPs and comparisons against historical, TransGrid and ABARE[279] forecasts. The DNSPs forecasts were in most cases lower than recent historic growth and other forecasts.

The responses to the Tribunal's paper called for an independent expert review of the growth forecasts. As a result, the Tribunal engaged McLennan Magasanik Associates (MMA) to:

- critique the DNSPs' low, medium and high growth scenarios
- determine throughput and demand forecasts for each DNSP.

This appendix provides an overview of the:

- DNSPs submitted growth forecasts, including underlying methodologies/ assumptions and TransGrid's projections as presented in the Tribunal's paper
- MMA draft report280
- MMA final report and how it took into account stakeholder comments on its draft report.

A6.1 Tribunal Paper

The Tribunal's *Determining Sales Volumes for the 2004 Electricity Network Review* paper outlined the theoretical incentive for the DNSPs to understate their volume forecasts in order to earn greater revenue than would be required to recoup costs. If actual sales turn out higher than forecast, DNSPs will earn more than is required to recoup costs. However if actual sales turn out lower than forecast then DNSP will not earn enough to recover their costs.

The paper noted that in terms of their most likely 'medium' growth scenarios, as set out in their April 2003 submissions, the DNSPs were projecting average annual growth rates for energy sales of between 1.5 and 2.0 per cent over the next determination period. Across all the DNSPs, the weighted average growth rate in energy sales was forecast to be 1.8 per cent.[281] In general, customer numbers were projected to grow at a slower rate than energy sales, between 0 and 2.3 per cent a year suggesting that consumption per customer is projected to increase.

278 Available on the Tribunal's website www.ipart.nsw.gov.au
279 Australian Bureau of Agricultural and Resource Economics.
280 Released for comment with the Tribunal's 2004-09 draft report and draft determination, January 2004.
281 The weights applied were actual customer numbers and energy sales for 2001/02.

The Tribunal's paper presented the growth forecasts submitted by the DNSPs and the methodologies and key drivers underlying their growth forecasts. These are reproduced below. In developing their submissions, the DNSPs were asked to provide estimates for low, medium and high growth scenarios, with the respective medium scenarios intended to be the 'most likely' scenario at the time submissions were prepared.

Under the medium growth scenario, the DNSPs were forecasting average annual growth rates of between 1.4 and 2.8 per cent for maximum demand in winter over the regulatory period. Maximum demand in summer was forecast to grow annually between 2.7 and 3.1 per cent. The fact that summer demand growth is forecast to grow faster than consumption has important implications for network costs and network pricing.

A6.2 DNSP forecasts

A6.2.1 EnergyAustralia

Methodology

EnergyAustralia's forecasts are based on modelling and analysis of historical and expected trends in energy market, and economic and demographic conditions in the EnergyAustralia region. The impacts of the following drivers are considered in developing the forecasts:

- economic activity
- residential customer numbers and customer characteristics, including appliance holdings
- electricity and gas prices
- fuel substitution and energy market share trends, including competition from natural gas and solar fuel sources
- energy efficiency improvements and environmental impacts
- short-term abnormal weather and day type impacts
- the political, economic and market uncertainties associated with future trends in the above issues.

The analysis features a disaggregated approach. The prospects for the residential and non-residential sectors are assessed and forecasted independently using statistical models. The residential forecast is based on an end-use forecasting approach that disaggregates electricity usage into 17 common electrical appliances. Key inputs into the forecast modelling are:

- Independent projections of residential sector customer numbers, provided by the National Institute of Economic and Industry Research (NIEIR), based upon their socioeconomic modelling and judgement about future population and housing trends in EnergyAustralia's network area.
- Projections of penetration rates for the appliances in the model, based upon historical trends and in-house judgement about future trends.
- Projections of annual average consumption for the appliances in the model, based upon load research information. Annual efficiency improvements for certain

appliances are incorporated. These efficiency gains were assumed on the basis of historical trends published in the Australian Greenhouse Office report *Strategic Study of Household Energy and Greenhouse Issues*, June 1998.

The non-residential forecast is based on an econometric model that identifies the statistical relationship between electrical energy consumption and New South Wales Gross State Product (GSP). The key input to the forecast modelling is projected economic activity within EnergyAustralia's region. The projections were sourced from NIEIR, but were increased by EnergyAustralia which has a view that NIEIR had overestimated the extent of drift of investment to the western part of Sydney, particularly in the context of the 2004-09 period. The NIEIR forecasts are included in Table A6.1 below.

In recognition of the inherent uncertainty in predicting future trends in the drivers of electricity consumption, EnergyAustralia analysed a range of projections corresponding to three economic and energy market scenarios (high, expected and low growth). As noted above, the detailed economic and demographic projections in each scenario have been provided by NIEIR. EnergyAustralia indicated that the scenarios that underpin the global forecasts are consistent with those used in NEMMCO's Statement of Opportunities. The forecast process features regular and ongoing reviews and updates of the forecasts and the forecast procedures.

Key assumptions and drivers of forecasts

Table A6.1 summarises the assumed trends in the key drivers of the global forecasts as set out in EnergyAustralia's April 2003 submission.

Table A6.1 Assumptions underlying EnergyAustralia's scenarios

Driver	Source	Projected Scenario outcome		
		Low	Medium	High
Economic Growth – NSW	NIEIR	1.8% pa	2.9% pa	3.8% pa
Economic Growth – EA	NIEIR	1.7% pa	2.8% pa	3.7%pa
Residential Customers:				
Overall Nos	NIEIR	0.7% pa	1.0% pa	1.2% pa
% with Air Conditioning	EA	50%	58%	63%
% with OP Water	EA	39%	40%	41%
% with Elec Heat/Cooking	EA	60%/65%	62%/67%	65%/70%
Average Consumption	EA models	-0.6% pa	-0.2% pa	0.3% pa
Weather Conditions		Average	Average	Average

Source: EnergyAustralia.

EnergyAustralia notes that energy growth over the 2004-09 period is expected to be lower than that expected during the current regulatory period. It suggests the reason for this is a combination of factors:

- marginally lower economic growth in the EnergyAustralia region, reflecting a weaker global economic outlook, the impact of increasing household debt and a gradual shift of activity toward western Sydney as transport and infrastructure improvements take effect

- lower growth in residential customer numbers, with growth returning to near long term rates after recent above average growth (fuelled by urban consolidation and strong dwelling building activity)
- stabilisation of average consumption per residential customer as a result of penetration of natural gas and solar as alternative fuel sources, and as air conditioning penetration growth slows as saturation levels are approached
- improvements in energy efficiency due to improved public awareness of energy efficiency and demand side management issues.[282]

A6.2.2 Integral Energy

Methodology

Integral Energy applied different methodologies for residential, non-residential and special categories such as inter-distributor transfers and streetlighting etc. These methodologies and resulting forecasts were subject to independent review. The methods applied were:

- end-use forecasting for energy consumption by residential customers based upon
  - forecast customer numbers
  - average consumption for each household appliance
  - forecast changes in penetration rates for each appliance
  - forecast efficiency improvements
- causal (econometric) forecasting for energy consumption by non-residential customers based upon the relationship between electricity consumption and NSW Gross State Product and real average electricity prices
- qualitative assessments of annual growth rates for the special categories of demand and
- forecasts of customer numbers based upon:
  - historical trends in population and number of dwellings in Integral's area as provided by ABS census data
  - historical information on the relationship between regional economic activity and number of non-residential customers and also specific regional planning information at a local government area level.

Key assumptions and drivers of forecasts

Underlying the non-residential forecasts are macroeconomic projections of New South Wales Gross State Product and regional economic activity. Integral commissioned National Institute of Economic and Industry Research (NIEIR) to develop projections for these aggregates. Table A6.2 summarises the specifications of scenarios underlying the NIEIR forecasts. Integral's submission does not identify the assumed values for these aggregates.

282 EnergyAustralia April 2003 submission, Appendix 3, pp 4-5.

Table A6.2 Assumptions underlying Integral's scenarios

Scenario	Assumptions
Medium (Base) Case	• Interest rates are held at near current levels. • Prudent government expenditure maintains growth. • Housing and equity prices stabilize towards the mid to late period. • Households begin to reduce debt relative to income; this increases savings but reduces household demand growth. • Growth in NSW GSP consistent with current economic forecasts.
High Case	• Strong public and private sector investment in Australian industries. • Full time employment growth and income increases leading to strong household driven growth.
Low Case	• Rapid world recovery places upward pressure on interest rates. • High debt service costs lead to very slow household consumption growth. • Falling house and equity prices result in wealth losses. • Government reduces infrastructure investment. • Increased import penetration stifles established industry sector growth. • Slow down in growth of NSW GSP compared to current economic forecasts.

Source: Integral Energy submission, pp 176-7.

Integral Energy identified some key factors influencing its forecasts:

- Significant demographic change in Integral's area with rapid growth in population, number of dwellings and household incomes.
- High and rapidly increasing penetration of weather sensitive appliances such as air conditioners and swimming pool pumps, influenced by high inland summer temperatures in Integral's area.
- A slowing in the economic growth rates affecting consumption in the non-residential sector which accounts for a large proportion of overall energy consumption. This will offset expected growth in the residential sector consumption.

A6.2.3 Country Energy

Methodology

Country Energy commissioned NIEIR to develop forecasts for customer numbers, energy sales and system demand. NIEIR developed forecasts on the basis of the old county council areas that were merged to form Country Energy's supply area. The forecast methodology involved a top down approach where the economic outlook for Australia is allocated between the states and then different regions within each state.[283] Country Energy's forecasts are based upon a combination of time series and regression econometric models that:

- forecast trends in energy sales
- determine the relationship between energy sales and economic and demographic variables and other key drivers of demand.

283 Country Energy submission, April 2003, pp 8-8.

Specifically, electricity sales are determined from a regression model based upon average electricity consumption for residential dwellings and the number of domestic premises, taking account of factors affecting energy consumption including real income growth, weather variables, population growth, gross state product and real electricity prices. In the model, non-residential electricity sales are linked to gross state product. Growth rates in customer numbers are based upon NIEIR's regional economic model which is based upon projections of gross regional product, population growth, construction activity and dwelling stock and have been tailored specifically to the region serviced by Country Energy.[284]

Full details of the methodology and key assumptions can be found in NIEIR's full report to Country Energy.[285]

Key assumptions and drivers of forecasts

The key macroeconomic assumptions identified in Country Energy's submission underlying Country Energy's projections are:

- Regional economy (defined as Country Energy's service area) forecast to grow at 2.1 per cent through to 2012 — 0.9 per cent under the state-wide average.
- Housing expected to grow at average rate of 1.2 per cent per annum.
- Population of Country Energy region is forecast to grow at an average rate of 0.5 per cent — 0.5 per cent below the statewide average. The population growth rate is lower than the expected increase in housing, suggesting a fall in the number of persons per dwelling.

The base case scenario for residential energy sales are assumed to be supported by high sales of air conditioning and an upturn in dwelling construction from 2004/05. Business sales are expected to mirror GSP growth in the Country Energy region. Country Energy's high and lower growth scenario are based upon higher and lower assumed GSP and population growth rates.

A6.2.4 Australian Inland

Australian Inland's projections are based upon overall network energy trends since 1989/90. Adjustments have been made for the consumption of its major CRNP customer that accounts for around one-third of Australian Inland's total supply. Including its CRNP customer, Australian Inland has experienced average growth of around 1.6 per cent. Over the past decade there has been significant variations across years and regions within Australian Inland's supply area.[286]

The key features of Australian Inland's sales projections are:

- a relatively flat projection for the CRNP customer under all scenarios
- general sales growth based upon historical growth trends for non CRNP customers
- the high growth scenario incorporating a potential new mining operation (still regarded as speculative in nature).

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284 Country Energy April 2003 submission, pp 8-10.
285 Country Energy April 2003 submission, Attachment C.
286 Australian Inland April 2003 submission, p 24.

Customer numbers are assumed to grow only slightly over the determination period. This reflects recent trends where population is tending to fall in the northern region centred around Broken Hill but rising in the southern region.[287]

A6.3 MMA Review

Responses to the Tribunal's July 2003 paper called for an expert review of the growth forecasts. Consequently, the Tribunal engaged McLennan Magasanik Associates (MMA) to review the demand forecasts submitted by the DNSPs and to prepare independent forecasts of customer numbers, energy consumption and peak demand for each DNSP. More specifically, it asked MMA to critique the DNSPs' low, medium and high growth scenarios and determine throughput and demand forecasts for each DNSP.

MMA delivered its draft report – *Review of demand forecasts for the 2004 electricity network review* in October 2003. The Tribunal invited stakeholders to make submissions on the report along with submissions on the Tribunal's draft report.[288]

MMA's review was based on requesting and clarifying historical, methodological and forecast data from the DNSPs and a desk-top review of other available material including further historical, demographic, weather and economic information. The methodology was restricted to publicly available data and data supplied by the DNSPs. This meant that analysis was generally possible only in two sectors, residential and non-residential, rather than by more disaggregated customer and size classes.

In summary, despite similar overall energy sales growth conclusions, MMA's draft disaggregated forecasts differed from those of the DNSPs by considerable amounts. MMA forecasted much higher residential growth for EnergyAustralia, but lower for the other DNSPs. They derived higher non-residential forecasts for Integral, Country Energy and Australian Inland, but reached a result similar to EnergyAustralia's non-residential modelling.

The largest difference was for EnergyAustralia. Differences between business and domestic customers largely cancelled out for Integral Energy.

MMA generally forecast higher peak demand growth than EnergyAustralia and Integral Energy. MMA forecast summer demand to grow at a much faster rate than overall consumption, with implications for network resource allocation.

MMA's projections were conservative in their assumptions. MMA draft report assumed that the 'comfort' factor (the trend growth residual unexplained by other usage factors) would decrease to half of its trend effect. MMA noted that it is difficult to predict a residual, given the lack of drivers to base the predictions upon. The half assumption allows for demand management/appliance efficiency effects – where demand management or improved appliance efficiency do not curb residential usage, demand will be higher than forecast.

The key approaches taken by the DNSPs in the forecasting methodology and MMA's comments on these in its draft report is summarised in Table A4.4 below.

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287 Personal communication, Australian Inland, 10 June 2003.

288 IPART, *NSW Electricity Distribution Pricing 2004/05-2008/09 – Draft Report*, January 2004.

Table A6.4 DNSP forecasting methodology and assumptions

Residential	Non-residential	MMA Comment
EnergyAustralia		
• Customer number forecast from NIEIR • Average usage per customer using EA appliance model	• Demonstrated relationship between electricity and Gross State Product (GSP) • Move to use same relationship with Network Region Gross Product (NRGP) • NIEIR forecast for GSP	• Forecast residential customer number growth is low compared to recent history • Appliance model suggests a significant shift in average usage from recent history • Strong relationship demonstrated between GSP (but not NRGP) and non-residential usage
Integral Energy		
• Customer number forecast based on history and NIEIR • Average usage per customer using IE appliance model	• Assumed relationship between non-residential electricity and GSP and real price of electricity • Assumed elasticities which reduced significantly over time • NIEIR forecast for GSP and price	• Forecast customer number growth seems high compared to recent history • Appliance model suggests a significant shift in average usage from recent history • No relationship demonstrated for the combined relationship between electricity, GSP and real price • Elasticities are based on judgement alone. This and the rapid reduction in elasticities are not supported • Need to separate forecasts for business and inter distributor transfers (IDT) in the non-residential sector
Country Energy		
• Prepared independently by NIEIR • Methodology not transparent	• Prepared independently by NIEIR • Methodology not transparent	• Historical information limited and very patchy. • NIEIR breakup of sectors is very different to that of Country Energy. • Forecast information is very different to that prepared by NIEIR in terms of sector numbers
Australian Inland Energy		
• No change in customer numbers • Trend for volume	• No change in customer numbers • Initial reduction in demand for major non-residential customer then flat • Trend for volume for remaining non-residential customers	• Very limited history • Changes to major customer not justified • Trend for other customers not justified

Source: MMA draft report, January 2004, pp i-ii.

MMA used a combination of historical trends and key drivers in producing independent forecasts for each DNSP.

Table A6.5 below summarises the key drivers of MMA's independent forecasting approach, and methodology as described in its draft report.

Table A6.5 MMA forecasting approach and methodology

Key Driver	MMA approach, methodology and comments
Residential customers	Combination of historical growth and forecasts, taking into account demographic data and forecasts from ABS, NIEIR and the Metropolitan Development Program from PlanningNSW. Customer growth is expected to moderate somewhat from recent history but not necessarily shift geographically.
Appliances and average usage per residential customer	Consideration given to history for both general tariff and off-peak loads, appliance models, penetration rates and energy efficiency trends. MMA approach balances historical trend and appliance modelling. Average use per customer is expected to moderate compared to recent history.
Economic Growth	MMA has established a strong relationship between GSP and electricity consumption for the state as a whole, with an elasticity of 0.87. MMA has confirmed the strong relationship between GSP and electricity consumption for the EA network with an elasticity of 0.8. The state wide relationship has been used for all DNSPs apart from EnergyAustralia. MMA has used a common NIEIR GSP forecasts across all DNSPs.
Weather Impact	MMA could not reproduce the impacts estimated by EnergyAustralia and Integral Energy. MMA has therefore used trend analysis.
Price	Both the changes to real price of electricity and the elasticity are very uncertain. MMA has not used any price forecasts or relationship in forecasting.
Cogeneration and major new projects	Own-use by expected additional cogeneration has been used to offset growth in the non-residential sector.
Maximum Demand	Based on MMA's residential appliance model, changes to customer numbers and customer peak usage for the residential sector and load factors for non-residential usage for each DNSP.
Demand Management	Continuation of energy appliance efficiency trends and reduced residential "comfort factor" growth. No other impact of current programs assumed on either energy or Maximum Demand.

Source: MMA draft report, January 2004, pp ii-iii.

A6.4 The MMA Final Report[289]

In producing its final report, MMA considered the comments made by stakeholders in response to the draft report. These comments have been summarised in Chapter 4, and are considered in more detail in the MMA final report itself: *Review of Demand Forecasts by the Electricity Distribution Network Service Providers for the 2004 Electricity Network Review* – April 2004, a copy of which is available on IPART's website. MMA also considered the impact of BASIX[290] – energy efficiency regulations expected to be introduced from July 2004.

The most detailed comments on the MMA draft report were provided by EnergyAustralia, Country Energy and the Energy Users Association of Australia (EUAA).

EnergyAustralia had suggested that MMA had over-stated its customer numbers forecasts. MMA found that EnergyAustralia had misunderstood the way MMA had used census data for the Baulkham Hills area, but also found an error in the treatment of Willoughby data which had an impact on residential customer numbers – MMA factored this change into its forecasts.

Following EnergyAustralia's comments, MMA also made adjustments to its 'comfort factor' to allow for the impact of the new BASIX energy efficiency regulations which are due to be implemented from July 2004. MMA also adjusted its forecasts to allow for reduced floor area growth trends, and greater potential for lighting efficiency gains.

MMA modelled the same residential changes for Integral Energy as it did for EnergyAustralia – however, it found that in the case of Integral Energy, this led to a small *increase* rather than a small *decrease* in the average residential usage growth forecast. MMA considered that such an increase would not be warranted, given that the introduction of BASIX is expected to have a *negative* impact on average residential usage – it therefore retained its initial estimate of a small decline in average residential usage (0.1 per cent pa).

EnergyAustralia made further arguments for lower growth rates as set out in its March 5 submission and the MMA report, but MMA was not persuaded by these arguments, citing recent trends amongst other evidence.

Country Energy criticised the MMA draft report for not using the forecasts derived by Country Energy's consultants NIEIR. MMA explained the difficulties that it had in evaluating this approach, given that the forecasts recommended by NIEIR did not match those the Country Energy had put forward in their submission. A further difficulty with forecasting for Country Energy was the lack of historic data. Following further discussions with Country Energy, in addition to a significant shift in sales figures for the year 2002/03 as described in Chapter 4, MMA concluded that the most appropriate course of action would be to adopt the 2002/03 audited figures as a base, given that Country Energy had expressed confidence in them, and to apply the NIEIR growth rates thereafter.

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289 McLennan, Magasanik Associates Pty Ltd, *Review of demand forecasts by the electricity distribution network service providers for the 2004 electricity network review,* April 2004.

290 Building Sustainability Index

MMA also addressed the comments of the EUAA in its final report. The EUAA had argued that the MMA forecasts had under-estimated the likely growth of air-conditioning penetration over the coming regulatory period. MMA noted that the EUAA's argument was based on ABS data for 1999 to 2002, while MMA's lower forecast was based on ABS data for 1994 to 2002. MMA noted some inconsistencies in the ABS data for 1994 and 1999, which led it to conclude that adopting a forecast based on the period 1999-2002 could lead to an *over*-estimate of air-conditioning penetration rates. MMA did not therefore consider it appropriate to make any amendments for the EUAA arguments.

APPENDIX 7 RATE OF RETURN

Within the building block methodology, the allowance for a return on capital covers the opportunity cost of capital invested in the DNSP by its owner. This allowance typically represents around 30 to 40 per cent of the DNSP's notional annual revenue requirement. It therefore has a significant impact on distribution prices and the financial outcomes for the DNSP and its customers.

The Tribunal calculates each DNSP's allowance for a return on capital by multiplying the value of the DNSP's regulatory asset base[291] by an appropriate rate of return. To determine what rate of return is appropriate, the Tribunal considers the DNSPs' and other stakeholders' submissions on this issue, and calculates a range for the weighted average cost of capital (WACC). It then makes a judgement on what rate of return within this WACC range is appropriate, given the competing objectives in the Code.[292] In particular, it aims to achieve an appropriate balance between the interests of customers and those of the DNSPs.

This appendix provides a detailed discussion of the Tribunal's final decision on the allowance for a rate of return.

A7.1 Final decision

The Tribunal decided that for the purpose of calculating the building block allowance for a return on capital, it will apply a real pre-tax rate of return of 7.0 per cent.

This decision was made with reference to the Tribunal's final finding on a WACC range of 6.1 to 7.5 per cent for the NSW DNSPs. In exercising its discretion within the Code to choose an appropriate rate of return within the WACC range, the Tribunal has considered the impacts on customers, businesses and shareholders to reach an appropriate balance.

291 For information on the Tribunal's decision on the regulatory asset base for each DNSP, see chapter 5.

292 The Tribunal as the jurisdictional regulator applying the Code, has discretion to choose a rate of return within the WACC range which achieves in its view, an appropriate balance between the Code objectives.

Table A7.1 WACC range and parameters

Parameter	Value
Nominal risk free rate (06/05/04)	5.9%
Inflation	2.5%
Real risk free rate (06/05/04)	3.3%
Market risk premium	5.0-6.0
Debt margin	0.9%-1.1%
Allowance for debt raising costs	0.125%
Debt to total assets	60%
Dividend imputation factor (gamma)	0.5
Tax rate	30%
Asset beta	0.35-0.45
Debt beta	0.06-0
Equity beta	0.78-1.11
Cost of equity (nominal post-tax)	9.8-12.6%
Cost of debt (nominal pre-tax)	6.9-7.1%
WACC (nominal post-tax)	6.1-7.1%
WACC (real pre-tax)	**6.1-7.5%**
WACC mid-point	**6.7%**

A7.2 Approach to calculating the WACC

The weighted average cost of capital (WACC) for a business is the expected cost of the various classes of capital it uses (such as equity and debt), weighted to take into account the proportion of its total capital that each class represents. In the regulatory context, the WACC represents the rate of return that regulators have applied when setting the allowed revenue and average tariffs for regulated businesses. The WACC and the CAPM are two of the factors the Tribunal considers in making the final decision on the rate of return.

The Tribunal uses the following formula to calculate the nominal post tax WACC for all DNSPs:

Formula 1 Nominal post tax WACC

$$WACC = \frac{R_e \times (1-t)}{\left[1 - t \times (1-\gamma)\right]} \times \left(\frac{E}{D+E}\right) + R_d \times (1-t) \times \frac{D}{D+E}$$

Where R_e is the cost of equity; R_d is the cost of debt; t is the statutory tax rate; γ is the value of imputation tax credits; E is the proportion of equity in capital structure; D is the proportion of debt in capital structure.

The cost of equity (R_e) is calculated using the Capital Asset Pricing Model (CAPM). The CAPM assumes that an investor requires additional returns to compensate for the non-diversifiable risks borne by investing in an asset. Thus, it asserts that the required rate of return on a risky asset is a function of the risk free rate (R_f), plus a risk premium that reflects the return on a well–diversified portfolio of assets over the risk free rate, (R_m-R_f), where R_m is the return on the market, scaled by the beta. Only non-diversifiable risk is rewarded by the CAPM. The cost of equity is then:

Formula 2 Capital asset pricing model (CAPM)

$$\mathrm{Re} = Rf + \beta_e \times (Rm - Rf)$$

Where Re is the Cost of equity; Rf is the Risk free rate; β_e is the Equity beta and Rm is the return on the market portfolio.

The equity beta (β_e) in Formula 2 is a measure of the covariance of the excess returns[293] of the asset with the excess returns of the equity market. Beta only measures risks that are non-diversifiable.

Equity and asset betas for the DNSPs' regulated assets are not readily observable in the market. Therefore, the Tribunal's approach is to estimate an asset beta that equates to the beta of a business that finances all of its assets solely with equity. To obtain the equity beta, it then re-levers the asset beta to reflect the benchmark capital structure of the DNSPs, using the Monkhouse formula:

Formula 3 Monkhouse formula

$$\beta_e = \beta_a(\beta_a - \beta_d)\times\left[1-\left(\frac{R_d}{1+R_d}\right)\times(1-\gamma)\times Tc\right]\times\frac{D}{E}$$

Where β_e is the equity beta; β_a is the asset beta; β_d is the debt beta; R_d is the cost of debt; γ is the value of imputation tax credits; Tc is the statutory tax rate; E is the proportion equity in capital structure and D is the proportion of debt in the capital structure.

A7.3 Summary of draft decision and stakeholder responses

The Tribunal's draft decision allowed for a pre-tax real rate of return of 6.8 per cent for all four NSW DNSPs. In coming to its draft decision, the Tribunal considered the impacts of a rate of return of 6.8 per cent on the different stakeholders and considered that it appropriately balanced their interests. The WACC range for the draft decision was 6.2 to 7.6 per cent, and was derived using the parameters shown in Table A7.2.

293 Excess returns are defined as the returns above the risk free rate.

Table A7.2 Draft decision WACC parameters

Parameter	Value
Nominal risk free rate (19/11/03)	5.8%
Inflation (19/11/03)	2.3%
Real risk free rate (19/11/03)	3.5%
Market risk premium	5.0-6.0
Debt margin	0.9%-1.1%
Debt to total assets	60%
Dividend imputation factor (gamma)	0.5
Tax rate	30%
Asset beta	0.35-0.45
Debt beta	0.06-0
Equity beta	0.78-1.11
Cost of equity (nominal post-tax)	9.7%-12.5%
Cost of debt (nominal pre-tax)	6.7-6.9%
WACC (nominal post-tax)	6.0-7.0 %
WACC (real pre-tax)	**6.2-7.6%**

The DNSPs and NSW Treasury responded to the draft decisions, submitting that the proposed 6.8 per cent rate of return was too low. They pointed out that this rate is lower than the pre-tax real rate of return allowed by other Australian regulators in recent electricity network distribution services decisions, and does not reflect the commercial return required by investors to invest in energy network infrastructure.

On the other hand, the Energy Users Association of Australia and the Energy Markets Reform Forum submitted that a 6.8 per cent rate of return is high compared to UK regulatory decisions. They commented that such a rate of return implies that Australian utilities are less efficient than UK utilities.

These and other stakeholders also raised other issues related to the value of the WACC range changes in individual WACC parameter values, and the treatment of asymmetric risk:

- The DNSPs, the Energy Networks Association, AGLGN and NSW Treasury questioned the consistency of changes in the WACC parameters used in the draft decision compared to those used for 1999 determination. They argued that the Tribunal had selectively changed parameters that would lower the WACC, and had left parameters that would result in a higher WACC unchanged.
- Energy Australia commented that the draft decision on the rate of return is in no way a conservative estimate as purported by the Tribunal in its draft report.
- Integral Energy argued that the draft decision on the WACC fails to meet the Tribunal's obligation under the Code to provide the DNSP with a risk-adjusted cash flow rate of return comparable to that required by investors in commercial enterprises facing similar business risks to it.
- The Energy Users Association of Australia argued that the Tribunal should adopt a vanilla post tax form of the WACC, and use forward-looking estimates for values of all key parameters in the CAPM.

Stakeholders also responded to the Tribunal's decisions on some of the individual parameter values the Tribunal used to calculate the WACC range for the draft determination. These comments and the Tribunal's considerations of them are discussed in section A7.4 below.

A7.4 Tribunal considerations in making its final decisions

In finalising its decisions on the value of the individual parameters used to calculate the WACC range and an appropriate rate of return within this range, the Tribunal carefully considered all issues raised by stakeholders.

Its draft decisions on five of the individual parameters were not contested by stakeholders. The Tribunal's final decisions on these parameters are therefore the same as its draft decisions. The parameters concerned are:

- **The nominal risk free rate.** The Tribunal decided to use a 20-day average of the 10-year Commonwealth bond yield to determine the nominal risk free rate. On the date of the final decision, 6 May 2004, this rate was 5.9 per cent.
- **The real risk free rate.** The Tribunal decided to use a 20-day average of the yields on 2010 and 2015 Treasury indexed bonds to derive the real risk free rate. On the date of the final decision this rate was 3.3 per cent.
- **Inflation.** The Tribunal decided to use the difference between the nominal and the real risk free rates (using the Fisher equation), to obtain an estimate of expected inflation. On the date of the final decision this rate was 2.3 per cent.
- **Debt to total assets**. The Tribunal decided to use an industry benchmark capital structure of 60 per cent gearing.
- **The tax rate**. The Tribunal decided to include an allowance for taxation in the real pre-tax WACC. This tax allowance is based on the statutory tax rate. At the time of the final decision, the statutory tax rate for businesses operating in Australia was 30 per cent.

The remainder of this section discusses the Tribunal's considerations and analysis in reaching its final decisions on the allowed rate of return; the other WACC parameters (including the market risk premium, the debt margin, the allowance for debt raising costs, the dividend imputation factor or gamma, the debt beta, and the asset and equity betas); and asymmetric risk.

A7.4.1 The allowed rate of return

For the final determination, the Tribunal applied a real pre-tax rate of return of 7.0 per cent when calculating the building block allowance for the return on capital. This is a higher rate of return than applied in the draft decision, when the Tribunal applied a pre-tax real rate of return of 6.8 per cent.

The Tribunal took the view that its key consideration when making its final decision on the rate of return for this determination should be to appropriately balance the interests of all stakeholders. It undertook further analysis on the rate of return, to compare the impact of different rates of return on customers' final nominal electricity bills, and on the DNSPs' financial position. This analysis indicated that:

- increasing the rate of return from 6.8 per cent to 7.0 per cent would have little impact on customers' final nominal bills, but would go some way, albeit modestly, towards addressing some of the DNSPs' concerns
- increasing the rate of return to 7.5 per cent, as requested by the DNSPs, would improve the DNSPs' financial position substantially, but would have a much more significant impact on customers' final bills.

Based on this analysis, it considers that the benefits to customers of maintaining the 6.8 per cent rate of return would not be sufficiently large to warrant a further deterioration in the DNSPs' financial position. However, increasing the rate of return to 7.5 per cent (or almost the top of the WACC range) would result in an unacceptable outcome for customers, particularly in light of the already substantial price increases being sought by the DNSPs It therefore concluded that on balance, increasing the rate of return to 7.0 per cent is reasonable and justified.

A7.4.2 The market risk premium

The Tribunal decided that a market risk premium estimate of 5.0 to 6.0 per cent is appropriate, based on historical studies of the market risk premium (MRP). The draft decision on the MRP was the same as its final decision, but was based on historical studies as well as forward-looking estimates of the MRP.

In making its final decision, the Tribunal considered submissions from the DNSPs and NSW Treasury, which argued that it should rely on historical evidence on the MRP rather than forward-looking studies. The Tribunal also considered the Energy Markets Forum's comments and the study it submitted, which argues that the MRP should be estimated using a forward-looking approach. The evidence provided by this study indicates that the MRP should be around 3 per cent.

The Tribunal concluded that the approach it uses to estimate the MRP should be consistent with a reasonable decision-making process for investments in infrastructure assets. As these investments are made for a longer period of time than the 10-year period used in the study submitted by the Energy Markets Forum, the Tribunal considers that the forward looking approach described in that study is not appropriate for its purposes, as it does not take into account the actual time commitment of investments in infrastructure assets.

The Tribunal also considered stakeholder comments that it did not use a consistent approach in estimating the WACC parameters for the draft determination. The main issue raised was that the Tribunal used a backward-looking approach to estimate the WACC parameters that are not directly observable in the market, *except* the MRP. To estimate this parameter, it used a hybrid approach that relied on historical studies and forward-looking research, particularly the Jardine Fleming Capital Markets survey conducted in 2001.

In addition, it considered stakeholder comments that the Tribunal should not base its decisions on the Jardine Fleming Capital Markets survey, because:

- the wording of the survey question is inappropriate, in that it asked what MRP the finance professionals expect and not what investors expect
- the survey is based on a small sample (61)

- research in financial economics suggests that forward estimates of MRP have consistently understated the MRP in the past.

Finally, the Tribunal considered stakeholder views that it should use an MRP estimate of 6.0 per cent because this is the value of the MRP implied by historical studies, and because all other Australian regulators use an MRP estimate of 6 per cent.

The Tribunal does not consider that the fact that other regulators use an MRP estimate of 6 per cent is sufficient evidence that this is the most appropriate and accurate estimate of this parameter. In addition, it undertook its own review of a range of historical studies of the MRP (see Table A7.3). It found that several of these studies did estimate the MRP to be around 6 per cent. However, to reflect the findings of all the studies, an MRP derived from historical studies would be between 4.8 and 8.1 per cent, implying a midpoint of 6.5 per cent.

Table A7.3 Historical MRP Studies

Source	Methodology	Period	MRP
AGSM[294]	Arithmetic average, incl. Oct 1987	1964-1995	6.2
	Arithmetic average, excl. Oct 1987	1964-1995	8.1
	Arithmetic average	1964-1998	4.8
	Arithmetic average, incl. Oct 1987	1964-Sep 2000	6.2
	Arithmetic average, excl. Oct 1987	1964-Sep 2000	7.7
Officer	Arithmetic mean[295]	1882-1987	7.9
	Arithmetic mean[296]	1882-2001	7.2
	Arithmetic mean[297]	1946-1991	6.0-6.5
Hathaway[298]	Arithmetic mean	1882-1991	7.7
	Arithmetic mean	1947-1991	6.6
Gray[299]	Arithmetic mean	1883-2000	7.3
Dimson, Marsh & Staunton[300]	Arithmetic mean	1900-2000	7.6

The Tribunal believes that estimates of the MRP depend considerably on the underlying methodology used, and the time periods chosen for study, as evidenced by the range of estimates available. Given that there is no evidence to indicate that any of the studies on Table A7.3 are more valid than others, and the uncertainties surrounding the estimates, it believes that there is insufficient evidence to justify changing its MRP range from 5.0 to 6.0 per cent.

294 All AGSM studies in this table are sourced from: IPART, *Regulation of NSW Electricity Distribution Networks*, section 5.4.2, Table 5.4, December 1999.

295 Officer, R. "Rates of return to shares, bond yields and inflation rates: An historical perspective", in *Share Markets and Portfolio Theory; Readings and Australian Evidence*, 2ed, University of Queensland Press, 1992.

296 E. Dimson, P. Marsh and M. Staunton, *Triumph of the Optimist: 101 years of Global Investment Returns*, Princeton University Press, 2002.

297 Officer, R. "Rates of return to shares, bond yields and inflation rates: An historical perspective", in *Share Markets and Portfolio Theory; Readings and Australian Evidence*, 2ed, University of Queensland Press, 1992.

298 Hathaway, N. *unpublished manuscript.*

299 Gray, 2001.

300 E. Dimson, P. Marsh and M. Staunton, *Triumph of the Optimist: 101 years of Global Investment Returns*, Princeton University Press, 2002.

A.7.3 Debt margin and allowance for debt raising

The Tribunal decided to base the debt margin on investment grade Australian debt with a maturity of 10 years, and to add an explicit allowance for debt raising costs of 12.5 basis points on top of the debt margin. For the draft determination, the Tribunal used a debt margin of 0.9 to 1.1 per cent, based on observed market yields for BBB+ to BBB rated Australian bonds and included an implicit allowance for debt raising costs.

Considerations in relation to the debt margin

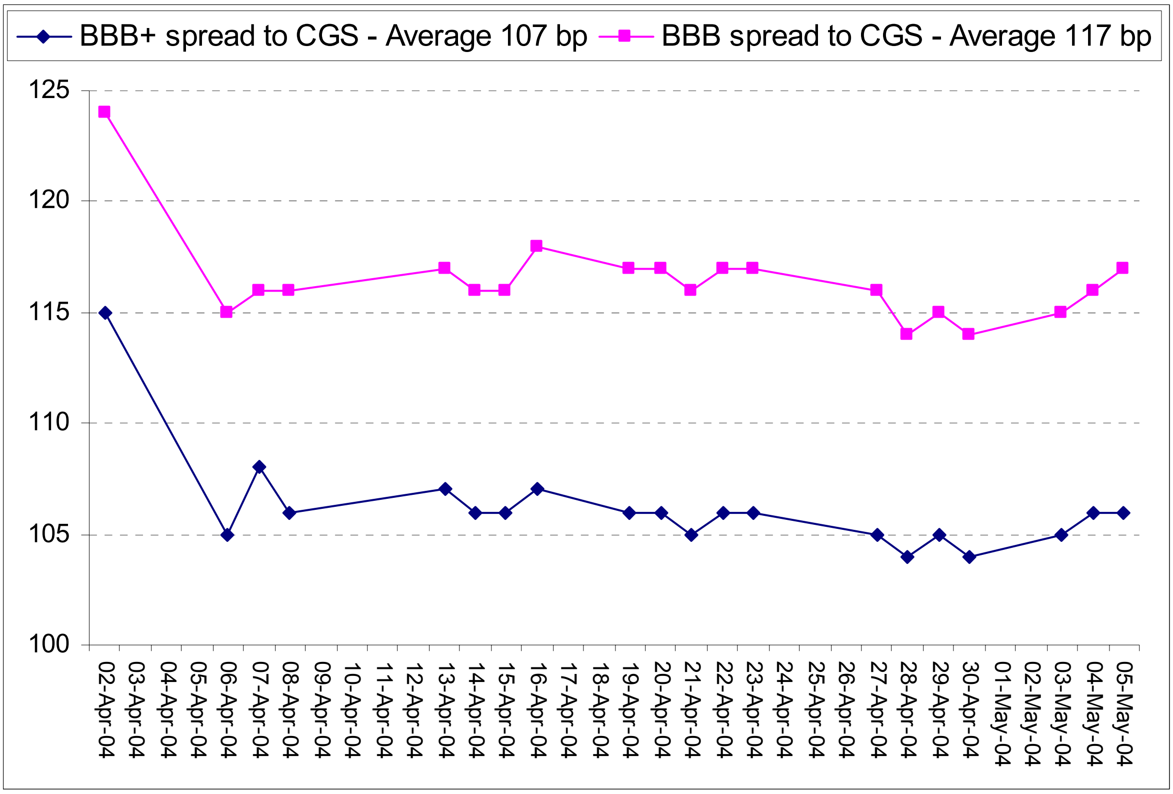
The Tribunal considered the submissions from the DNSPs and NSW Treasury, which argued that the debt margin allowed by the Tribunal is too low, based on the observation that credit margins provided by the CBASpectrum for BBB rated debt are considerably higher than the margin of 0.9 to 1.1 per cent used in the draft determination.

The Tribunal notes that the NSW DNSPs borrow their debt requirements through Treasury Corporation. The NSW State Government currently has a credit rating of AAA. To ensure competitive neutrality, NSW Treasury charges Government owned enterprises a government guarantee charge. This charge reflects the differential between the NSW State Government's debt margins and that of the borrower as a standalone entity. NSW Treasury currently bases this interest differential using the US bond market.

The Tribunal uses a credit rating that reflects the benchmark capital structure. In its draft report, it indicated that it intended to use a benchmark credit rating of BBB+ to BBB. It is aware that there can be a considerable difference in credit margins between BBB+ and BBB rated debt.

For its final determination, the Tribunal decided to use the yields of investment grade Australian bonds as an indicator of whether its debt margin estimate is reasonable compared to current market yields. At the time of this determination, it obtained the observed yields on investment grade Australian bonds with a maturity of 10 years from the CBASpectrum (Figure A7.2).

Figure A7.2 Yields on investment grade Australian bonds



Source: CBASpectrum.

These yields indicate that 20-day average of BBB+ and BBB rated Australian bonds were between 107 and 117 basis points. The Tribunal therefore considers that a debt margin of 90 to 110 basis points (or 0.9 to 1.1 per cent) is reasonable, given that not all debt issues are rated as low as BBB+ or BBB.

Considerations in relation to the allowance for debt raising costs

The Tribunal considered the submissions from several stakeholders that argued for an explicit allowance for debt raising costs, based on the observation that the Tribunal's debt margin is at the lower end of the range of possible debt margins for its benchmark credit rating.

The Tribunal considers that this argument is valid. It based its final decision on the debt margin on the assumption that all debt financing is of a long-term nature. This is reflected in the benchmark maturity assumption of 10 years. However, market evidence suggests that long-term investments other than project finance of more than five years may be difficult to obtain in the Australian market. This implies that businesses frequently have to refinance their debt.

Table A7.4 Debt raising costs

Date	Regulator	Business	Debt raising cost	Total debt margin	Benchmark credit rating
Mar-04	ICRC	ActewAGL	12.5	124.5	BBB+
Jan-04	ESCOSA	ETSA Utilities (preliminary)	12.5	162.5	BBB+
Dec-02	ACCC	SPI Powernet	10.5	120.5	A
Dec-02	ACCC	ElectraNet	10.5	121.5	A
Nov-02	ACCC	GasNet	25	184	BBB+
Oct-02	ESC	Vic. Gas distributors	5	165	BBB+

The Tribunal considers that it is reasonable to assume that the DNSPs incur costs above the debt margin allowed by the Tribunal relating to:

- debt raising costs
- debt refinancing costs.

It therefore decided to include an explicit allowance for debt raising costs of 12.5 basis points in its final decision. It notes that other Australian regulators have included an explicit allowance for debt raising costs, ranging from 5 to 25 basis points (Table A7.4). It believes that 12.5 basis points is reasonable.

A7.4.4 Value of dividend imputation credits, or gamma

The Tribunal decided to use a gamma of 0.5. This is the same as the draft decision on gamma, which was based on research studies that indicated that the value of gamma lies within 0.4 to 0.6.

The Tribunal considered stakeholder submissions that argued that it had not provided sufficient evidence to justify using a different value for gamma than it used in the 1999 determination, which was 0.3-0.5. It also considered Country Energy view that the research evidence used by the Tribunal indicates that the value of gamma lies within a 0.3-0.5 range rather than a 0.4-0.6 range.

The evidence presented by Country Energy specifically referred to two studies used in the Tribunal's draft decision. Country Energy argued that the Tribunal's analysis was incomplete in that it only took into account the utilisation component of gamma from the Hathaway & Officer (1999) studies, and that the correct methodology is to account for both the access and the utilisation factor. Access refers to the proportion of franking credits that are distributed by companies, whereas the utilisation component refers to the amount of imputation tax credits that can be offset against the personal tax liabilities of the investor. The study used by the Tribunal indicates that the access component of imputation tax credits is 80 per cent and that the utilisation component is 60 per cent. Compounding these two (0.8×0.6), leads to a gamma value of 0.48.

The Tribunal acknowledges that the approach Country Energy outlined in its submission is correct, and it has used the corrected values in its final decision. Table A7.5 summarises the studies used by the Tribunal in coming to its final decision.

Table A7.5 Gamma studies

Study	Method	Gamma
Cannavan, Finn & Gray[301] (2001)	Futures and LEPOs	0
Twite & Wood[302] (2002)	Derivative prices	0.45
Hathaway & Officer[303] (1999)	Aggregate tax statistics	0.48
	Dividend drop-off	0.44 (all companies)
		0.49 (large companies)
Bruckner, Dews and White[304] (1994)	Dividend drop-off	0.335-0.685
Brown & Clarke[305] (1993)	Dividend drop-off	0.72
Walker & Partington[306] (1999)	Dividend drop-off	0.88 or 0.96
Chu & Partington[307] (2001)	Rights issues	Close to 1

The studies presented in Table A7.5 indicate that there is no conclusive evidence on the exact value investors attach to imputation tax credits. However, the numbers presented in Table A7.5 support the Tribunal's decision of adopting a gamma of 0.5. Consequently, the Tribunal's final decision on the gamma is to adopt a point estimate of 0.5.

A7.4.5 Debt beta

The Tribunal decided to use a debt beta of 0.06 to 0. This decision is the same as its draft decision. In reaching its final decision, the Tribunal considered NSW Treasury's argument that the debt beta should be zero, consistent with common market practice.

The Tribunal notes that for the 1999 determination, it used a debt beta of 0.6. For its draft determination, it decided to use a debt beta of 0.06 to 0, to reflect the capital market's view that the debt beta is equal to zero. However, it decided *not* to go further and use a debt of zero itself, to reflect the studies by Elton et al[308] and the Allen Consulting Group,[309] which demonstrate that the debt beta is greater than zero.

As the Tribunal has not received any *additional* evidence that the debt beta should be zero, and it considers that it cannot disregard the studies that indicate that the debt beta value is low but above zero, its final decision is to use a debt beta range of 0.06 to 0.

301 Cannavan, Finn & Gray, "The value of dividend imputation tax credits in Australia" working paper, University of Queensland and Duke University, 2002.

302 Twite & Wood, "The Pricing of Australian Imputation Tax Credits: Evidence form Individual Share Futures Contracts", working paper, AGSM, 2002, p 22.

303 Hathaway & Officer, "The Value of Imputation Tax Credits", working paper, Melbourne Business School, 1999.

304 Brukner, Dews & White, "Capturing Value from Dividend Imputation"' McKinsey and Company, 1994.

305 Brown & Clarke, "The ex dividend day behaviour of Australian share prices before and after dividend imputation", Australian Journal of Management 18, 1, 1993.

306 Walker & Partington, "The value of dividends: evidence from cum-dividend trading in the ex-dividend period" Accounting and Finance, vol 39, 1999.

307 Chu, H., Partington G. "The market value of dividends: theory and evidence from a new method", working paper, UTS, 2001.

308 Elton et al. "Explaining the rate spread on corporate bonds" The Journal of Finance. Vol LVI, No. 1, 2001, pp 247-277.

309 The Allen Consulting Group *Empirical evidence on proxy beta values for regulated gas transmission activities*, Report for the ACCC, 2002.

A7.4.6 Asset and equity betas

The Tribunal decided to use an asset beta range of 0.35 to 0.45, and to calculate an equity beta range of 0.78 to 1.11 using the Monkhouse formula. Both these decisions are the same as the draft decisions.

In making its final decisions, the Tribunal did further analysis on beta values of comparable Australian businesses. It also considered stakeholder responses to its draft decisions, including:

- Energy Australia's view that the Tribunal should not rely on market estimates of comparable companies.
- Integral Energy's view that the introduction of the weighted average price cap results in an increase in non-diversifiable risk, which should be reflected in a higher equity beta than used for the 1999 determination.
- Country Energy's and NSW Treasury's criticism of the comparison to the market beta of 1. They argue that the market has a different gearing than that used by the Tribunal. Consequently, a direct comparison of the two is not possible.
- The EMRF's submission that the equity beta is too high given current market conditions, and that based on a study by Headberry Partners P/L and Bob Lim, an equity beta of 0.5 to 0.7 is appropriate.

The equity beta represents the covariance of the excess returns[310] of a share with the excess returns on the market. The asset beta measures the same covariance if the assets of a business were 100 per cent equity financed. As the regulatory asset base of a utility is not publicly traded, the Tribunal has to estimate an equity beta.

The estimate of the equity beta must reflect the degree of leverage of the regulated business. When using proxy betas derived from comparable Australian companies, it is crucial to:

- remove the effect of leverage by converting the equity beta to an asset beta
- re-lever the asset beta using the assumed gearing ratio to obtain an estimate of the equity beta.

Recent evidence suggests that it is possible, to some extent, to estimate a proxy equity beta by using a set of comparable Australian companies. In its 2003 Review of Gas Access Arrangements, the ESC (Victoria) thoroughly discussed the possibility of using a pool of comparable Australian publicly listed companies to derive a proxy equity beta. It found that by doing so, it would arrive at a substantially lower equity beta than in previous decisions. It therefore concluded that "…the derivation of the proxy is one of the matters upon which conservative exercise of judgement is justified."[311]

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310 Excess returns are defined as the excess returns above the risk free rate.
311 ESC of Victoria, *2003 Review of Gas Access Arrangements*, 2003.

There is a limited number of utility companies traded on the Australian Stock Exchange. Those that are traded are not always directly comparable to the asset bases of the businesses the Tribunal regulates. Table A7.6 provides the equity betas and gearing levels of some of the publicly traded utilities in Australia.[312]

Table A7.6 Publicly traded utilities betas and gearing

Company (June 2003)	Equity beta	Gearing
AGL	-0.01	52%
Envestra	0.39	80%

To establish a proxy beta for the NSW DNSPs, the Tribunal must de-lever the proxy equity beta to an asset beta and then re-lever it to reflect the target capital structure of 60 per cent gearing. To do this, it uses the Monkhouse formula.

By applying this formula to the information from Table A7.6, it derived the equity beta estimates on Table A7.7. These estimates suggest that equity betas derived from a pool of comparable companies would be much lower than those the Tribunal has used in the past.

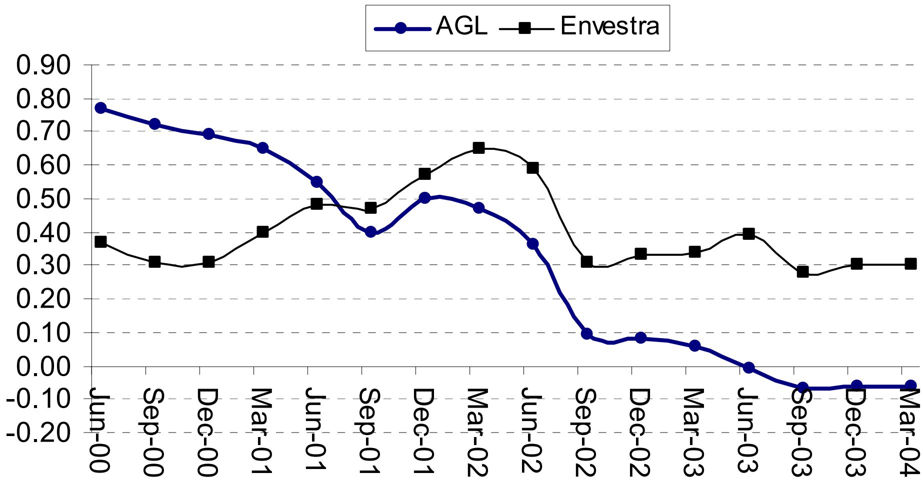
Table A7.7 Equity betas

	Equity beta	Asset beta Beta debt = 0	Asset beta Beta debt = 0.06	Equity beta Beta debt = 0	Equity beta Beta debt = 0.06
AGL	-0.01	-0.01	0.01	-0.01	-0.01
Envestra	0.39	0.22	0.24	0.39	0.39
Simple average	0.19	0.11	0.13	0.19	0.19

An alternative approach would be to use actual market data as an objective reflection of what a rational investor expects to earn from an investment for a given level of risk. The Tribunal collected a time series of beta estimates obtained from the AGSM risk measurement service (Figure A7.3). These data seem to indicate that beta values have fallen over the last years.

312 Equity betas: AGSM Risk Management Services, June 2003. Gearing levels: Standard & Poor's Australia and New Zealand Credit Stats 2003, June 2003, pp 31-32, cited in ACCC, *Final Decision: Moomba to Sydney Pipelines System Access Arrangement*, 2003.

Figure A7.3 Equity beta trends[313]



The Tribunal sees considerable merit in deriving a proxy beta that is based on the latest estimates of companies for sufficiently comparable companies. In the past, it has indicated that it prefers to use financial market data. The difficulty that arises with the use of financial market data is that neither the beta, nor the exact capital structure of the regulatory asset base is known. It is however possible to take into account the trend of beta values for comparable companies when estimating the beta values for the regulatory asset base of NSW DNSPs.

Given the above evidence of decreasing betas of comparable Australian companies, the Tribunal considers that there is not sufficient evidence to increase the range of asset beta values to those submitted by the DNSPs and NSW Treasury. In addition, while it recognises that due to the lack of market data, the DNSPs face some degree of regulatory uncertainty in relation to the choice of the equity beta, it believes that the evidence for lower equity betas is not compelling enough to warrant it using a lower equity beta in the final decision.

A7.4.7 Asymmetric risk

The Tribunal decided not to make any allowances for asymmetric risk in its WACC estimate. This decision is the same as the draft decision, which was based on the fact that an allowance for asymmetric risk in the WACC would be inconsistent with the assumptions underlying the CAPM. The CAPM only accounts for non-diversifiable risk.

In making its final decision, the Tribunal considered the DNSPs' responses to its draft report. The DNSPs argued that they face a number of asymmetric risks that are not reflected in the WACC, including:

- regulatory risk
- insurance
- asset stranding
- statutory changes
- easements

313 AGSM Risk Management Services, June 2003.

- risks arising form the introduction of the weighted average price cap.

The assumption that these risks are asymmetric is based on the argument that the regulatory framework within which the DNSPs operate exposes them to limited upside risk and a theoretically unlimited downside risk. Implicit in this is the assumption that when a regulated business achieves cost savings, the regulator will return these savings to customers, but when it faces unforeseen cost increases, the business must bear the loss. Unlike unregulated businesses, most regulated businesses have an obligation to supply regardless of changing costs or growth in demand.

The CAPM postulates that, in equilibrium, the expected return of a business should be related to its market risk: a security with higher market risk (higher beta) should offer a higher expected return than a security with a lower market risk (lower beta). The diversifiable risk is irrelevant. In particular, a security with high total risk (high σ^2), but low beta will (in equilibrium) have a lower expected return than another security with a higher beta and lower total risk (that is, a security with lower diversifiable risk). The reason for this is that the diversifiable risk can be diversified away (by investing in other securities), while the market risk cannot.

The DNSPs and other stakeholders argued that this assumption does not hold in the case of regulated businesses, as the counterparty to these risks is the consumer. For example, NECG argued, that the "beneficiaries of regulation are final consumers, and since investors cannot directly purchase a claim on the residual income of final consumers, their ability to avoid this type of risk is limited".[314] But in a footnote, NECG acknowledged that indirect diversification may be obtained by investing in other negatively correlated businesses.

However, the Tribunal notes that, according to modern portfolio theory (MPT), the only risk that should be priced in the CAPM is the market risk. Any firm-specific risk can be diversified away through the construction of a minimum variance portfolio. The argument that the consumer is the counterparty to asymmetric risks does not hold, as investors can diversify their investments regardless of who the counterparty to any specific risk may be.

The Tribunal particularly considered Country Energy's argument that the CAPM is based on a number of assumptions including that returns are normally distributed, and that in the presence of asymmetric risk, this assumption is violated because this type of risk represents a truncation of returns.

The Tribunal has previously acknowledged that the CAPM is based on a number of assumptions that are unlikely to hold perfectly in the real world. It uses the model because it is generally recognised to be the best model currently available. However, it does not consider it theoretically correct to increase the equity beta within the CAPM based on the argument that the assumption of normally distributed returns is violated. It believes that if asymmetric risk represents a truncation of returns and consequently violates the CAPM assumption of normally distributed returns, a different model should be used. In the absence of a better model and sufficient evidence that asymmetric risk is the only risk that violates the assumption of normally distributed returns, the Tribunal considers it correct to account for these risks elsewhere in the building block model where necessary.

314 Network Economics Consulting Group, *Regulatory Risk*, 2001.

APPENDIX 8 APPROACH TO DETERMINING THE X-FACTOR

The Tribunal considered a number of possible methodologies for determining the X-factors for the Weighted Average Price Cap. This Appendix provides an explanation of the approaches considered by the Tribunal and the Tribunal's evaluation of each method's outcomes. The Code does not have any specific requirements relating to the appropriate path for calculating X-factors. The Tribunal has had regard to the general provisions of the Code outlining the key objectives and principles for the regulation of network prices.

A8.1 Options considered

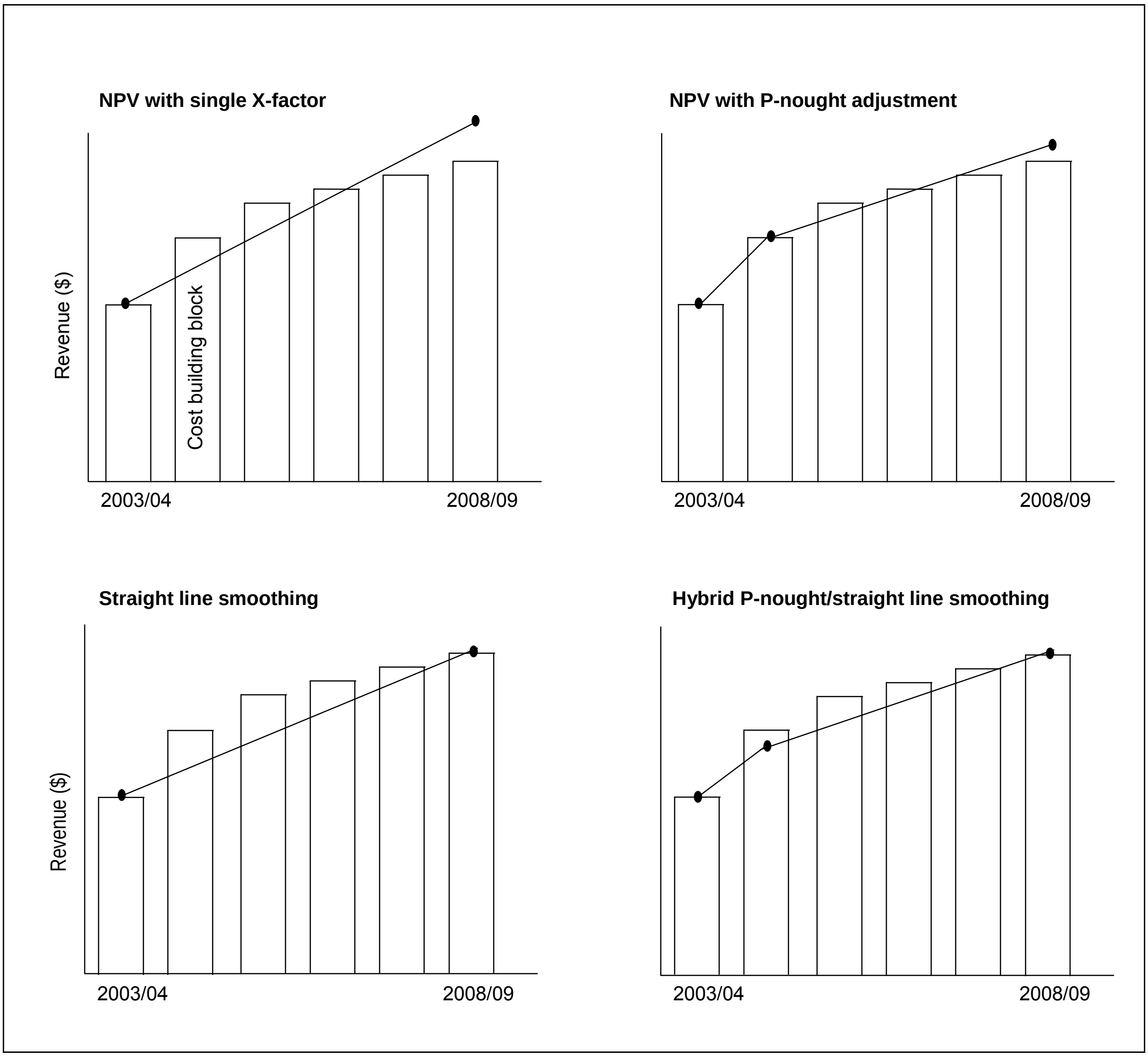
The Tribunal's issues paper and financial modelling contained three broad approaches to calculating the amount by which prices are allowed to move in real terms. These were:

- **Net Present Value (NPV) approach with single X-factor** — a single X-factor is set to ensure expected revenue equals expected notional revenue requirements (in NPV terms).
- **NPV approach with P-nought adjustment** — an initial X-factor (P-nought) allows prices to rise sufficiently to ensure expected revenue is equal to notional revenue requirements in the first year, with a second X-factor, to apply over the remainder of the regulatory period, set at a level that ensures expected revenue equals expected notional revenue requirements over the life of the regulatory period.
- **Straight line revenue smoothing (glide path)**— a single X-factor is set such that prices change smoothly over the regulatory period in real terms to ensure that the expected revenue in the final year of the regulatory period equals the notional revenue requirements in that year.

In addition to these three approaches, Country Energy and Australian Inland have proposed a hybrid approach combining a P-nought adjustment with straight line revenue smoothing. This approach involves two X-factors. An initial X-factor is set to deliver a desired P-nought adjustment to prices. A second X-factor determines a constant real price path that would ensure expected revenue in the final year of the regulatory period is equal to the expected notional revenue requirement in that year (as under the straight line approach).

Figure A8.1 illustrates the approximate revenue paths under these approaches.

Figure A8.1 Revenue paths under alternate approaches



Note: The actual revenue paths under these approaches might be less smooth than illustrated if annual volume growth is volatile.

Each of these approaches has different implications for:

- **Price stability.** How volatile will the price path be under this approach? Will customers face large jumps in prices and/or changes in direction (increases followed by falls) during the regulatory period?
- **Revenue recovery.** Does the option allow for recovery of notional revenue requirements? Does it allow a reasonable return on investment?
- **Transitional issues into the regulatory period commencing 2009.** What does the option imply for revenue in the final year of the 2004-09 regulatory period? Is the notional revenue requirement for the final year (2008/09) over or under recovered, potentially requiring a realignment of revenues going into the next regulatory period?
- **Implications for incentives.** What implications are there for incentives for efficient operation and investment? Does the approach allow businesses some form of efficiency carryover?

- **Regulatory consistency.** How does the option compare with the approach in the 1999 determination? What are the implications for the 2009 determination?

A8.2 Analysis of methodologies

The four options for setting the price path were evaluated by the Tribunal in terms of the above five criteria below.

Table A8.1 below summarises how each of the proposed X-factor methodologies rate against the abovementioned criteria and shows that each option rates differently against each of the above criteria.

Given the current circumstances, the straight line smoothing is likely to have least impact on prices faced by customers. It also offers the greatest level of incentives for efficiency gains but at a cost in terms of the amount of revenue raised by the DNSPs. The single X-factor NPV approach offers a smooth price path with higher annual price increases but has weak incentives for cost efficiencies. The NPV P-nought approach also offers weak incentives for efficiency improvements but offers the option of a higher initial price increase with lower annual rises thereafter, while fully recovering revenue. The Tribunal has had to consider whether stakeholders are likely to prefer larger ongoing annual increases over a more significant initial increase followed by smaller annual price increases or vice versa.

The trade-off among options between the incentives offered and the level of revenue recovery is readily apparent. The options that have the greatest incentive properties are likely to under-recover expected costs in the 2004-09 regulatory period.

Under the straight line approach efficiency 'losses' (that is, the difference between expected and actual costs) from the 1999-2004 regulatory period would be carried forward in to the 2004-09 regulatory period. This negative carryover would reduce the expected rates of return for the DNSPs. A key issue is what impact these lower rates of return would have on incentives for investment. One view of this is that the revenue outcomes under the glide path approach would simply be an outcome of incentive based regulation. If the straight line approach were seen as a form of efficiency carryover that has been and will be applied across past and future regulatory periods, then any disincentive to investment would be reduced. In this situation, the lower returns would reflect the context of a wider picture across a number of regulatory periods whereby the glide path offers expected rates of return that in some periods are higher than the allowed rate of return and in some periods are lower but on average deliver a prospective return on investment equal to the allowed rate of return.

Table A8.1 Summary of approaches

Approach	Price path	Revenue recovery	Incentives for efficiency	Transition to 2009 regulatory period	Consistency with 1999 determination
NPV with single X-factor	Stable price increases in 2004-09	NPV neutral	No additional incentives beyond CPI –X regulation. Lower than straight line/glide path approach, unless intro-ducing ECM[315]	Likely to over-recover final year revenues	Inconsistent with 1999 determination
NPV with P-nought adjustment	Initial price shock followed by stable price increases	NPV neutral	No additional incentives beyond CPI –X regulation. Lower than straight line approach, unless intro-ducing ECM	Could over or under recover final year revenues. Less than single X-factor approach	Inconsistent with 1999 determination
Straight line smoothing	Stable price increases. Likely lowest average price increase in 2004-09	Likely to under-recover in 2004-09 period	Stronger incentives as form of efficiency carryover mechanism	No transition issues	Consistent with 1999 determination
Hybrid straight line smoothing/P-nought approach	Initial price shock (smaller than pure P-nought approach) followed by stable prices	Likely to under-recover in 2004-09 period	Lower incentives than straight line approach but stronger than NPV neutral approaches	No transition issues	Partially consistent with 1999 determination

315 Efficiency carry-over mechanism.

APPENDIX 9 PRICING ISSUES CONSULTATION GROUP (PICG) STAKEHOLDERS REPRESENTED

ORGANISATION	(where two or more meetings were attended)
1	AGL Sales & Marketing
2	Australian Inland
3	BHP Steel
4	Business Council for Sustainable Energy
5	Country Energy
6	Energy & Management Services Consultancy
7	Department of Energy, Utilities and Sustainability (previously known as the Ministry of Energy and Utilities)
8	Energy Action Group
9	EnergyAustralia Network
10	EnergyAustralia Retail
11	Energy Users Association of Australia
12	Energy Reform Forum
13	Essential Services Commission Victoria
14	Energy and Water Ombudsman
15	Integral Energy
16	Independent Pricing and Regulatory Tribunal
17	National Retailers Forum
18	NSW Treasury
19	Origin Energy
20	Public Interest Advocacy Centre
21	Sustainable Energy Development Authority
22	TransGrid

PICG MEETINGS HELD	
1	30 January 2003
2	6 March 2003
3	7 May 2003
4	18 June 2003
5	23 July 2003
6	25 September 2003 (combined with Energy Industry Consultation Group)
7	19 February 2004

APPENDIX 10 NETWORK PRICING PRINCIPLES

1. ***Prices are to be consistent with the form of regulation, including any price limits on network tariffs determined by the Tribunal.***

   A primary function of prices is the recovery of revenues consistent with efficient costs and regulatory objectives. The form of regulation administered by the Tribunal allows for financial viability where operations meet reasonable efficiency targets. For equity reasons the Tribunal also limits the annual change in some prices.

2. ***Prices should be based on a well-defined and clearly explained methodology.***

   Where there is substantial market power, open and transparent pricing practices are essential.

3. ***Price development should incorporate an analysis of the cost of service provision that includes:***
   - ***(a) definition of the classes of service provided and the parameters by which the quantum and standard of service in each class are measured***
   - ***(b) an examination of the cost elements that arise from the use, operation and expansion of the network***
   - ***(c) for each class of service and each cost element, identification of the relationship between the quantum and standard of service provided and the level of current and future cost***
   - ***(d) an allocation of existing and future network costs to service classes***
   - ***(e) the translation of allocated costs into service prices at the defined service standard, and***
   - ***(f) estimates of the range of subsidy-free prices for each service class.***

   The measurement and allocation of costs form the basic building blocks of price development. A range of feasible approaches exist. However, for DNSPs to be able to demonstrate that their prices are soundly based, efficient and transparent, the process of price development must be rigorous and systematic.

4. ***Prices are to signal the economic costs of service provision, by:***
   - ***(a) being subsidy free (greater than incremental costs and less than stand alone costs)***
   - ***(b) having regard to the level of available service capacity, and***
   - ***(c) signalling the impact of additional usage on future investment costs.***

   Prices can influence how customers use the distribution network and how DNSPs operate and maintain it. They can also influence the level of investment undertaken in expanding capacity. Where prices reflect the economic value of the resources used in providing a service, they make an important contribution to economic efficiency and welfare.

   Economic efficiency requires that prices give correct signals for the use, operation and expansion of the network. This encompasses both allocative and dynamic efficiency. These objectives share a common starting point: the efficient, forward-looking costs of meeting additional network loads.

There is considerable debate over the measurement of the upper and lower bounds for the range of subsidy-free prices (ie stand alone cost and incremental cost). The alternative pricing methodology does not mandate a particular methodology. Rather, it allows DNSPs to select the approach they consider most appropriate to their circumstances.

5. ***Where prices based on 'efficient' incremental costs under-recover allowed revenues, the shortfall should be made up in a manner that minimises the effect on consumption and investment while having regard to the impact on users.***

Economic efficiency requires that usage prices recover at least avoidable costs. This can lead to a shortfall in revenue, since for most parts of the network avoidable costs are less than average costs for most of the time ('sunk costs'). In considering revenue make-up options, minimising the impacts on consumption and investment decisions are important criteria.

6. ***Provided that economic costs are covered, prices should be responsive to the requirements and circumstances of users in order to:***
   (a) ***discourage uneconomic bypass, and***
   (b) ***allow negotiation to better reflect the economic value of specific services, including services associated with embedded generation and other options.***

Users may have individual service requirements that vary from the standard form offered. To maximise the economic benefits available from use of the network, an approach to pricing that is responsive to user requirements and circumstances will be required.

7. ***When allocating TUOS charges to distribution network users DNSPs should, to the extent possible, preserve the pricing signals present in the structure of TUOS charges. (Information on allocated TUOS charges should be available to users on request, to the extent possible).***

Network tariffs include an allowance for charges paid by DNSPs for use of the transmission system. DNSPs should have regard to the economic signals present in the structure of TUOS charges when determining the basis for allocating the charges across users of the distribution network.

Users may have an interest in knowing the extent of their contribution to the distributor's TUOS charges. Availability of this price information may lead to more efficient consumption and investment decisions.

8. ***Information on customer class price levels and structures, service standards, underlying costs, price derivation methods and rationale and medium term price and service strategies should be publicly disclosed in order to allow:***
   (a) ***current and potential users to understand the basis for prices and to take account of prices and service standards in their consumption, investment and location decisions***
   (b) ***interested parties to better assess the range of opportunities for meeting user requirements, including through services associated with embedded generation, demand management and other options that may reduce users' costs and lead to more efficient outcomes.***

Access to information is a key factor affecting market efficiency. The availability and transparency of price information is an essential ingredient for sound decision making. Since investment decisions rely on expectations about the future, this applies equally to information on future prices and service levels.

Some network services are potentially open to competition in meeting users' requirements. Where alternative or competing forms of service provision may be available, users should have the opportunity to choose the option with the lowest economic cost.

9. ***Underlying service classifications, cost data, cost allocations and other elements that contribute to pricing decisions should be periodically reviewed and updated where relevant to reflect industry developments and changes in user requirements and preferences, methods of service provision and costs.***

Changes in areas such as metering technology, retail competition, alternative forms of service provision and user preferences can lead to shifts in the nature of efficient network prices. For prices to remain efficient they should reflect such developments.

10. ***Where DNSP price strategies lead to proposed price movements or price restructuring that may be expected to impose significant adjustment costs on users, transitional price options, a phased approach or other measures should be offered to assist in the management of adjustment costs.***

End users make decisions on location, production and investment in electricity-consuming equipment that are influenced by existing prices. Thus substantial or frequent price changes can impose unreasonable or inequitable adjustment costs on them. Such pricing practices can also reduce economic efficiency by increasing the level of uncertainty and risk.

APPENDIX 11 ENERGYAUSTRALIA OPERATING AND FINANCIAL INFORMATION

A11.1 Corporate and operating information

Head Office: 570 George Street Sydney, NSW 2000
Network Service Area: 22,275 square kilometres
Major Towns / Cities: Sydney, Barry, Merriwa, Nelson Bay, Scone, Waterfall
Employee Numbers: 2,738

Source: EnergyAustralia's Price and Service Report 2002.

A11.2 Network demand profile

Table A11.1 Historical demand 1999/00 to 2003/04[1]

	1999/00	2000/01	2001/02	2002/03	2003/04f
Total GWh delivered	24,364	25,276	25,402	25,077	25,595
Peak demand (MW)[2]	4,983	4,696	5,003	5,080	5,165
Total Customers:					
Residential	1,260,714	1,300,446	1,314,973	1,285,596	1,306,244
Non-residential	143,026	144,906	149,305	144,658	147,779

Notes:
1. EnergyAustralia's submission to the 2004 Network Review.
2. Source: Prices and Services Report.

Table A11.2 Forecast demand 2004/05 to 2008/09

	2004/05	2005/06	2006/07	2007/08	2008/09
Total GWh delivered	26,130	26,771	27,236	27,843	28,422
Peak demand (MW)	5,305	5,478	5,635	5,820	6,013
Total Customers:					
Residential	1,324,846	1,347,958	1,365,997	1,390,236	1,413,912
Non-residential	151,495	155,673	158,425	161,873	165,486

Source: MMA Final April 2004.

Table A11.3 Maximum demand

Historical	Winter (MW)	Summer (MW)	Forecast	Winter (MW)	Summer (MW)
1999/00	np	np	2004/05	5,305	5,285
2000/01	np	np	2005/06	5,464	5,478
2001/02	5,003	4,824	2006/07	5,594	5,635
2002/03	5,080	4,950	2007/08	5,750	5,820
2003/04f	5,165	5,112	2008/09	5,911	6,013

Source: Historic: EnergyAustralia's submission to the 2004 Electricity Network Review, Forecast: MMA, Final 2004.

A11.3 Reliability

Table A11.4 Historical reliability

		1999/00	2000/01	2001/02
SAIDI	Raw	90	118	175
	Standard	87	101	102
	MS	84	96	96
SAIFI	Raw	2.3	2.5	2.5
	Standard	1.3	1.2	1.3
	MS	1.2	1.2	1.3
CAIDI	Raw	39	47	69
	Standard	67	80	80
	MS	70	79	77

Source: Network Price and Service Report 2001 and 2002.

Table A11.5 Forecast reliability

		2002/03 A	2003/04 F	2004/05	2005/06	2006/07	2007/08	2008/09
SAIDI	Overall Distn Normalised	102						101
SAIFI	Overall Distn Normalised	1.2	EnergyAustralia chose not to provide information to the definitions requested					1.2
CAIDI	Overall Distn Normalised							

Source: EnergyAustralia's submission to the 2004 Electricity Network Review, April 2003.
Note: Definition of reliability categories changed between 2001/02 and 2002/03.

A11.4 Distribution revenue forecast 2004/05 to 2008/09

Table A11.6 Building block core assumptions

$'000 $ of the year	2004/05	2005/06	2006/07	2007/08	2008/09
Opening RAB [1]	4,115,867	4,439,832	4,761,848	5,082,098	5,392,280
Operating Costs	287,999	303,369	311,932	319,362	325,596
Capital Expenditure	403,276	411,381	420,227	421,398	440,697
Forecast Network Sales (GWh)	26,130	26,771	27,236	27,843	28,422
Forecast Sales Growth (%)	2.1%	2.5%	1.7%	2.2%	2.1%

Note:
1. Opening balance adjusted to exclude transmission assets and street lighting and to include capex over and above what was provided for in the 1999 Determination at its undepreciated value.

Table A11.7 Regulated distribution asset rolled forward from 1998/99 to 2003/04[1]

$'000 $ of year	1998	1999	2000	2001	2002	2003	2004
Total value of assets							
Opening value		3,766,320	3,788,805	3,943,051	4,244,573	4,420,331	4,605,443
Capex/Additions [1]		140,600	256,200	272,300	293,000	293,800	312,192
depreciation		169,693	183,596	207,996	226,210	244,122	261,065
disposals		12,000	11,444	6,127	16,383	5,607	1,970
Indexation		63,579	93,086	243,345	125,350	141,041	142,817
Closing value	**3,766,320**	**3,788,805**	**3,943,051**	**4,244,573**	**4,420,331**	**4,605,443**	**4,797,416**

Notes:

1. Includes transmission assets.
2. Net of capital contributions.

Columns may not add due to rounding.

Table A11.8 Regulated distribution asset rolled forward from 2004/05 to 2008/09

$'000 $ of year	2005	2006	2007	2008	2009
Total RAB					
Opening value	4,797,416	4,439,832	4,761,848	5,082,098	5,392,280
Adustment [1]	-681,549	0	0	0	0
Indexation	107,820	116,020	124,181	132,202	140,198
Capex/Additions [2]	403,276	411,381	420,227	421,398	440,697
depreciation	177,707	195,962	214,735	233,996	254,107
disposals	9,423	9,423	9,423	9,423	9,423
Closing value	**4,439,832**	**4,761,848**	**5,082,098**	**5,392,280**	**5,709,645**

Notes:

1. In the 1999 determination, EnergyAustralia's regulatory asset base was presented including transmission assets (which are regulated by the ACCC). This determination does not include transmission assets in the distribution regulatory asset base. In addition, street lighting assets are an excluded distribution service, so these assets are also deducted from the regulatory asset base. The capex over and above what was provided for in the 1999 determination has been included at its undepreciated value.
2. Net of capital contributions.
3. Depreciation included in the building blocks calculated for the revenue requirement differs from the depreciation calculated for the asset base due to timing differences. Depreciation included in the building blocks is calculated in the middle of the year whereas depreciation for the asset base is calculated at the end of the year.

Columns may not add due to rounding.

A11.5 Notional and smoothed revenue requirements

Table A11.9 Notional and smoothed revenue requirement 2004/05 to 2008/09

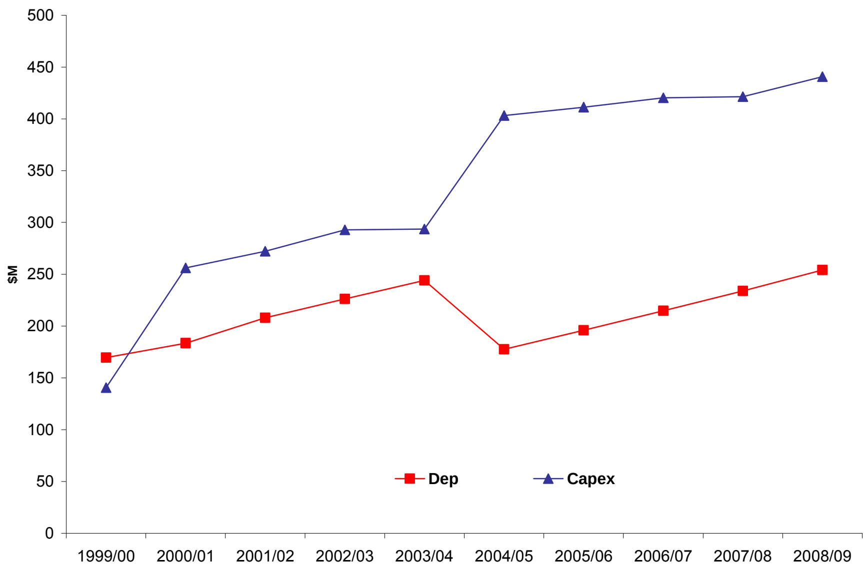
Financial year ending 30 June	2005	2006	2007	2008	2009
$'000 $ of the year					
Operating expenditure	287,999	303,369	311,932	319,362	325,596
Depreciation	169,688	187,119	205,045	223,437	242,640
Return on fixed assets	295,479	317,952	340,317	362,299	384,211
Return on working capital	6,491	6,130	6,140	6,630	7,173
Building Block Revenue	**759,657**	**814,570**	**863,435**	**911,727**	**959,620**
less correction for previous over/under recovery	20,778	22,788	24,993	27,411	30,063
Unsmoothed Revenue	**738,879**	**791,782**	**838,442**	**884,317**	**929,557**
Smoothed Revenue	**729,762**	**772,052**	**818,590**	**872,908**	**928,694**
Return on capital (real pre-tax)	**6.8%**	**6.6%**	**6.6%**	**6.8%**	**7.0%**
NPV of revenue foregone	**50,469**				

Notes:

1. Depreciation included in the building blocks calculated for the revenue requirement differs from the depreciation calculated for the asset base due to timing differences. Depreciation included in the building blocks is calculated in the middle of the year whereas depreciation for the asset base is calculated at the end of the year.
2. The difference between forecast unsmoothed and smoothed revenue in 2009 is due to the X-factor being rounded to one decimal place.

Columns may not add due to rounding.

Figure A11.1 Return of capital (depreciation) versus capex profile



A11.6 Financial performance ratios

Table A11.10 Financial Ratio Analysis – Actual Gearing

	2005	2006	2007	2008	2009
Ability to service debt					
- EBITDA / interest expense	3.48	3.41	3.41	3.48	3.59
NSW Treasury rating (2002)	**A+**	**A+**	**A+**	**A+**	**AA**
- Funds flow interest cover	3.66	3.59	3.52	3.58	3.69
S&P - US Utilities (1995)	**A**	**A**	**A**	**A**	**A**
Ability to repay debt					
- Funds flow net debt payback	**7.89**	**7.82**	**7.71**	**7.39**	**7.05**
NSW Treasury rating (2002)	BBB	BBB	BBB	BBB	BBB
- Debt to equity ratio	**47%**	**47%**	**47%**	**47%**	**47%**
NSW Treasury rating (2002)	**A+**	**A**	**A**	**A**	**A+**
S&P - US Utilities (1995)	AA	A	A	A	AA
Ability to finance investment from internal sources					
- Internal financing ratio	0.51	0.55	0.58	0.64	0.66
NSW Treasury rating (2002)	BBB	BBB	BBB	BBB+	BBB+
NSW Treasury total score (0 - 10)					
- Total Debt/ (Debt + Equity)	**7.00**	**6.00**	**6.00**	**6.00**	**7.00**
Internal financing ratio	4.00	4.00	4.00	5.00	5.00
Total score	**5.00**	**5.00**	**5.00**	**5.33**	**5.67**
Overall rating	**BBB+**	**BBB+**	**BBB+**	**BBB+**	**BBB+**
Net Debt $m	**2,117**	**2,282**	**2,438**	**2,570**	**2,694**

Notes:

1. Weightings for NSW Treasury Score: 33 per cent EBITDA interest cover, funds flow and internal financing ratio.

Table A11.11 Financial Ratio Analysis – Notional 60% gearing

	2005	2006	2007	2008	2009
Ability to service debt					
- EBITDA / interest expense	2.67	2.66	2.69	2.78	2.89
NSW Treasury rating (2002)	**BBB+**	**BBB+**	**BBB+**	**BBB+**	**BBB+**
- Funds flow interest cover	2.81	2.80	2.78	2.86	2.97
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
Ability to repay debt					
- Funds flow net debt payback	**11.08**	**10.88**	**10.54**	**9.96**	**9.37**
NSW Treasury rating (2002)	BB	BB	BB	BB	BB
- Debt to equity ratio	**60.0%**	**59.7%**	**59.1%**	**58.3%**	**57.3%**
NSW Treasury rating (2002)	**BB**	**BB+**	**BB+**	**BB+**	**BBB**
S&P - US Utilities (1995)	BB	BB	BB	BBB	BBB
Ability to finance investment from internal sources					
- Internal financing ratio	0.49	0.53	0.56	0.62	0.64
NSW Treasury rating (2002)	BB+	BBB	BBB	BBB+	BBB+
NSW Treasury total score (0 - 10)					
- Total Debt/ (Debt + Equity)	**2.00**	**3.00**	**3.00**	**3.00**	**4.00**
Internal financing ratio	3.00	4.00	4.00	5.00	5.00
Total score	**3.33**	**3.67**	**3.67**	**4.00**	**4.00**
Overall rating	**BB+**	**BB+**	**BB+**	**BBB**	**BBB**
Net Debt $m	**2,707**	**2,879**	**3,045**	**3,185**	**3,318**

Notes:

1. Weightings for NSW Treasury Score: 33 per cent EBIT DA interest cover, funds flow and internal financing ratio.

A11.7 Distribution financial performance statement

Table A11.12 Distribution financial performance statement

$'000 $ of year	2005	2006	2007	2008	2009
Total revenue	**892,641**	**945,783**	**1,003,899**	**1,070,567**	**1,139,528**
Total costs	**450,878**	**477,100**	**497,240**	**517,021**	**536,430**
EBITDA	**441,763**	**468,684**	**506,658**	**553,546**	**603,098**
EBIT	**264,056**	**272,722**	**291,923**	**319,550**	**348,991**
Profit before tax	**138,703**	**136,901**	**145,220**	**162,514**	**183,264**
Profit after tax	97,092	95,831	101,654	113,760	128,285

Columns may not add due to rounding.

A11.8 Summary of the roll forward of RAB

Table A11.13 Forecast roll forward of RAB

$'000 $ of the year	2005	2006	2007	2008	2009
Total system assets					
Opening value	3,840,478	4,155,821	4,474,763	4,799,404	5,118,004
Capex/Additions	362,687	369,965	379,663	377,886	396,097
depreciation	144,902	156,556	168,650	181,008	193,709
disposals	2,950	2,950	2,950	2,950	2,950
Indexation	100,509	108,483	116,578	124,672	132,864
Closing value	**4,155,821**	**4,474,763**	**4,799,404**	**5,118,004**	**5,450,307**
Total non-system assets					
Opening value	275,388	284,011	287,085	282,694	274,275
Capex/Additions	40,589	41,416	40,564	43,512	44,600
depreciation	32,805	39,406	46,085	52,989	60,398
disposals	6,473	6,473	6,473	6,473	6,473
Indexation	7,311	7,537	7,603	7,530	7,333
Closing value	**284,011**	**287,085**	**282,694**	**274,275**	**259,338**
Total RAB					
Opening value	4,115,867	4,439,832	4,761,848	5,082,098	5,392,280
Capex/Additions	403,276	411,381	420,227	421,398	440,697
depreciation	177,707	195,962	214,735	233,996	254,107
disposals	9,423	9,423	9,423	9,423	9,423
Indexation	107,820	116,020	124,181	132,202	140,198
Closing value	**4,439,832**	**4,761,848**	**5,082,098**	**5,392,280**	**5,709,645**

Notes:
All capex / additions are net of capital contributions.
Columns may not add due to rounding.

APPENDIX 12 INTEGRAL ENERGY OPERATING AND FINANCIAL INFORMATION

A12.1 Corporate and operating information

Head Office: 51 Huntingwood Drive Huntingwood, NSW 2148
Network Service Area: 24,500 square kilometres
Major Towns / Cities: Blacktown, Campbelltown, Liverpool, Parramatta, Penrith, Wollongong
Employee Numbers: 1,353

Source: Integral Energy's submission to IPART, 10 April 2003 and Price and Service Report 2002.

A12.2 Network demand profile

Table A12.1 Historical demand 1999/00 to 2003/04

	1999/00	2000/01	2001/02	2002/03	2003/04f
Total GWh delivered[1]	12,784	13,890	13,864	16,486	17,030
Peak demand (MW)[1]	2,858	2,966	2,994	3,114	3,246
Total Customers:					
Residential	679,445	691,561	705,950	716,280	729,574
Non-residential	63,711	69,387	70,371	71,380	73,693

1. Source: Prices and Services Report 2002, includes CRNP customers.

Table A12.2 Forecast demand 2004/05 to 2008/09

	2004/05	2005/06	2006/07	2007/08	2008/09
Total GWh delivered [1]	17,376	17,796	18,091	18,483	18,860
Peak demand (MW)	3,350	3,466	3,560	3,671	3,786
Total Customers:					
Residential	743,115	756,909	770,957	785,266	799,841
Non-residential	75,610	77,756	79,212	81,010	82,893

1. Includes CRNP customers.

Table A12.3 Maximum demand

Historical	Winter (MW)	Summer (MW)	Forecast	Winter (MW)	Summer (MW)
1999/00	-	-	2004/05	3,264	3,350
2000/01	-	-	2005/06	3,360	3,466
2001/02	2,555	2,994	2006/07	3,437	3,560
2002/03	2,672	3,114	2007/08	3,531	3,671
2003/04f	3,180	3,246	2008/09	3,627	3,786

Source: Historic: Integral Energy, *Prices and Service Report 2002*, Forecast: MMA.

A12.3 Reliability

Table A12.4 Historical reliability

		1999/00	2000/01	2001/02
SAIDI	Raw	124	217	737
	Standard	124	136	134
	MS	84	96	99
SAIFI	Raw	2.13	2.95	3.43
	Standard	1.23	1.30	1.26
	MS	1.11	1.16	1.14
CAIDI	Raw	58	74	215
	Standard	101	105	107
	MS	75	83	87

Source: Draft Electricity Network Performance Report 2002/03.

Table A12.5 Forecast reliability

		2002/03a	2003/04f	2004/05	2005/06	2006/07	2007/08	2008/09
SAIDI	Overall	217	np	374	354	338	318	302
	Distn	155	np	366	346	329	310	295
	Normalised	120	119	114	108	103	97	92
SAIFI	Overall	2.74	np	2.91	2.76	2.63	2.48	2.35
	Distn	1.42	np	2.85	2.71	2.58	2.42	2.30
	Normalised	1.3	np	1.21	1.15	1.09	1.02	0.97
CAIDI	Overall	79	np	128	128	128	128	128
	Distn	109	np	np	np	np	np	np
	Normalised	92	np	94	94	94	94	94

Source: Integral Energy's submission to the 2004 Electricity Network Review, September 2003.
Note: Definition of reliability categories changed between 2001/02 and 2002/03.
np = numbers not currently available.

A12.4 Distribution revenue forecast 2004/05 to 2008/09

Table A12.6 Building block core assumptions

$'000 $ of the year	2004/05	2005/06	2006/07	2007/08	2008/09
Opening RAB [1]	2,283,456	2,492,752	2,711,579	2,898,945	3,085,922
Operating Costs	208,337	213,666	221,194	228,844	236,381
Capital Expenditure	285,251	303,766	281,578	290,866	257,970
Forecast Network Sales (GWh)	17,376	17,796	18,091	18,483	18,860
Forecast Sales Growth (%)	2.0%	2.4%	1.7%	2.2%	2.0%

1. Opening balance adjusted to exclude street lighting and to include capex over and above what was provided for in the 1999 Determination at its undepreciated value.

Table A12.7 Regulated distribution asset rolled forward from 1998/99 to 2003/04

$'000 $ of year	1998	1999	2000	2001	2002	2003	2004
Total value of assets							
Opening value		1,731,735	1,761,115	1,782,320	1,863,940	1,941,346	2,019,338
Capex/Additions [1]		98,265	98,406	96,679	146,587	147,793	271,736
depreciation		94,409	104,687	115,199	124,561	131,834	139,898
disposals		4,000	15,417	8,885	24	235	-
Indexation		29,525	42,902	109,025	55,405	62,267	64,656
Closing value	**1,731,735**	**1,761,115**	**1,782,320**	**1,863,940**	**1,941,346**	**2,019,338**	**2,215,831**

Note:

1. Net of capital contributions.

Columns may not add due to rounding.

Table A12.8 Regulated distribution asset rolled forward from 2004/05 to 2008/09

$'000 $ of year	2005	2006	2007	2008	2009
Total RAB					
Opening value	2,215,831	2,492,752	2,711,579	2,898,945	3,085,922
Adustment[1]	67,625	0	0	0	0
Indexation	60,649	66,113	71,306	76,106	80,369
Capex/Additions[2]	285,251	303,766	281,578	290,866	257,970
depreciation	136,355	150,797	165,258	179,728	194,530
disposals	249	255	261	268	274
Closing value	**2,492,752**	**2,711,579**	**2,898,945**	**3,085,922**	**3,229,457**

Notes:

1. Street lighting is an excluded distribution service. Capex over and above what was provided for in the 1999 determination has been included at its undepreciated value.
2. Depreciation included in the building blocks calculated for the revenue requirement differs from the depreciation calculated for the asset base due to timing differences. Depreciation included in the building blocks is calculated in the middle of the year whereas depreciation for the asset base is calculated at the end of the year.
3. Net of capital contributions.

Columns may not add due to rounding.

A12.5 Notional and smoothed revenue requirements

Table A12.9 Notional and smoothed revenue requirement 2004/05 to 2008/09

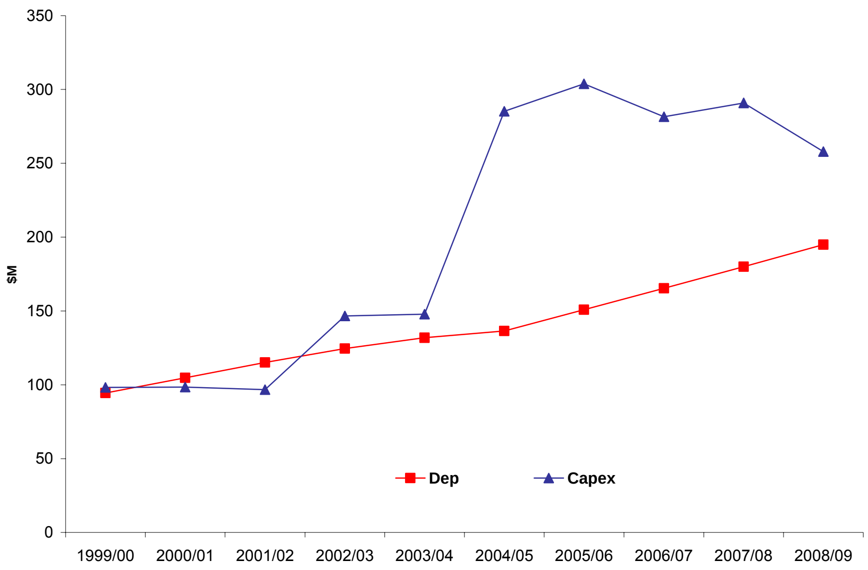
Financial year ending 30 June	2005	2006	2007	2008	2009
$'000 $ of the year					
Operating expenditure	208,337	213,666	221,194	228,844	236,381
Depreciation	130,202	143,992	157,800	171,617	185,751
Return on fixed assets	166,208	181,181	195,413	208,568	220,251
Return on working capital	2,518	2,703	2,976	3,417	3,831
Building Block Revenue	**507,264**	**541,543**	**577,383**	**612,446**	**646,214**
less correction for previous over/under recovery	15,290	16,769	18,392	20,171	22,123
Unsmoothed Revenue	**491,975**	**524,773**	**558,992**	**592,275**	**624,092**
Smoothed Revenue	**487,162**	**519,161**	**550,195**	**586,181**	**622,971**
Return on capital (real pre-tax)	**6.8%**	**6.8%**	**6.7%**	**6.8%**	**7.0%**
NPV of revenue foregone	**21,615**				

Notes:

1. Depreciation included in the building blocks calculated for the revenue requirement differs from the depreciation calculated for the asset base due to timing differences. Depreciation included in the building blocks is calculated in the middle of the year whereas depreciation for the asset base is calculated at the end of the year.
2. The difference between forecast unsmoothed and smoothed revenue in 2009 is due to the X-factor being rounded to one decimal place.

Columns may not add due to rounding.

Figure A12.1 Return of capital (depreciation) Versus capex profile



A12.6 Financial performance ratios

Table A12.10 Financial Ratio Analysis – Actual Gearing

	2005	2006	2007	2008	2009
Ability to service debt					
- EBITDA / interest expense	3.77	3.85	3.52	3.58	3.56
NSW Treasury rating (2002)	**AA**	**AA**	**AA**	**AA**	**AA**
- Funds flow interest cover	3.78	3.93	3.50	3.61	3.56
S&P - US Utilities (1995)	**A**	**A**	**A**	**A**	**A**
Ability to repay debt					
- Funds flow net debt payback	**6.48**	**6.56**	**6.76**	**6.55**	**6.26**
NSW Treasury rating (2002)	BBB+	BBB+	BBB+	BBB+	BBB+
- Debt to equity ratio	**49%**	**50%**	**50%**	**50%**	**49%**
NSW Treasury rating (2002)	**A**	**A**	**A**	**A**	**A**
S&P - US Utilities (1995)	A	A	A	A	A
Ability to finance investment from internal sources					
- Internal financing ratio	0.53	0.55	0.64	0.68	0.83
NSW Treasury rating (2002)	BBB	BBB	BBB+	BBB+	AA
NSW Treasury total score (0 - 10)					
- Total Debt/ (Debt + Equity)	**4.00**	**4.00**	**4.00**	**4.00**	**5.00**
Internal financing ratio	4.00	4.00	5.00	5.00	8.00
Total score	**5.67**	**6.00**	**6.00**	**6.00**	**7.00**
Overall rating	**BBB+**	**A**	**A**	**A**	**A+**
Net Debt $m	**1,235**	**1,367**	**1,476**	**1,568**	**1,616**

Notes:

1. Weightings for NSW Treasury Score: 33 per cent EBITDA interest cover, funds flow and internal financing ratio.

Table A12.11 Financial Ratio Analysis – Notional 60% Gearing

	2005	2006	2007	2008	2009
Ability to service debt					
- EBITDA / interest expense	3.02	3.13	2.94	3.02	3.03
NSW Treasury rating (2002)	**A**	**A**	**BBB+**	**A**	**A**
- Funds flow interest cover	3.03	3.19	2.92	3.04	3.03
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
Ability to repay debt					
- Funds flow net debt payback	**8.48**	**8.43**	**8.58**	**8.22**	**7.81**
NSW Treasury rating (2002)	BB+	BB+	BB+	BB+	BBB
- Debt to equity ratio	**60.0%**	**60.2%**	**60.1%**	**59.5%**	**58.3%**
NSW Treasury rating (2002)	**BB+**	**BB**	**BB**	**BB+**	**BB+**
S&P - US Utilities (1995)	BB	BB	BB	BB	BBB
Ability to finance investment from internal sources					
- Internal financing ratio	0.52	0.54	0.63	0.67	0.81
NSW Treasury rating (2002)	BBB	BBB	BBB+	BBB+	AA
NSW Treasury total score (0 - 10)					
- Total Debt/ (Debt + Equity)	**3.00**	**2.00**	**2.00**	**3.00**	**3.00**
Internal financing ratio	4.00	4.00	5.00	5.00	8.00
Total score	**4.33**	**4.33**	**4.33**	**4.67**	**6.00**
Overall rating	**BBB**	**BBB**	**BBB**	**BBB**	**A**
Net Debt $m	**1,513**	**1,649**	**1,763**	**1,858**	**1,910**

Notes:

1. Weightings for NSW Treasury Score: 33 per cent EBITDA interest cover, funds flow and internal financing ratio.

A12.7 Distribution financial performance statement

Table A12.12 Distribution financial performance statement

$'000 $ of year	2005	2006	2007	2008	2009
Total revenue	**583,202**	**630,872**	**665,047**	**703,559**	**744,423**
Total costs	**302,540**	**324,106**	**334,755**	**344,917**	**356,511**
EBITDA	**280,662**	**306,767**	**330,292**	**358,642**	**387,912**
EBIT	**144,307**	**155,970**	**165,034**	**178,915**	**193,382**

Columns may not add due to rounding.

A12.8 Summary of rolled forward RAB

Table A12.13 Summary of rolled forward RAB

$'000 $ of the year	2005	2006	2007	2008	2009
Total system assets					
Opening value	2,021,657	2,213,835	2,434,709	2,635,703	2,840,427
Capex/Additions	240,424	273,358	257,953	266,536	230,468
depreciation	101,788	111,242	121,045	131,032	141,075
disposals	5	5	5	5	5
Indexation	53,547	58,763	64,092	69,224	73,891
Closing value	**2,213,835**	**2,434,709**	**2,635,703**	**2,840,427**	**3,003,705**
Total non-system assets					
Opening value	261,799	278,918	276,871	263,242	245,496
Capex/Additions	44,827	30,408	23,626	24,330	27,502
depreciation	34,567	39,555	44,212	48,695	53,454
disposals	244	250	256	263	269
Indexation	7,102	7,350	7,214	6,882	6,478
Closing value	**278,918**	**276,871**	**263,242**	**245,496**	**225,752**
Total RAB					
Opening value	2,283,456	2,492,752	2,711,579	2,898,945	3,085,922
Capex/Additions	285,251	303,766	281,578	290,866	257,970
depreciation	136,355	150,797	165,258	179,728	194,530
disposals	249	255	261	268	274
Indexation	60,649	66,113	71,306	76,106	80,369
Closing value	**2,492,752**	**2,711,579**	**2,898,945**	**3,085,922**	**3,229,457**

Notes:
All capex / additions are net of capital contributions.
Columns may not add due to rounding.

APPENDIX 13 COUNTRY ENERGY OPERATING AND FINANCIAL INFORMATION

A13.1 Corporate and operating information

Head Office: Cnr Littlebourne Street and Hampden Park Road, Kelso NSW 2795
Network Service Area: 582,000 square kilometres
Major Towns / Cities: Albury, Bathurst, Dubbo, Grafton, Port Macquarie, Queanbeyan, Tamworth, Wagga Wagga
Employee Numbers: 2,345

Sources: Country Energy submission to 2004 Distribution Review, April 2003 and Country Energy, 2003 Annual Report.

A13.2 Network demand profile

Table A13.1 Historical demand 1999/00 to 2003/04

	1999/00	2000/01	2001/02	2002/03	2003/04f
Total GWh delivered	9,648[1]	10,007	9,965	10,387	10,650
Peak demand (MW)[1]	np	1,950	1,909	2,021	2,082
Total Customers:	716,578[1]				
Residential		595,675	628,422	566,165	574,446
Non-residential		110,865	87,808	145,999	146,939

Source: Country Energy Prices and Services Report 2002.
Note 1: Includes North Power, Great Southern Energy and Advance Energy. np means not provided.

Table A13.2 Forecast demand 2004/05 to 2008/09

	2004/05	2005/06	2006/07	2007/08	2008/09
Total GWh delivered	10,838	11,071	11,269	11,455	11,610
Peak demand (MW)	2,097	2,154	2,205	2,255	2,300
Total customers					
Residential	584,653	595,878	606,159	615,973	625,601
Non residential	150,982	155,517	158,516	162,288	166,283

Source: IPART Financial Model and MMA, Final April 2004.

Table A13.3 Maximum demand

Historical	Winter (MW)	Summer (MW)	Forecast	Winter (MW)	Summer (MW)
1999/00	np	np	2004/05	2,097	1,735
2000/01	1,820	1,659	2005/06	2,154	1,798
2001/02	1,909	1,549	2006/07	2,205	1,842
2002/03	1,992	1,629	2007/08	2,255	1,893
2003/04f	2,049	1,687	2008/09	2,300	1,939

Source: Historic: Country Energy submission to the 2004 Network Review, Forecast: MMA, Final 2004.

A13.3 Reliability

Table A13.4 Historical reliability

		1999/00	2000/01	2001/02
SAIDI	Raw	169	242	178
	Standard	np	173	167
	MS	131	138	137
SAIFI	Raw	np	2.0	1.9
	Standard	np	1.5	1.5
	MS	1.4	1.3	1.4
CAIDI	Raw	np	121	95
	Standard	np	116	109
	MS	91	110	98

Source: MoEU, *Electricity Network Performance Report* 2002/03. 'np' means not provided.

Table A13.5 Forecast reliability

		2002/03a	2003/04f	2004/05	2005/06	2006/07	2007/08	2008/09
SAIDI	Overall	308	336	403	484	484	474	465
	Distn	287	313	376	451	451	442	433
	Normalised	230	251	301	361	361	354	347
SAIFI	Overall	2.72	2.97	3.56	4.27	4.27	4.19	4.11
	Distn	2.39	2.61	3.13	3.76	3.76	3.68	3.61
	Normalised	2.16	2.36	2.83	3.39	3.39	3.33	3.26
CAIDI	Overall	113	113	113	113	113	113	113
	Distn	120	120	120	120	120	120	120
	Normalised	106	106	106	106	106	106	106

Source: Country Energy submission to the 2004 Electricity Network Review, September 2003.
Note: Definition of reliability categories changed between 2001/02 and 2002/03.

A13.4 Distribution revenue forecast 2004/05 to 2008/09

Table A13.6 Building block core assumptions

$'000 $ of the year	2004/05	2005/06	2006/07	2007/08	2008/09
Opening RAB[1]	2,374,614	2,530,818	2,689,488	2,850,026	3,019,583
Operating Costs	222,499	231,131	240,095	249,408	259,080
Capital Expenditure	239,527	244,689	248,021	257,287	263,762
Forecast Network Sales (GWh)	10,838	11,071	11,269	11,455	11,610
Forecast Sales Growth (%)	1.8%	2.1%	1.8%	1.7%	1.3%

Note:
1. Opening balance adjusted to exclude street lighting and to include capex over and above what was provided for in the 1999 Determination at its undepreciated value.

Table A13.7 Regulated distribution asset rolled forward from 1998/99 to 2003/04

$'000 $ of year	1998	1999	2000	2001	2002	2003	2004f
Opening value		1,675,524	1,743,885	1,776,365	1,921,766	2,041,891	2,197,220
Capex/Additions[1]		146,956	123,762	141,609	180,999	220,983	228,872
Depreciation		89,422	93,350	101,925	110,970	122,747	135,556
Disposals		18,053	40,428	4,427	7,350	9,272	9,550
Indexation		28,879	42,496	110,144	57,446	66,365	69,206
Closing value	**1,675,524**	**1,743,885**	**1,776,365**	**1,921,766**	**2,041,891**	**2,197,220**	**2,350,192**

Notes:
1. Net of capital contributions.
2. Columns may not add due to rounding.

Table A13.8 Regulated distribution asset rolled forward from 2004/05 to 2008/09

$'000 $ of year	2005	2006	2007	2008	2009
Opening value of fixed assets	2,350,192	2,530,818	2,689,488	2,850,026	3,019,583
Adjustment to opening value	24,422	-	-	-	-
Indexation	62,266	66,235	70,244	74,373	78,693
Capex/Additions (net of cap cons)	239,527	244,689	248,021	257,287	263,762
depreciation before deferral	138,089	154,347	170,914	188,040	205,879
deferred depreciation	-	9,593	20,687	33,437	47,960
disposals	7,500	7,500	7,500	7,500	7,500
Closing value of fixed assets	**2,530,818**	**2,689,488**	**2,850,026**	**3,019,583**	**3,196,619**

Notes
1. Street lighting is an excluded distribution service. Capex over and above what was provided for in the 1999 determination has been included at its undepreciated value.
2. Depreciation included in the building blocks calculated for the revenue requirement differs from the depreciation calculated for the asset base due to timing differences. Depreciation included in the building blocks is calculated in the middle of the year whereas depreciation for the asset base is calculated at the end of the year.
3. Net of capital contributions.

Columns may not add due to rounding.

A13.5 Smoothed revenue requirements

Table A13.9 Smoothed revenue requirement 2004/05 to 2008/09

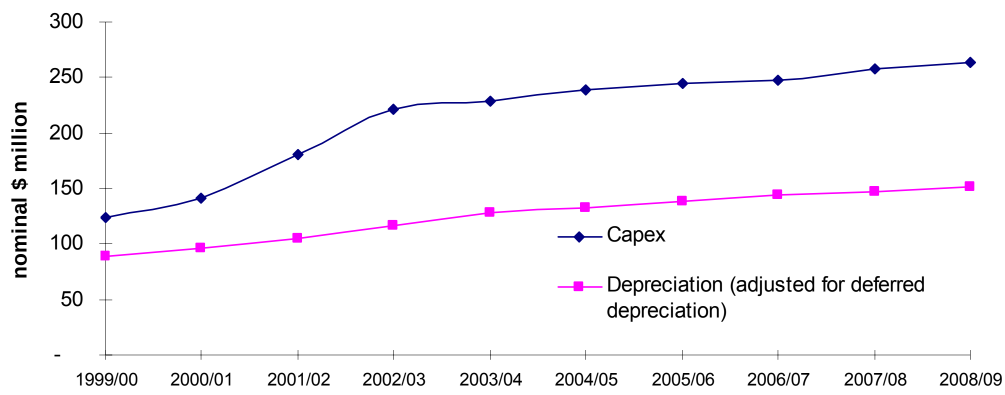
Country Energy	2004/05	2005/06	2006/07	2007/08	2008/09
$'000 $ of year					
Operating expenditure	222	231	240	249	259
Return of capital (depreciation)	132	138	143	148	151
Return on capital	123	142	163	186	212
Return on working capital	4	4	4	5	5
Less correction of previous under/over recovery balance	-0	-0	-0	-0	-1
Smoothed revenue requirements	**481**	**516**	**551**	**588**	**627**
Rate of return	**5.0%**	**5.5%**	**5.9%**	**6.4%**	**6.9%**

Notes:

1. Depreciation included in the building blocks calculated for the revenue requirement differs from the depreciation calculated for the asset base due to timing differences. Depreciation included in the building blocks is calculated in the middle of the year whereas depreciation for the asset base is calculated at the end of the year.
2. Depreciation is after deferral (see chapte 7).

Columns may not add due to rounding.

Figure A13.1 Return of capital (depreciation) versus capex profile



A13.6 Financial performance ratios

Table A13.10 Financial analysis – actual gearing

	2005	2006	2007	2008	2009
Ability to service debt					
- EBITDA / interest expense	2.89	3.00	3.11	3.25	3.42
NSW Treasury rating (2002)	**BBB+**	**BBB+**	**A**	**A+**	**A+**
- Funds flow interest cover	2.94	3.04	3.14	3.29	3.45
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**A**	**A**
Ability to repay debt					
- Funds flow net debt payback	8.93	8.44	7.92	7.37	6.82
NSW Treasury rating (2002)	**BB+**	**BB+**	**BBB**	**BBB**	**BBB+**
- (Debt-cash assets)/(RAB)	0.56	0.55	0.54	0.53	0.51
NSW Treasury rating (2002)	**BBB**	**BBB**	**BBB+**	**BBB+**	**BBB+**
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**A**
Ability to finance investment from internal sources					
- Internal financing ratio	0.60	0.66	0.72	0.77	0.82
NSW Treasury rating (2002)	**BBB+**	**BBB+**	**A**	**A+**	**AA**
NSW Treasury total score (0 - 10)					
- EBITDA + interest earnings / interest expense	5.00	5.00	6.00	7.00	7.00
- Funds flow net debt payback	3.00	3.00	4.00	4.00	5.00
-Total Debt/ (Debt + Equity)	5.00	5.00	5.00	5.00	5.00
Internal financing ratio	5.00	5.00	6.00	7.00	8.00
Total score	**4.33**	**4.33**	**5.33**	**6.00**	**6.67**
Overall rating	**BBB**	**BBB**	**BBB+**	**A**	**A**
Net Debt $m	**1,439**	**1,515**	**1,578**	**1,630**	**1,669**

Notes:

1.Tax and dividend payments, cash flows and ratios have been calculated using regulatory depreciation before deferral.

2. In calculating the NSW Treasury total score, equal weigh is applied to the EBITDA interest cover, funds flow net debt payback and internal financing ratio.

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Table A13.11 Financial analysis – notional 60% gearing

	2005	2006	2007	2008	2009
Ability to service debt					
- EBITDA / interest expense	2.68	2.80	2.91	3.05	3.21
NSW Treasury rating (2002)	**BBB+**	**BBB+**	**BBB+**	**A**	**A**
- Funds flow interest cover	2.73	2.83	2.94	3.08	3.23
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
Ability to repay debt					
- Funds flow net debt payback	9.86	9.28	8.67	8.04	7.43
NSW Treasury rating (2002)	**BB**	**BB**	**BB+**	**BB+**	**BBB**
- (Debt-cash assets)/(RAB)	60%	59%	58%	57%	55%
NSW Treasury rating (2002)	**BB+**	**BB+**	**BB+**	**BBB**	**BBB+**
S&P - US Utilities (1995)	**BB**	**BB**	**BBB**	**BBB**	**BBB**
Ability to finance investment from internal sources					
- Internal financing ratio	0.60	0.66	0.72	0.76	0.82
NSW Treasury rating (2002)	**BBB**	**BBB+**	**A**	**A+**	**AA**
NSW Treasury total score (0 - 10)					
- EBITDA + interest earnings / interest expense	5.00	5.00	5.00	6.00	6.00
- Funds flow net debt payback	2.00	2.00	3.00	3.00	4.00
-Total Debt/ (Debt + Equity)	3.00	3.00	3.00	4.00	5.00
Internal financing ratio	4.00	5.00	6.00	7.00	8.00
Total score	**3.67**	**4.00**	**4.67**	**5.33**	**6.00**
Overall rating	**BB+**	**BBB**	**BBB**	**BBB+**	**A**
Net Debt $m	**1,544**	**1,622**	**1,686**	**1,739**	**1,780**

Notes:
1.Tax and dividend payments, cash flows and ratios have been calculated using regulatory depreciation before deferral.
2. In calculating the NSW Treasury total score, equal weigh is applied to the ratios EBITDA interest cover, funds flow net debt payback and internal financing ratio.

A13.7 Distribution financial performance statement

Table A13.12 Distribution financial performance statement

$'000 $ of year	2005	2006	2007	2008	2009
Total revenue	599,337	641,161	684,087	729,858	777,369
Total costs	340,374	356,349	373,031	390,848	409,309
EBITDA (Earnings before interest, tax, depreciation)	258,963	284,812	311,055	339,011	368,060
Depreciation of RAB	138,089	154,347	170,914	188,040	205,879
EBIT (Earning before interest and tax)	120,874	130,465	140,141	150,971	162,181

Note:
1. Depreciation is pre-deferral.
Columns may not add due to rounding.

APPENDIX 14 AUSTRALIAN INLAND OPERATING AND FINANCIAL INFORMATION

A14.1 Corporate and operating information

Head Office: 160-162 Beryl Street, Broken Hill, NSW 2880
Network Service Area: 155,000 square kilometres
Major Towns / Areas: Area from the Queensland to Victorian borders, South Australian border in the west to White Cliffs, Wilcannia, Balranald and Moulamein in the east
Employee Numbers: 74

Source : Australian Inland's submission to IPART, 10 April 2003, *Price and Service Report 2002,* and 2002 Annual Report and website.

A14.2 Network demand profile

Table A14.1 Historical demand 1999/00 to 2003/04

	1999/00	2000/01	2001/02	2002/03	2003/04f
Total GWh delivered	409	415	402	260	273
Peak demand (MW)[1]	57	59	59	60	61
Total Customers:					
Residential	15,473	15,469	15,511	15,534	15,556
Non-residential	3,389	3,400	3,396	5,940	6,206

Source: 1 Australian Inland Prices and Services Report 2002. Includes CRNP customers.

Table A14.2 Forecast demand 2004/05 to 2008/09

	2004/05	2005/06	2006/07	2007/08	2008/09
Total GWh delivered	278	284	290	295	301
Peak demand (MW)	62	63	64	np	np
Total Customers:					
Residential	15,578	15,600	15,623	15,645	15,667
Non-residential	6,289	6,387	6,451	6,529	6,605

Source: IPART Financial Model and MMA, Final April 2004.

Table A14.3 Maximum demand

Historical	Winter (MW)	Summer (MW)	Forecast	Winter (MW)	Summer (MW)
1999/00	np	np	2004/05	np	np
2000/01	np	np	2005/06	np	np
2001/02	np	np	2006/07	np	np
2002/03	np	np	2007/08	np	np
2003/04f	np	np	2008/09	np	np

Source: Historic: Australian Inland submission to the 2004 Network Review, Forecast: .MMA, Final April 2004.
np = not provided.

A14.3 Reliability

Table A14.4 Historical reliability

		1999/00	2000/01	2001/02
SAIDI	Raw	203	364	359
	Standard	203	351	354
	MS	140	246	269
SAIFI	Raw	3.2	3.3	2.8
	Standard	3.2	3.1	2.8
	MS	2.9	2.7	2.3
CAIDI	Raw	64	108	126
	Standard	64	113	128
	MS	49	91	115

Source: Network Price and Service Report 2002

Table A14.5 Forecast reliability

		2002/03a	2003/04f	2004/05	2005/06	2006/07	2007/08	2008/09
SAIDI	Overall	336	320	303	303	295	295	295
	Distn	274	292	275	275	267	267	267
	Normalised	157	175	158	158	150	150	150
SAIFI	Overall	2.9	1.8	1.7	1.7	1.5	1.5	1.5
	Distn	2.0	1.8	1.6	1.6	1.5	1.5	1.5
	Normalised	1.6	1.4	1.3	1.3	1.1	1.1	1.1
CAIDI	Overall	116	178	182	182	195	195	195
	Distn	137	165	168	168	180	180	180
	Normalised	98	126	126	120	136	136	136

Source: Australian Inland's submission to the 2004 Electricity Network Review, September 2003.
Note: Definition of reliability categories changed between 2001/02 and 2002/03.
np = numbers not currently available.

A14.4 Distribution revenue forecast 2004/05 to 2008/09

Table A14.6 Building block core assumptions

$'000 $ of the year	2004/05	2005/06	2006/07	2007/08	2008/09
Opening RAB [1]	64,872	67,743	69,943	70,556	70,788
Operating Costs	9,971	10,128	10,288	10,452	10,620
Capital Expenditure	4,497	4,078	2,724	2,564	2,628
Forecast Network Sales (GWh)	278	284	290	295	301
Forecast Sales Growth (%)	2.1%	2.0%	2.0%	1.9%	1.9%

Notes
1. Includes adjustment to exclude street lighting and 1999-2004 capex underspend.

Table A14.7 Regulated distribution asset rolled forward from 1998/99 to 2003/04

$'000 $ of year	1998	1999	2000	2001	2002	2003	2004
Total value of assets							
Opening value		49,801	52,096	53,898	57,607	61,021	62,956
Capex/Additions [1]		3,358	2,705	3,036	4,316	3,183	5,095
depreciation		1,917	2,175	2,342	2,556	2,947	3,253
disposals		-	-	285	55	232	-
Indexation		854	1,272	3,300	1,709	1,931	1,965
Closing value	**49,801**	**52,096**	**53,898**	**57,607**	**61,021**	**62,956**	**66,763**

Notes:

1. Net of capital contributions.

Columns may not add due to rounding.

Table A14.8 Regulated distribution asset rolled forward from 2004/05 to 2008/09

$'000 $ of year	2005	2006	2007	2008	2009
Total RAB					
Opening value	66,763	67,743	69,943	70,556	70,788
Adjustment	-1,891				
Capex/Additions[1]	4,497	4,078	2,724	2,564	2,628
depreciation	3,304	3,623	3,893	4,128	4,371
disposals	0	0	0	0	0
Indexation	1,678	1,745	1,783	1,796	1,803
Closing value	**67,743**	**69,943**	**70,556**	**70,788**	**70,848**

Notes

1. Depreciation included in the building blocks calculated for the revenue requirement differs from the depreciation calculated for the asset base due to timing differences. Depreciation included in the building blocks is calculated in the middle of the year whereas depreciation for the asset base is calculated at the end of the year.
2. Net of capital contributions.

Columns may not add due to rounding.

A14.5 Notional and smoothed revenue requirements

Table A14.9 Notional and smoothed revenue requirement 2004/05 to 2008/09

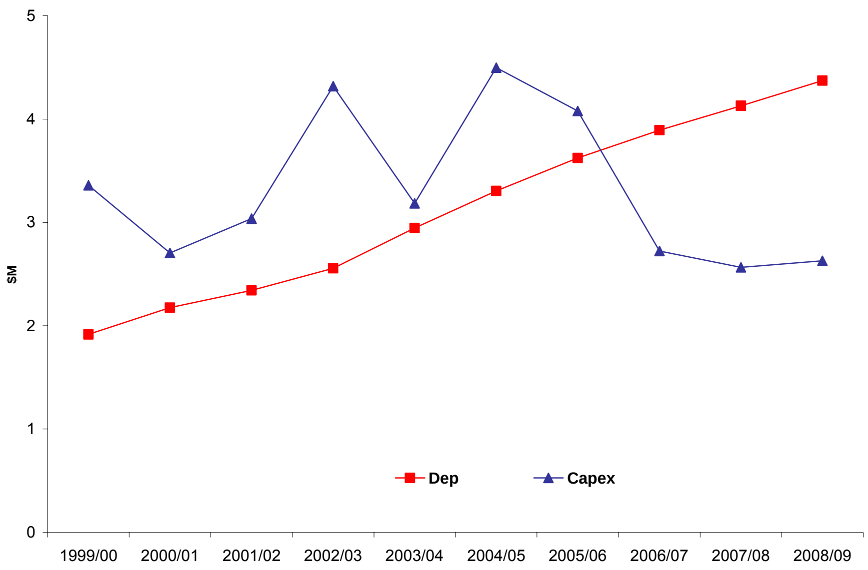
Financial year ending 30 June	2005	2006	2007	2008	2009
$'000 $ of the year					
Operating expenditure	9,971	10,128	10,288	10,452	10,620
Depreciation	3,155	3,459	3,717	3,942	4,174
Return on fixed assets	4,599	4,781	4,885	4,922	4,940
Return on working capital	273	283	289	297	310
Building Block Revenue	**17,998**	**18,651**	**19,179**	**19,612**	**20,043**
less correction for previous over/under recovery	(677)	(742)	(814)	(893)	(979)
Unsmoothed Revenue	**18,674**	**19,393**	**19,993**	**20,505**	**21,022**
Smoothed Revenue	**14,448**	**15,418**	**16,438**	**17,528**	**18,686**
Return on capital (real pre-tax)	**0.8%**	**1.4%**	**2.1%**	**2.9%**	**3.8%**
NPV of revenue foregone	**14,015**				

Notes:

1. Depreciation included in the building blocks calculated for the revenue requirement differs from the depreciation calculated for the asset base due to timing differences. Depreciation included in the building blocks is calculated in the middle of the year whereas depreciation for the asset base is calculated at the end of the year.
2. The difference between forecast unsmoothed and smoothed revenue in 2009 is due to the X-factor being rounded to one decimal place.

Columns may not add due to rounding.

Figure A14.1 Return of capital (depreciation) versus capex profile



A14.6 Distribution financial performance statement

Table A14.10 Distribution financial performance statement

$'000 $ of year	2005	2006	2007	2008	2009
Total revenue	**21,966**	**23,014**	**24,112**	**25,283**	**26,522**
Total costs	**17,490**	**17,723**	**17,962**	**18,206**	**18,456**
EBITDA	**4,477**	**5,291**	**6,150**	**7,076**	**8,066**
EBIT	**1,173**	**1,668**	**2,257**	**2,948**	**3,695**

Columns may not add due to rounding.

A14.7 Summary of rolled forward RAB

Table A14.11 Summary of rolled forward RAB

$'000 $ of the year	2005	2006	2007	2008	2009
Total system assets					
Opening value	57,044	59,683	61,913	63,151	64,131
Capex/Additions	3,275	2,940	2,023	1,842	1,888
depreciation	2,103	2,239	2,357	2,464	2,573
disposals	0	0	0	0	0
Indexation	1,467	1,529	1,573	1,602	1,627
Closing value	**59,683**	**61,913**	**63,151**	**64,131**	**65,074**
Total non-system assets					
Opening value	7,828	8,060	8,030	7,405	6,657
Capex/Additions	1,222	1,138	701	722	740
depreciation	1,200	1,384	1,536	1,664	1,798
disposals	0	0	0	0	0
Indexation	211	216	210	194	176
Closing value	**8,060**	**8,030**	**7,405**	**6,657**	**5,774**
Total RAB					
Opening value	64,872	67,743	69,943	70,556	70,788
Capex/Additions	4,497	4,078	2,724	2,564	2,628
depreciation	3,304	3,623	3,893	4,128	4,371
disposals	0	0	0	0	0
Indexation	1,678	1,745	1,783	1,796	1,803
Closing value	**67,743**	**69,943**	**70,556**	**70,788**	**70,848**

Notes:
All capex is net of capital contributions.
Columns may not add due to rounding.

LIST OF ABBREVIATIONS

1999 determination	IPART, *Regulation of New South Wales Electricity Distribution Networks - Determination and Rules under the National Electricity Code,* December 1999
ABARE	Australian Bureau of Agricultural and Resource Economics
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AGLGN	AGL Gas Networks
AGLSM	AGL Sales & Marketing
AGSM	Australian Graduate School of Management
ASP	Accredited Service Provider
BASIX	Building Sustainability Index
CAIDI	Customer Average Interruption Duration Index
Capex	Capital Expenditure
CAPM	Capital Asset Pricing Model
CBD	Central Business District
CGS	Commonwealth Government Securities
COAG	Council of Australian Governments
Code	National Electricity Code
CPI	Consumer Price Index
CRNP	Cost Reflective Network Pricing
Determination	IPART, *NSW Electricity Pricing 2004/05-2008/09 Final Determination*, June 2004
DLF	Distribution Loss Factor
DEUS	Department of Energy Utilities and Sustainabilities
DM	Demand Management
DNSP	Distribution Network Service Provider
DORC	Depreciated Optimised Replacement Cost
Draft Report	IPART, *NSW Electricity Pricing 2004/05-2008/09 Draft Report*, January 2004
DUOS	Distribution Use of System
EDL	Electricity Distributor Levy
EBITDA	Earnings before Interest Tax Dividends and Abnormals

EMRF	Energy markets Reform Forum
ESC of Victoria	Essential Services Commission of Victoria
ESCOSA	Essential Services Commission of South Australia
EUAA	Energy Users Association of Australia
EWON	Energy &Water Ombudsman of NSW
FRC	Full Retail Contestability
GCSS	Guaranteed Customer Service Standards
GSP	Gross State Product
GWh	Gigawatt hour = 1,000,000 kilowatt hours or 1,000 MWh
HV	High Voltage – normally refers to voltages greater than 22kV
IDT	Inter distributor transfers
IPART	Independent Pricing and Regulatory Tribunal (also (represented as the Tribunal)
kV	Kilovolt = 1,000 volts
kVA	Kilovolt Amp = 1,000 volt-amperes
kW	Kilowatt = 1,000 watts
KWh	Kilowatt hours
LGA	Local Government Association
LV	Low voltage, normally refers to 240/415 volt distribution for customer installations
MAIFI	Momentary Average Interruption Frequency Index
MEU	Ministry of Energy and Utilities (now DEUS)
MMA	McLennan Magasanik Associates
MRP	Market Risk Premium
MS	Modified Standard measure which excludes major natural events and planned interruptions
MSATS	Market Settlement and Transfer Solution
MW	Megawatt
MWh	Megawatt hour = 1,000 kilowatt hours
NECA	National Electricity Code Authority
NECA	National Electrical Contractors Association
NEMMCO	National Electricity Market Management Company
NIEIR	The National Institute of Economic and Industry Research
NMI	National Meter Identifier RAB

NRGP	Network Region Gross Product
NUOS	Network Use of System
ODRC	Optimised Depreciated Cost (also known as DORC)
OFGEM	Office of Gas and Electricity Markets (UK)
Opex	Operating Expenditure
ODV	Optimised Deprival Valuation
PIAC	Public Interest Advocacy Centre
PICG	Pricing Issues Consultation Group
PPM	IPART, *Pricing Principles and Methodologies for Prescribed Electricity Distribution Services,* March 2001
RAB	Regulatory Asset Base
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
S&P	Standard and Poor
SCNRRR	Steering Committee on National Regulatory Reporting Requirements
SKM	Sinclair Knight Merz
TNSP	Transmission Network Service Provider
Tribunal	Independent Pricing and Regulatory Tribunal
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap