Price and Service Report

NSW Electricity Distribution Businesses

1999/2000

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

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Other Paper OP-10 **July 2001**

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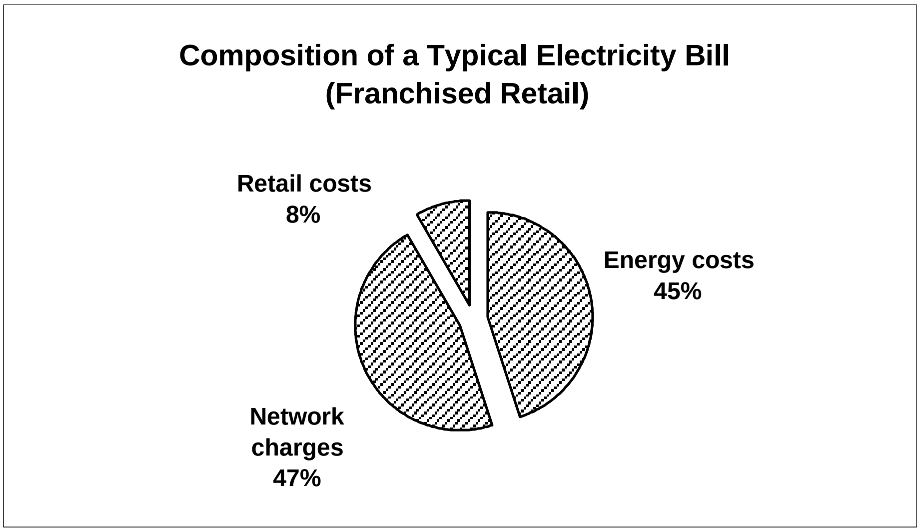
1 INTRODUCTION

This report provides information on the performance of the six electricity distribution businesses that operated in NSW (the Distribution Network Service Providers or DNSPs) prior to 1 July 2001.[1] Its aim is to provide customers and other stakeholders with access to comparative data on the prices and service levels of the DNSPs and make the pricing decisions and methodologies of these businesses more transparent.

As this is the Tribunal's first Price and Service Report, its content largely reflects the factual information provided to the Tribunal by the DNSPs. In future reports, it is our intention to provide greater commentary and analysis of the information presented. The structure and content of the report is likely to evolve over time and in response to consultation. The Tribunal welcomes any feedback on this report and its usefulness. For more information on the background to the report, and why it has been produced, see Appendix 1.

It is important to note that no end-use customer receives a bill from a DNSP – Retailers incorporate distribution costs into the final retail price. As shown in the figure below, distribution network costs make up around 47 per cent of a typical franchised customer bill. Network costs in the chart include the transmission use of system[2] (TUOS) costs as well as all specific distribution network costs.

Figure 1.1 Composition of typical bill



[1] Effective on 1 July 2001, the NSW Government merged the three electricity distribution business of Great Southern Energy, Advance Energy and NorthPower. The new entity is known as Country Energy.

[2] DNSPs pay a regulated charge to the Transmission Network owner (TransGrid) for use of the transmission system in transporting electricity from the generator to the distribution network.

This report is based on information provided to the Independent Pricing and Regulatory Tribunal (the Tribunal) by each DNSP in its 2001 Pricing Information Package and annual Regulatory Accounts, and on data provided to the Ministry of Energy and Utilities (MEU). It summarises and compares the DNSPs in six categories:

- general operating background
- typical bills and average prices
- pricing methodologies and cost allocation approaches
- issues likely to affect pricing in the medium term
- standards of service
- financial performance.

2 GENERAL OPERATING BACKGROUND

The six DNSPs in NSW are EnergyAustralia, Integral Energy, NorthPower, Great Southern Energy, Advance Energy and Australian Inland Energy and Water.[3] Their areas of operation vary widely (see Table 2.1 and Figure 2.1). For example, EnergyAustralia and Integral Energy operate in densely populated urban districts, so although they cover relatively small geographic areas, they serve large numbers of customers and have high numbers of employees. The remaining four DNSPs are based in rural areas, so cover much larger operating areas, serve fewer people and have fewer employees.

Table 2.1 General operating statistics (1999/2000)

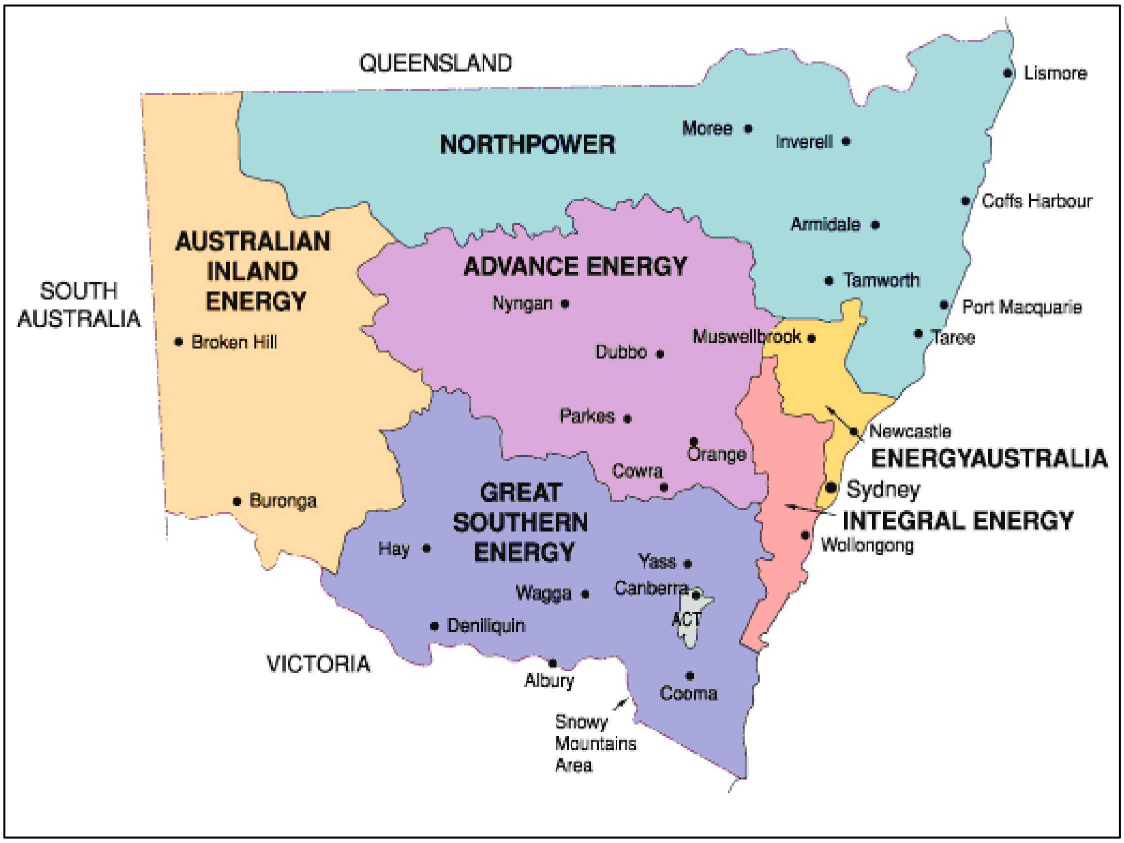
		Energy Australia	Integral Energy	NorthPower	Great Southern Energy	Advance Energy	Aust Inland Energy & Water
Total operating area	km2	22,275	24,500	230,000	176,000	167,000	155,000
Employee numbers (full time equivalent) year end							
- network	no.	2,294	1,161	918	503	492	83
- retail	no.	355	-	53	-	81	25
- non-regulated businesses	no.	633	507	123	203	17	-
- total	no.	3,282	1,668	1,094	706	590	108
Network customers	no.	1,399,443	743,243	365,542	231,013	120,023	18,896
Customers per employee (network)	no.	610	640	398	460	244	228
Total energy sales	GWh	24,364	12,804	3,950	2,990	2,708	380
Total length of wires	km	51,878	32,421	74,987	59,306	42,048	9,458
Length of underground wires included above	km	12,611	7,947	2,088	918	800	31
Length of new wire route added during year	km	403	680	530	452	197	6

Sources: Pricing Information Packages (other than customer numbers and energy sales, which are sourced from 1999/2000 Regulatory Accounts)

Great Southern Energy, NorthPower and Advance Energy will merge to form Country Energy from 1 July 2001. In this report, however, the Tribunal has presented information on the three separate businesses.

3 On 1 July 2001 Great Southern Energy, NorthPower and Advance Energy merged to form Country Energy.

Figure 2.1 Operation areas



3 TYPICAL BILLS AND AVERAGE PRICES

A comparison across the six DNSPs of distribution costs for like customers at chosen consumption levels is a reasonable way of comparing the impact of DNSP charges on customers. This approach removes any impact of differences in customer mix and consumption levels in each area, effectively comparing 'like with like'. For instance, Table 3.1 demonstrates that a 'typical' domestic customer in NSW consuming 3.5MWh per annum can pay between $184 and $244 for a year's network services.

Typical[4] network bills in each tariff category vary quite widely across the DNSPs. For example:

- The highest typical domestic network charge (Advance Energy) is $60 (*or 33 per cent*) more expensive than the lowest (EnergyAustralia).
- The highest typical business (non time of use) general supply charge, at consumption of 18MWh per annum, (NorthPower) is $580 (*or 70 per cent*) more expensive than the lowest (Integral Energy).
- The highest typical business (time of use) low voltage demand charge, with 40 per cent load factor, (Australian Inland Energy and Water) is $73,000 (*or 155 per cent*) more expensive than the lowest (Great Southern Energy).
- The highest typical business (time of use) high voltage demand charge, with 60 per cent load factor, (Australian Inland Energy and Water) is $229,275 (*or 115 per cent*) more expensive than the lowest (Great Southern Energy).

In general, the typical business customer charges for the urban DNSPs (EnergyAustralia and Integral Energy) are lower than those of the rural DNSPs (with the exception of GSE). However, Integral Energy's typical domestic charge is in fact higher than those of two of the four rural DNSPs. Some of the differences between DNSPs in these typical customer charges may be due to the diversity of capacity and network sizes. For further information on the cost drivers impacting on each DNSP, refer to Chapter 4 of this Report, or to the individual Pricing Information Packages of the DNSPs.

4 Certain, standard consumption levels (and load factor, where appropriate) have been chosen in each tariff category to illustrate the network charges associated with these consumption levels, for the purposes of comparison across the six DNSPs. These consumption levels have been chosen as 'typical' from the range of consumption levels presented in the Electricity Supply Association of Australia's publication, *Electricity Prices in Australia 2000/2001*.

Table 3.1 Network component of charges for 'typical' customers ($ per customer per year)

	Con-sumption	EnergyAustralia		Integral Energy		NorthPower		Grt. South. Energy		Advance Energy		Aus Inland E & W	
	MWh pa	2000/01 bill ($)	% chg from 1999/00	2000/01 bill ($)	% chg from 1999/00	2000/01 bill ($)	% chg from 1999/00	2000/01 bill ($)	% chg from 1999/00	2000/01 bill ($)	% chg from 1999/00	2000/01 bill ($)	% chg from 1999/00
Domestic													
Domestic	3.5	184	-9%	214	2%	241	6%	203	-5%	244	3%	207	9%
Domestic with controlled load hot water	7.5	229	-11%	281	2%	279	5%	253	-4%	326	3%	284	9%
Rural Domestic	12.0	-	na	613	2%	-	na	803	-5%	863	3%	811	9%
General supply													
Business non-TOU, 18 MWH cons.pa	18.0	839	-6%	831	2%	1,411	4%	1,004	2%	1,168	3%	1,284	12%
Business non-TOU, 60 MWH cons. pa	60.0	2,531	-6%	2,654	2%	4,455	1%	3,029	1%	3,534	3%	3,978	9%
Low Voltage TOU													
Business TOU with 60% load f.	263	9,998	-6%	10,165	2%	13,885	-1%	8,913	2%	13,482	3%	24,774	9%
Business TOU with 30% load f.	438	14,966	-4%	14,241	3%	21,565	-1%	13,178	4%	19,622	3%	17,420	9%
Low Voltage Demand													
LV Demand TOU (kVA), with 20% load f.	876	44,831	-21%	47,491	2%	71,961	-1%	42,691	-1%	56,502	6%	89,772	9%
LV Demand TOU (kVA), with 40% load f.	1,752	55,998	-14%	56,507	2%	87,823	-1%	47,233	-1%	72,708	12%	120,296	9%
LV Demand TOU (kVA), with 60% load f.	2,628	65,071	-7%	62,499	2%	100,370	-1%	50,223	-1%	85,936	19%	144,663	9%
High Voltage Demand													
HV Demand TOU (kVA), with 40% load f.	8,760	208,022	-13%	204,326	3%	339,118	-1%	187,498	-1%	311,856	3%	356,708	9%
HV Demand TOU (kVA), with 60% load f.	13,140	240,275	-9%	235,307	3%	400,942	-1%	199,974	-1%	379,746	3%	429,249	9%
HV Demand TOU (kVA), with 80% load f.	17,520	262,969	-4%	249,740	4%	446,409	-1%	204,872	-1%	430,992	3%	481,143	9%

Sources: Pricing Information Packages and (for Advance Energy) 2000 Regulatory Accounts

Note: AIEW data for Low Voltage TOU applies to a 50%, not 60%, load factor.

An alternative means of contrasting network prices across the six DNSPs is to compare average network charges in a range of tariff categories, as shown in Table 3.2. However, such a comparison may be misleading, as average network prices will be influenced by customer mix, volumes consumed and different tariff structures.[5]

The average network charges in each tariff category vary quite widely across the DNSPs.[6] For example:

- The highest average residential network price (NorthPower) is $0.95 per kWh (*or 26 per cent*) more expensive than the lowest (Great Southern Energy).
- The highest average price for general supply low voltage (Australian Inland Energy and Water) is $2.43 (*or 69 per cent*) more than the lowest (Integral Energy).
- The highest average price general supply high voltage (Great Southern Energy) is $3.23 per kWh (*or 221 per cent*) than the lowest (Integral Energy).

Table 3.2 Average charges and usage for network customers (1999/2000)

		Energy Australia	Integral Energy	NorthPower	Great Southern Energy	Advance Energy	Aust Inland Energy & Water
Average network charges per unit of consumption							
Urban residential	c/kWh	np	4.40	4.66	3.71	4.39	3.72
General supply LV	c/kWh	np	3.55	5.86	4.56	4.90	5.98
General supply HV	c/kWh	np	1.46	3.15	4.69	3.42	na
Rural/farms	c/kWh	np	-	6.51	4.79	5.77	4.11
Streetlighting	c/kWh	np	3.82	4.40	4.80	4.27	4.41
Average network charge per customer							
Urban residential	$/customer	307	360	297	244	335	252
General supply LV	$/customer	997	2,227	2,309	714	4,200	13,691
General supply HV	$/customer	123,859	211,560	185,361	37,484	330,000	na
Rural/farms	$/customer	-	-	563	435	564	268
Streetlighting	$/customer	116,748	34,026	13,479	20,976		1,304
Average network customer usage							
Urban residential	MWh/year	7.7	8.2	6.4	6.6	7.6	4.9
General supply LV	MWh/year	22.0	62.8	39.4	15.7	86.0	228.9
General supply HV	MWh/year	6,966	14,536	5,893	800	9,750	na
Rural/farms	MWh/year	-	-	8.7	9.1	9.8	6.5
Streetlighting	MWh/year	3,070	890	306	44		30

Notes: 1. The non-domestic categories may not be strictly comparable between all agencies due to differences in the structure of tariffs.
2. For Advance Energy, "General Supply LV" price refers to the non-domestic LV TOU tariff.
3. Australian Inland Energy's figures are provisional. The information for HV customers is confidential and therefore cannot be shown.
np = not provided.
Source: Pricing Information Packages

The following table demonstrates how average network tariffs have changed in each DNSP area since 1996/97 (where the data have been provided).

5 For instance, Advance Energy advises that it does not have a general supply HV network price and notes that the table does not contain TOU or demand based tariffs (see note at bottom of table).

6 This is the calculated average amount paid per unit, which depends on the level of both fixed and variable charges. It is not a price that is actually charged to the Retailer or the end use customer.

Table 3.3 Average prices for network customers 1996/97 to 1999/2000

1999/2000 c/kWh	**1996/1997**	**1997/1998**	**1998/1999**	**1999/2000**
EnergyAustralia				
Residential	np	np	np	np
Non Residential	np	np	np	np
All customers	***4.12***	***4.02***	***3.68***	***3.77***
Integral Energy				
Residential	4.92	4.96	4.89	4.40
Non Residential	2.74	2.59	2.71	3.04
All customers	***3.57***	***3.45***	***3.51***	***3.64***
NorthPower				
Residential	np	np	np	np
Non Residential	np	np	np	np
All customers	***5.05***	***5.28***	***5.25***	***5.32***
Great Southern Energy				
Residential	np	4.00	4.02	4.03
Non Residential	np	5.25	4.87	4.65
All customers	***np***	***4.67***	***4.47***	***4.35***
Advance Energy				
Residential	4.84	4.99	4.89	4.78
Non Residential	3.30	3.16	2.59	3.06
All customers	***3.90***	***3.87***	***3.31***	***3.57***
Australian Inland Energy				
Residential	np	np	np	np
Non Residential	np	np	np	np
All customers	***3.73***	***3.76***	***3.52***	***3.42***

Source: Regulatory Accounts.
np: not provided.

4 PRICING METHODOLOGIES AND COST ALLOCATION APPROACHES

The prices DNSPs charge are regulated by the Tribunal in the form of a revenue cap. In the current regulatory period (1 February 2000 to until 30 June 2004), the Tribunal has set a base revenue allowance for each DNSP for each year of the period. Each DNSP is entitled to add other specified revenue components to this base revenue (such as transmission charges, avoided transmission–use-of-system (TUOS) payments to embedded generators,[7] and the net impact of the GST). The base revenue allowance plus these other components make up the DNSP's annual aggregate revenue requirement (or AARR), and it is not entitled to raise more than this AARR.

DNSPs are free to structure specific prices (or tariffs) within the bounds of this revenue cap, subject to certain limits on price movements imposed by the Tribunal. These limits are:

- average prices across the network must not increase by more than CPI
- a residential customer's network bill must not increase by more than the greater of CPI plus 2 per cent, or $30 per annum, for the same quantity and pattern of consumption as the previous year.

In addition, the DNSPs are required to publish the methodology they use to derive their prices in an annual Pricing Information Package. DNSPs are asked to explain the relationship between these prices and their costs, how costs are allocated between distribution services and customer classes, and how tariffs have been structured. Table 4.1 summarises the approach of each DNSP to these matters.

Integral Energy, EnergyAustralia, Advance Energy and Great Southern Energy use a similar approach. They:

- employ a fully distributed cost model to allocate the AARR between asset categories or 'cost pools' and then
- allocate these cost pools to customer classes based on their use of network assets.

(See Appendix 2 for an overview of different cost allocation methodologies.)

Australian Inland Energy and Water also allocates network costs to customer classes based on use of assets, but allocates AARR according to historical tariff structures, rather than by any relation to asset cost categories. It has advised the Tribunal that it intends to implement a comprehensive network pricing model by 1 July 2002, which will incorporate the cost allocation by asset category approach.

NorthPower uses a slightly different approach, allocating the AARR to four cost drivers—demand, energy, customers and miscellaneous—and then sharing these costs between customer classes based on use of assets.

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7 Payments to embedded generators may be made by a DNSP for avoided TUOS charges where a generator establishes a plant within the distribution network. A generation plant that uses only the distribution network will save the DNSP the transmission charges otherwise payable for the amount of energy produced by the embedded generator. The DNSP may then claim these payments to an embedded generator as a cost to be added to its total regulated revenue allowance.

Table 4.1 Cost allocation, customer classification and tariff structure approaches

	Cost Allocation	Basis Customer Classification	Tariff Structures
EnergyAustralia	• Allocates AARR to 10 asset categories or 'cost pools' • Allocates cost pools to customer classes based on use of network assets	• voltage level • type of meter or type of usage • location (for large customers)	• fixed network access charge plus • energy charge (can be TOU*) plus in some instances • demand charge[8] (TOU) plus in some instances • capacity charge (TOU) (* TOU means 'time of use')
Integral	• Allocates AARR to 10 asset categories or 'cost pools' • Allocates cost pools to customer classes based on use of network assets	• voltage level • location • load shape • type of meter	• fixed network access charge plus • energy charge (can be TOU) plus in some instances • demand charge (can be TOU) plus in some instances • controlled load (mainly domestic customers)
Advance	• AARR allocated to 20 asset categories or 'cost pools' • Cost pools then allocated to customer classes based on use of network assets	• voltage level • location • load shape • type of meter	• fixed component, plus • energy charge (can be TOU) plus in some instances • demand time of use and in some instances • controlled load
NorthPower	• Allocates AARR to 4 'cost pools' – customer, demand and energy services and 'miscellaneous' • Allocates costs to customers based on use of network assets	• voltage level • assets required (generally an urban/non-urban division)	• fixed component • energy component • demand component (where metering permits)
GSE	• Allocates AARR to 22 asset categories or 'cost pools' • Allocates cost pools to customer classes based on use of network assets	• voltage level • location	• fixed network access charge plus • energy charge (can be TOU) plus in some instances • demand charge (can be TOU) plus in some instances • capacity charge, plus in some instances • equipment rental charge
AIE	• Allocates network costs to customer classes based on use of network assets[9] • Averages prices by customer class • Allocates costs by kWh to each tariff in direct kWh ratio	• voltage level	• fixed component plus • energy component plus in some instances • time of use component (where metering permits) plus in some instances • demand component (where metering permits)

8 All DNSPs generally apply a demand charge specified in $/kVA.

9 AARR not yet apportioned by asset category, but rather derived from former franchise tariffs, discounted by energy costs and adjusted within side constraints.

5 STANDARDS OF SERVICE

The Tribunal has recently taken over responsibility for administering the licensing of NSW electricity distribution and retail businesses and reporting on compliance with licence conditions, from the Ministry of Energy and Utilities. The Minister for Energy has asked the Tribunal to review the licensing regimes for electricity and gas and provide a final report by May 2002.[10]

The MEU will continue to provide policy advice to the Minister and to regulate network management. The MEU has advised[11] that its focus over the next few years will be to further develop the network management framework to promote improved:

- transparency on network management issues, including reliability planning standards
- network performance measurement and reporting
- national consistency on performance benchmarking
- accountability of network operators
- outcomes for reliability and quality of supply.

Under the current industry licensing regime,[12] however, the DNSPs do not have to meet specific service standards—rather, they are able to nominate their own performance targets in their licence plan and are required to provide data to MEU and the Tribunal on their performance. Performance measures for electricity distribution service typically fall into three categories:

- network reliability measures, which indicate how often and for how long customers lose their electricity supply
- technical or service quality measures, which relate to the quality of the electricity supply received by customers (eg voltage levels)
- customer service measures, which relate to a distributor's responsiveness and timeliness in their interactions with customers.

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10 The Minister for Energy has made this request under section 9(1)(b) of the IPART Act 1992. The Terms of Reference have been listed on the Tribunal's website. Other developments in relation to regulating service standards include the working groups established by the national Regulators Forum under the auspices of the Steering Committee on National Regulatory Reporting Requirements. The objective of these working groups is to develop a national approach to performance measurement through the alignment of jurisdictional regulatory accounts and quality of service reporting frameworks. IPART is chairing a Working Group aimed at aligning distribution quality of supply measures. This Group intends to complete a final report by the end of June 2001.

11 Advice from Mr M Overy, MEU, 2 May 2001.

12 Established under the *Electricity Supply Act 1995*.

5.1 Network reliability

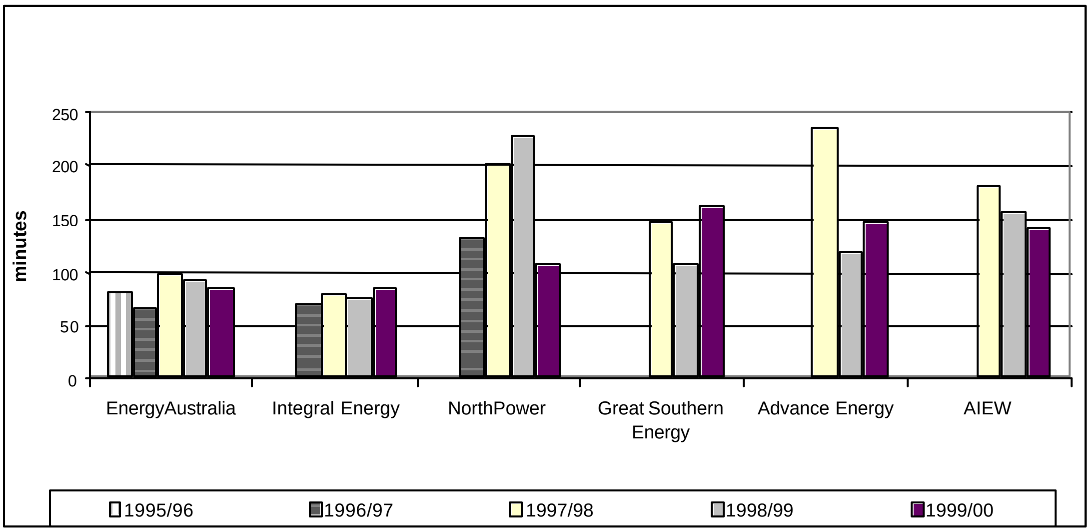
Network reliability measures are widely used and fairly standardised. Table 5.1 lists the indices commonly used to measure the duration and frequency of supply interruptions.

Table 5.1 Supply interruption indices

Index	Measure/description	Definition
SAIDI System Average Interruption Duration Index	Total number of minutes, on average, that a customer is without electricity in a year	Total customer minutes interrupted per year/average total no. of customers
SAIFI System Average Interruption Frequency Index	Average number of times a customer's supply is interrupted per year	Total number of customer interruptions per year/average total no. of customers
CAIDI Customer Average Interruption Duration Index	Average duration of each interruption	Total customer minutes interrupted/total no. of customer interruptions (= SAIDI/SAIFI)

The following figures summarise each DNSP's performance on these measures over the past five years (where data available).

Figure 5.1 System average interruption duration index (SAIDI)



When comparing DNSPs, note that performance against these measures is influenced by factors such as historical capital expenditure decisions, geography, demographics, storm frequency, the extent of undergrounding of network, and the level of redundancy in the network. In addition, these measures represent averages across each DNSP's region. It is likely that there are areas within each region where these measures vary significantly from the average. For the individual customer, actual local reliability is of much more concern than the regional average. In recognition of this, the MEU requires reporting of individual feeders with unsatisfactory reliability, together with causes and remedial actions, until performance is again satisfactory.

Figure 5.2 Customer average interruption duration index (CAIDI)

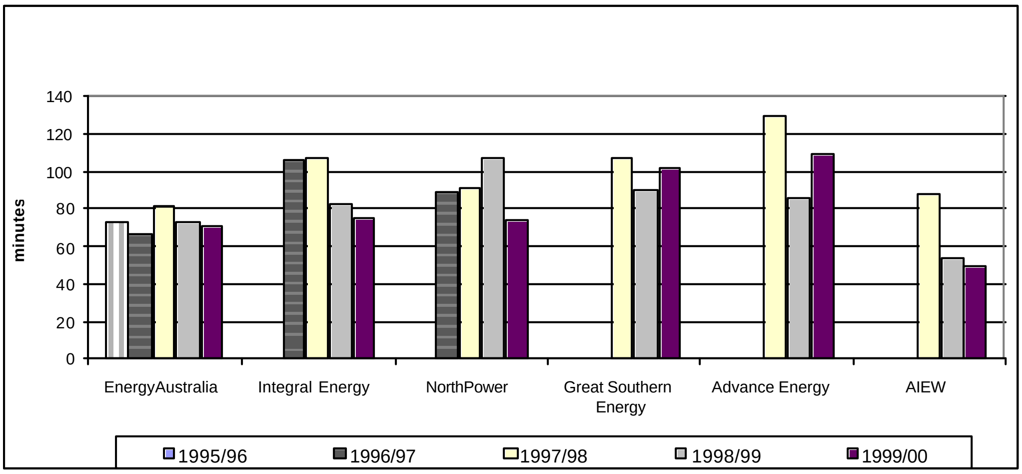
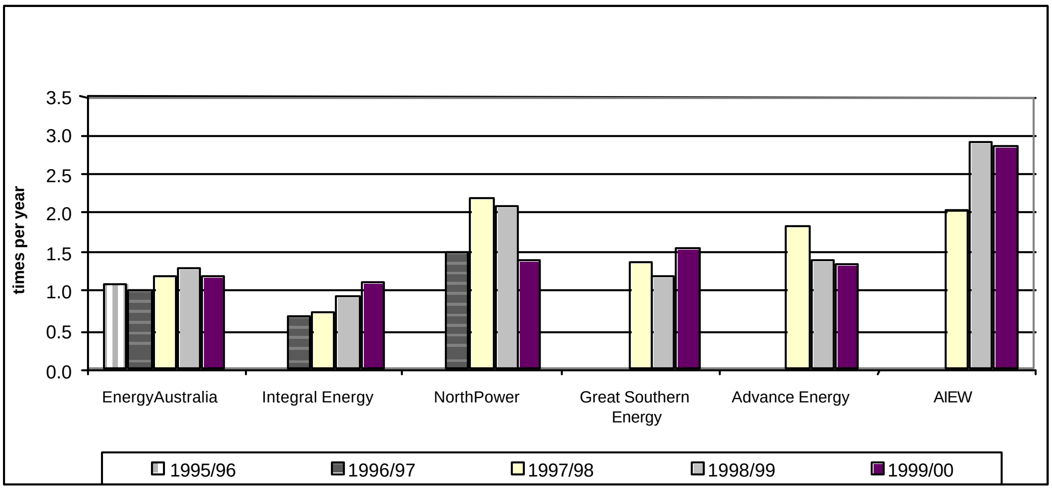


Figure 5.3 System average interruption frequency index (SAIFI)



5.2 Technical or service quality

In general, very little measurement of technical quality of supply is being done, although this area of performance is a major customer concern. From the DNSP's point for view, the main difficulties in measuring quality of supply are that it is expensive and problems are often localised and transient. The only measure currently reported to the Ministry of Energy and Utilities is complaints. The MEU has established a working group to recommend a supply quality reporting regime.

The quality of supply measures being used by DNSPs include:

- range of supply voltage
- frequency of supply
- voltage fluctuations
- lightning surges
- harmonic content of voltage and current.

5.3 Customer service

DNSPs are required to report against a range of customer service measures. These include guaranteed service levels, which require a compensation payment to be made to a customer if the standard is not met. For example, DNSP licence conditions require that:

- Connections must be provided by a date agreed with the customer, or the DNSP must pay the customer $60 per day until provided (to a maximum of $300).
- For planned interruptions, customers must be given two days notice and advised of the length of interruption, or the DNSP must pay the customer $20 (for insufficient notice, or exceeding advised duration of outage).
- Streetlights must be repaired by an agreed date, or the DNSP must pay the customer $15 (flat payment).
- DNSP staff cannot be more than 15 minutes late in keeping customer appointments, or the DNSP must pay the customer $25.

For a detailed description of the DNSPs' performance against a range of key performance indicators, see Appendix A1 of the Tribunal's 1999/2000 Compliance Report.[13]

13 IPART, *Electricity distribution and retail licences: compliance report for 1999/2000 – Report to the Minister for Energy*, Compliance Report No 2, December 2000.

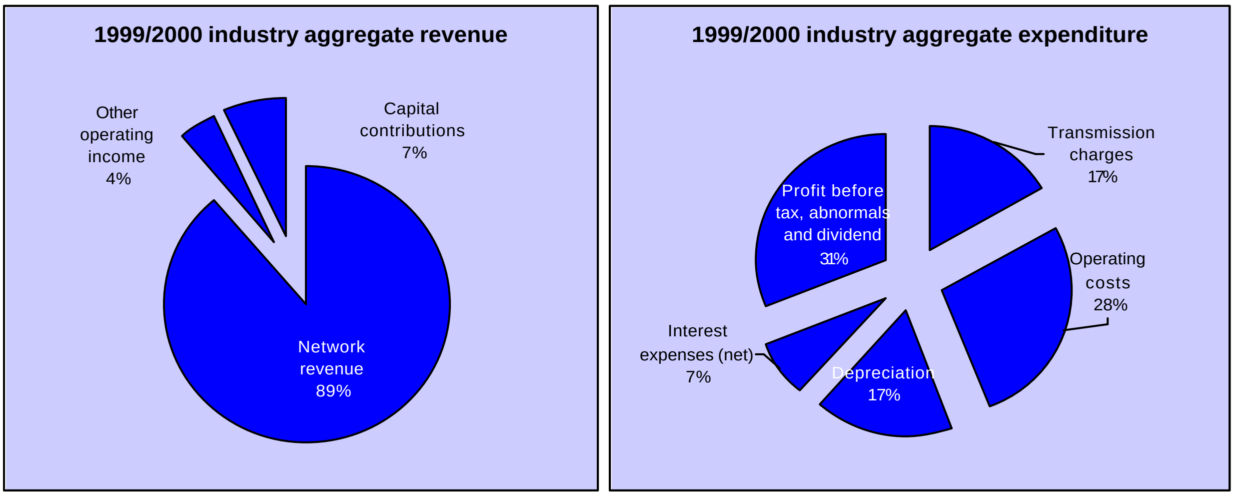
6 FINANCIAL PERFORMANCE

This chapter summarises the financial performance of the NSW DNSPs. The information is mostly for the year ended 30 June 2000. The chapter also compares over time the operating performance of the industry at an aggregate level as well as individual DNSPs' performance. The data used in the analysis has been drawn mainly from the audited Regulatory Accounts.

The 1999/2000 financial year is the first of the new regulatory period running from 1999/2000 to 2003/2004 covered by the 1999 Network Determination.[14] However, the current 1999 Network Determination applies from 1 February 2000. For the first seven months of the 1999/2000 financial year, the maximum allowable revenue for network was derived using the 1996 and 1997 Determinations.

Figure 6.1 presents the components of the aggregate revenue and expenditure of the six DNSPs.

Figure 6.1 Aggregate income and expenditure of DNSPs in 1999/2000



Source: 1999/2000 Regulatory Accounts.

6.1 Revenue and profitability

In 1999/2000, the aggregate network revenue totalled $1,728m and the industry-wide EBITD[15] margin was 53 per cent. This compares favourably with that of the electricity/water/gas sector (32 per cent) in the fiscal year 2000.[16]

As shown in Table 6.1 the industry EBIT[17] margin averaged 34 per cent in 1999/2000 with a range of 23 per cent to 40 per cent. The aggregate return on assets was around 7.4 per cent in 1999/2000.[18]

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14 IPART, *Regulation of New South Wales Electricity Distribution Networks, December 1999,* NEC Determination 99-1.

15 EBITD means earnings before interest, tax and depreciation.

16 Business Review Weekly, 17 November 2000 issue, p 105.

17 EBIT means earnings before interest and tax.

18 This is based on the regulatory asset value of the distribution network assets.

Table 6.1 Income and expenditure of DNSPs - 1999/2000

$ million (nominal)	Energy Australia	Integral Energy	NorthPower	Great Southern Energy	Advance Energy	AIEW	All DNSPs
Network use of system charge	832.6	459.1	203.2	130.2	88.3	14.4	1,727.7
Other operating income	24.5	32.2	13.1	5.5	6.1	4.4	85.7
Transmission charges	(142.0)	(87.5)	(42.5)	(27.3)	(19.7)	(4.9)	(324.0)
Operating costs	(209.1)	(160.3)	(74.0)	(49.7)	(35.9)	(7.2)	(536.2)
EBITD	506.0	243.4	99.7	58.7	38.8	6.7	953.2
Depreciation	(166.3)	(84.0)	(49.5)	(19.4)	(16.3)	(2.3)	(337.8)
EBIT	339.7	159.4	50.2	39.3	22.5	4.3	615.4
Net interest expense/(income)	(76.9)	(59.5)	(8.9)	(0.3)	(1.4)	1.0	(143.7)
Profit before tax	262.8	102.1	41.3	39.1	21.1	5.3	471.7
Capital contributions	62.7	25.1	23.3	12.9	8.2	1.1	133.3
	325.5	127.3	64.6	52.0	29.3	6.5	605.1
EBITD/Revenue	59%	50%	46%	43%	41%	35%	53%
EBIT/Revenue	40%	32%	23%	29%	24%	23%	34%

Source: 1999/2000 Regulatory Accounts. Abnormal items and CSOs are excluded
Columns may not add due to rounding.

The DNSPs have the following over and under recovery in network revenue in 1999/2000.

Table 6.2 Over and under recovery of regulated network revenue - 1999/2000

$ million (nominal)	Energy Australia	Integral Energy	NorthPower	Great Southern Energy	Advance Energy	Aust Inland Energy & Water
Regulated network revenue (note 1)	924.5	470.6	209.8	133.8	89.8	14.5
Maximum allowable network revenue	819.5	476.8	202.1	135.4	92.0	14.5
Over /(under) recovery for 1999/2000	105.0	(6.2)	7.8	(1.6)	(2.2)	(0.1)
Over/(under) recovery as a % of regulated network revenue	12.8%	-1.3%	3.8%	-1.2%	-2.4%	-0.3%
Balance at 30 June 1999	96.5	10.8	2.9	1.0	(5.1)	(0.2)
Over /(under) recovery for 1999/2000	105.0	(6.2)	7.8	(1.6)	(2.2)	(0.1)
Interest charge/credit	12.1	0.3	0.6	(0.0)	(0.4)	(0.0)
Balance at 30 June 2000	213.6	4.9	11.3	(0.7)	(7.8)	(0.3)

Source: 1999/2000 Regulatory Accounts
Columns may not add due to rounding.
Note 1: network use of system charges for full year, and streetlighting, monopoly fees and miscellaneous charges from 1 February 2000

6.2 Network costs

6.2.1 Network operating costs

Table 6.3 shows network operating costs reported by the DNSPs, compared with the target operating costs allowed in the 1999 Network Determination.

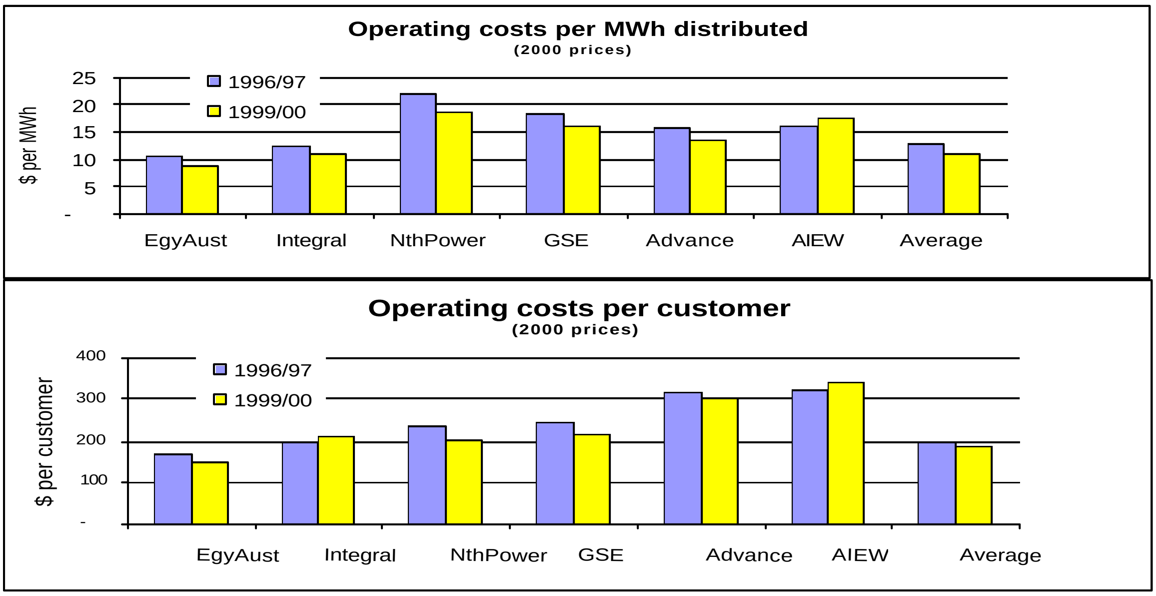
Table 6.3 Comparison of 1999/2000 actual operating costs with 1999 Network Determination targets for that year

$ million (nominal)	1999/00 opex allowed in 1999 Determ.	1999/00 Actual	Actual exceeds Determ. Opex	Actual exceeds Determ. Opex (%)
EnergyAustralia	205.6	209.1	3.5	2
Integral Energy	157.2	160.3	3.2	2
NorthPower	70.7	74.0	3.3	5
Great Southern Energy	47.6	49.7	2.0	4
Advance Energy (Note 1)	43.8	35.9	(7.9)	-18
Aust Inland Energy & Water	6.9	7.2	0.4	6
DNSPs total	**531.8**	**536.2**	**4.5**	**1**

Source: 1999/2000 Regulatory Accounts and 1999 Network Determination.
Columns may not add due to rounding.
Note 1: The 1999/2000 regulatory accounts of Advance Energy indicate that costs allocated to unregulated businesses increased by 65%, which effectively reduced operating costs allocated to the regulated network business.

Figure 6.2 show partial efficiency measures in terms of operating costs per MWh distributed and per customer for 1996/97 and 1999/2000. Industry wide, operating costs per MWh distributed fell from $13/MWh to $11/MWh and operating costs per customer reduced from $195 to $185 in real terms over the period. Underlying the above efficiency improvement is a 16 per cent load growth and 5 per cent customer growth in the industry over the period.

Figure 6.2 Operating cost per MWh and per customer



Typically, the rural DNSPs have operating costs per MWh and per customer higher than the DNSP average.

6.2.2 Interest expenses

Interest expenses paid by the DNSPs totalling $146m in 1999/2000 compares with $213m in 1996/97. This represents a nominal reduction of 32 per cent. This has helped to improve the profitability of the DNSPs. The average interest rate has decreased from 9 per cent in 1996/97 to 7 per cent in 1999/2000. This decline is generally in line with market interest rate movements over the period.

6.3 Tax and dividends

Tax and dividends paid are based on profits of the aggregate regulated and unregulated businesses of the distributors. These payments decreased to $344m in 1999/2000 from $450m in 1998/99. Shown below are taxes and dividends paid over the past four years.

Table 6.4 Tax and dividend payments - 1996/97 to 1999/2000

$ million (nominal)	1996/97 Actual	1997/98 Actual	1998/99 Actual	1999/00 Actual
Tax	199.0	258.0	179.0	49.0
Dividends	362.0	412.0	271.0	295.0
Total	561.0	670.0	450.0	344.0
Group profit before tax	516.0	823.0	487.0	670.0
Tax & dividends as % of profit before tax (Note 1)	109%	81%	92%	51%

Source: Regulatory Accounts

Columns may not add due to rounding.

Note 1: Taxes and dividends are paid on the aggregate profits of distributors' regulated (including network and regulated retail) and non-regulated (including contestable retail) businesses.

Taxes and dividends paid by the DNSPs in 1999/2000 are detailed below.

Table 6.5 Tax and dividend payments - 1999/2000 Actual

$ million (nominal)	Tax	Dividend
EnergyAustralia	51.7	184.3
Integral Energy (note 1)	-28.7	29.7
NorthPower (note 2)	-2.9	31.7
Great Southern Energy	25.1	35.3
Advance Energy	1.3	11.1
Australian Inland Energy	2.7	2.7
Distributor total	49.2	294.8

Source: 1999/2000 Regulatory Accounts

Columns may not add due to rounding.

Note 1: Integral Energy's tax credit arose from restatement of deferred balances due to changes in accounting policy.

Note 2: Due to tax being incorrectly levied on prior years' capital contributions, NorthPower was entitled to a tax credit in 1999/2000.

Note 3: Taxes and dividends are paid on the aggregate profits of distributors' regulated (including network and regulated retail) and non-regulated (including contestable retail) businesses.

6.4 Network capital expenditure

In the 1999/2000 regulatory accounts, the DNSPs reported actual capital expenditure and projections for the following four years as shown in Table 6.6.

Table 6.6 Capital expenditure and capital contributions

$million (1999/2000$)	1999/00 Actual	2000/01 Forecast	2001/02 Forecast	2002/03 Forecast	2003/04 Forecast
Assets renewal	139.0	157.0	180.0	190.0	192.0
Assets addition	277.0	234.0	229.0	213.0	214.0
Reliability enhancement	29.0	35.0	33.0	29.0	30.0
Total gross capital expenditure	445.0	426.0	442.0	432.0	436.0
Gross capex projections per 1999 Network Determination	394.0	386.0	379.0	407.0	416.0
DNSPs' capex as a % of 1999 Determination projections	113%	110%	117%	106%	105%
Capital contributions	133.0	70.0	72.0	74.0	76.0
Capital contributions as % of assets addition	48%	30%	31%	35%	35%

Source: 1999/2000 Regulatory Accounts
Columns may not add due to rounding.

Industry capital expenditure in 1999/2000 totalled $445m, and was funded by capital contributions of $133m and internal funding of $312m. Of the total expenditure, 31 per cent was replacement capital expenditure, 62 per cent new capital expenditure and 7 per cent reliability enhancement expenditure.

Capital contributions received in 1999/2000 amounted to $133m. This was up from $83m (nominal) in 1998/99. Most of the increase is attributable to EnergyAustralia whose receipts increased by $38m in nominal terms in 1999/2000. The level of capital contributions received by the other DNSPs is roughly in line with the previous year. DNSPs expect the level of capital contributions to remain within the range of 30 per cent to 36 per cent of new capital expenditure in the next four years. Great Southern Energy however projects a higher proportion of its new capital expenditure being funded by capital contributions.

In aggregate, actual capital expenditure incurred by DNSPs in 1999/2000 is 13 per cent higher than that projected in the 1999 Network Determination.[19] In 1999/2000, EnergyAustralia's capital expenditure exceeded the 1999 Determination projection by 49 per cent or $73m. Major projects undertaken by EnergyAustralia in 1999/2000 included the Sydney CBD projects (including a new substation at Darling Harbour), development associated with the staging the Olympic games, projects at the Hunter Valley, augmentation on the Central Coast and a rebuild of Chatswood substation following a major fire.[20]

[19] Worley International was engaged to undertake a capital expenditure review of the DNSPs over the regulatory period from 1999/2000 to 2003/04 and the outcomes of the review were used in the December 1999 Electricity Distribution Networks Determination.

[20] EnergyAustralia, Annual Report for the financial year ended 30 June 2000.

6.5 Capital structure

Total debt allocated by the electricity businesses to the regulated networks decreased by $412m over the last four years and gearing fell significantly from 42 per cent in 1996/97 to 34 per cent in 1999/2000. The debt/EBITD ratio indicates that, industry-wide, the DNSPs' borrowings can be repaid in less than three years.

Gearing of the network businesses of EnergyAustralia and Integral Energy at 30 June 2000 was 40 per cent and 48 per cent respectively while that of the regional DNSPs ranged from 18 per cent for NorthPower to zero for AIEW. In comparison, the gearing of the electricity/gas/water sector in 2000 fiscal year averaged 50 per cent.[21]

6.5.1 Capital repatriation

In July 2001, $2,140m of capital was repatriated to the government shareholder to initiate a capital re-structure of the industry. Table 6.7 shows capital repaid by each of the electricity businesses.

Table 6.7 Capital repayments

	$ million
EnergyAustralia	1,130.0
Integral Energy	200.0
NorthPower	320.0
Great Southern Energy	300.0
Advance Energy	190.0
Aust Inland Energy & Water	-
DNSPs total	2,140.0

Source: 1999/2000 Annual Reports of NSW distributors.
Columns may not add due to rounding.

EnergyAustralia contributed nearly 50 per cent of the total repayment. AIEW was not required to make any repayment.

21 Business Review Weekly, 17 November 2000 issue, p 142.

APPENDIX 1 WHY THIS REPORT HAS BEEN PRODUCED

Currently, DNSPs provide information to the Tribunal under Rule 99/2, which is set out in the Tribunal's 1999 Network Determination.[22] The Tribunal made rule 99/2 as the jurisdictional regulator as a rule under clause 6.10.1(f) of the National Electricity Code. The Rule sets out the Tribunal's requirements in relation to pricing notification and information disclosure.

Currently a derogation under 9.16.3 of the Code exempts DNSPs from application of Part E of Chapter 6 of the Code. Part E Chapter 6 sets out a methodology for determining prices that apply to Prescribed Distribution Services[23] for distribution networks.

The Tribunal had (and still has) concerns about the workability of Part E. In particular, it saw the potential for pricing principles in Part E to produce outcomes that were in conflict with the objectives for regulating distribution pricing set out in clauses 6.10.2 and 6.10.3 of the Code. The NSW Government requested and was granted a derogation that exempted distributors in NSW from the application of Part E until 2002. The exemption allows the Tribunal to reinstate the application of Part E to distributors in NSW if it chooses to do so.

Clause 6.11(e) of Part E also allows the Tribunal, as Jurisdictional Regulator under the Code[24], to develop an alternative pricing methodology to the approach set out in Part E. Thus, the combination of these provisions enables the Tribunal to reinstate the application of Part E and then apply its own alternative methodology. The Tribunal has in fact done this, determining that prices for Prescribed Distribution Services will be determined based on Part E of Chapter 6 of the Code on and from 1 July 2001. At the same time, the Tribunal has developed its own alternative methodology entitled *Pricing Principles and Methodologies*[25] (PPM) for use in NSW in place of Part E.

The process will involve the revocation of rule 99/2 as of 1 July 2001, as the provisions in this rule are included in the PPM.

Currently, Rule 99/2 requires that DNSPs publish a pricing information package by 30 November each year.[26] This is also a requirement of the new PPM, however the information packages are now called Price and Service Reports.[27] The PPM also states that the Tribunal will publish a report summarising the price and service information submitted annually by the Distributors (s8.2).

22 IPART, *Regulation of New South Wales Electricity Distribution Networks, Determination and Rules under the National Electricity Code,* December 1999.

23 The Tribunal's 1999 Determination defines 'prescribed distribution services' as those service performed by each DNSP that are associated with or ancillary to access to that DNSP's network for the supply of electricity within that DNSP's service area, p vii.

24 See clause 9.16.3(b) of the Code.

25 IPART, *Regulation of New South Wales Electricity Distribution Networks – Pricing Principles and Methodologies for Prescribed Electricity Distribution Services – Developed pursuant to clause 6.11(e) of Part E, Chapter 6 of the Code,* March 2001.

26 Section 7.1. For 2000, the deadline was extended until 31 January 2001.

27 Schedule 3 of the PPM sets out the information required to be provided in the individual DNSP Price and Service Reports.

The Tribunal's *Price and Service Report* (PSR) is to include:

- a comparative summary of Prescribed Distribution Service prices and service performance levels; and
- a commentary on prices, pricing practices and information disclosure for all distributors.

The Requirements of Rule 99/2

The information disclosure requirements of Rule 99/2 can be summarised as follows:

By 30 November each year, DNSPs must publish a Pricing Information Package disclosing:

a) the methodology used for deriving prices for prescribed distribution services

b) medium term price directions for prices for prescribed distribution services.

The information disclosed must include, but is not limited to:

(a) a list of cost components for providing distribution services.

(b) a statement of the basis for asset valuation and calculating depreciation.

(c) an explanation/quantification of methodology to calculate prices from costs set out in (a) and (b).

(d) Forecast demand and load factors used in calculating charges.

(e) Performance data (against range of key indicators) including:

    - reliability and quality of service (from MEU reporting requirements)
    - indicators determined by Tribunal.

(f) Outline of future pricing strategies quantifying potential impact on prices.

(g) a summary of asset management and development plans, and potential impacts on pricing.

(h) a summary of industry or company developments which may affect pricing.

The secretariat further clarified these information requirements in an email to DNSPs in December 2000. The email outlined a proforma of tables and specific information which, if provided, would be considered to meet the requirements of rule 99/2. All DNSPs (with the exception of AIEW) have complied with the proforma.

The proforma contained specific tables to be completed relating to:

- operating and maintenance expenditure
- general operating statistics
- description of assets, depreciation and optimisation
- average prices and usage for network customers
- electricity demand growth
- existing and proposed prices for 'typical' customers
- capital expenditure projections.

The proforma also required information on:

- cost allocation methodology
- reliability of supply and quality of service
- partial productivity measures
- industry and company developments.

APPENDIX 2 ECONOMIC THEORY AND COST ALLOCATION METHODOLOGIES

Ideally, cost of service should be determined by recording and calculating the costs incurred. However, in industries such as the electricity distribution sector, costs are often shared and cannot be recorded precisely by service or customer. Where costs are aggregated, they must be allocated on an acceptable basis. Choosing an allocation methodology can be arbitrary, because the particular cost driver can be hard to identify.

Typical cost allocation methodologies include:

- *stand alone costs (SAC)* This allocation methodology assumes cost recovery based on the optimised stand alone assets required to provide distribution services. This allocation may apply to capital costs and / or operating costs.
- *fully distributed cost (FDC)* This allocation methodology assigns directly identifiable costs to components of the business (usually asset categories) along with a share of joint / common costs.
- *incremental cost* This is the additional cost of serving an additional customer and / or unit of production.

The economic theory of pricing sets bounds for charges, rather than specific levels. Outside these bounds, cross-subsidies or inefficiencies will result. The upper limit is the price above which a new entrant would find it attractive to enter the market in competition with the network. The lower limit is the price below which the network service provider suffers financially by serving the customer. Stand alone costs and incremental costs are common proxies for these subsidy-free upper and lower bounds.

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 Tribunal does not mandate a particular methodology. Rather, it allows DNSPs to select the approach they consider most appropriate to their circumstances.

Typically, discussion has focused on stand alone, incremental, and fully distributed cost allocation methodologies. However, there are other allocation methodologies. Cases can be made for basing revenue on a combination of methodologies.

Economic efficiency requires that usage prices recover at least avoidable (or incremental) costs. However, this can lead to a shortfall in revenue, since for most networks avoidable costs are less than average costs for most of the time. In considering options to recover average costs, minimising the impacts on consumption and investment decisions are important criteria.

Stand alone cost allocation may discourage growth and network utilisation where the resulting price is greater than the existing or potential user’s marginal valuation of the service. Despite this, stand alone allocation is consistent with economic principles as a means of defining a maximum price.

Allocating costs on a fully distributed basis involves an element of arbitrariness. However, it does provide for sharing costs across activities. The benefits of a shared system can be passed on to users when a fully distributed cost allocation results in lower prices. A fully distributed cost approach, through its identification of direct and indirect costs, is likely to assist in the recovery of average costs and thus meet the need for revenue sufficiency.

APPENDIX 3 AARR AND FINANCIAL PERFORMANCE

Table A3.1 Aggregate annual revenue requirement

$ million (nominal)	1999/00 actual	2000/01 forecast	2001/02 forecast	2002/03 forecast	2003/04 forecast
EnergyAustralia (note 1)	832.0	852.0	873.0	895.0	917.0
Integral Energy	484.7	499.2	520.4	531.7	543.5
NorthPower	205.7	216.5	228.1	240.2	253.1
Great Southern Energy	140.2	142.4	145.6	148.9	152.2
Advance Energy	89.1	93.3	97.8	102.5	107.5
Aust Inland Energy & Water	16.3	16.7	16.7	17.2	17.7

Source: Pricing Information Packages.

Note 1: Energy Australia's AARR includes revenue of its transmission assets.

Note 2: The AARR calculation is based on the methodology set out in the Tribunal's 1999 Network Determination, and consists of regulated base revenue plus TUOS and inter-distributor transfers. Unders/overs account adjustments are not included.

Table A3.2 Actual and projected energy sales (GWh)

	1997/98 actual	1998/99 actual	1999/00 actual	2000/01 forecast
EnergyAustralia				
actual/updated projection	22,151	22,978	24,364	24,973
projection in 1999 network determination	na	na	23,438	23,907
Integral Energy				
actual/updated projection	13,988	14,002	14,557	14,994
projection in 1999 network determination	na	na	14,492	14,999
NorthPower				
actual/updated projection	3,790	3,878	3,950	4,068
projection in 1999 network determination			3,994	4,114
Great Southern Energy				
actual/updated projection	3,006	2,999	3,082	3,104
projection in 1999 network determination			3,109	3,171
Advance Energy				
actual/updated projection	2,393	2,637	2,708	2,748
projection in 1999 network determination			2,703	2,770
Aust Inland Energy & Water				
actual/updated projection	400	418	413	np
projection in 1999 network determination			422	426

Sources: Regulatory Accounts, Pricing Information Packages and 1999 Network Determination

Note: Sales include estimated unread meter sales.

np = not provided

Table A3.3 Maximum demand (MW)

	1997/98 actual	1998/99 actual	1999/00 actual	2000/01 forecast
EnergyAustralia	4,481	4,618	4,983	5,055
Integral Energy	2,642	2,801	2,858	2,955
NorthPower	792	754	886	892
Great Southern Energy	558	561	578	585
Advance Energy	451	453	463	472
Aust Inland Energy & Water	np	59	57	60

Source: Pricing Information Packages.

np = not provided

Table A3.4 Number of customers ('000)

	1997/98 actual	1998/99 actual	1999/00 actual
EnergyAustralia			
actual	1,366	1,387	1,399
projection in 1999 network determination			1,407
Integral Energy			
actual	737	751	760
projection in 1999 network determination			764
NorthPower			
actual	352	358	366
projection in 1999 network determination			362
Great Southern Energy			
actual	226	228	231
projection in 1999 network determination			231
Advance Energy			
actual	118	120	120
projection in 1999 network determination			120
Aust Inland Energy & Water			
actual	22	21	21
projection in 1999 network determination			22

Sources: Regulatory Accounts and models used for 1999 Network Determination

Table A3.5 Actual and projected capital expenditure

$ million (1999/2000$)	1999/00 Actual	1999/00 IPART projected (note 1)	1999/00 % difference	2000/01 Agency projection	2000/01 IPART projected (note 1)	2000/01 % difference
EnergyAustralia	220.6	147.7	49%	163.5	156.5	4%
Integral Energy	94.5	105.1	-10%	95.1	83.5	14%
NorthPower	65.8	70.1	-6%	80.1	69.1	16%
Great Southern Energy	34.5	39.8	-13%	45.6	45.2	1%
Advance Energy	26.3	28.3	-7%	33.7	27.9	21%
Aust Inland Energy & Wate	3.7	3.2	14%	8.0	3.3	138%

Sources: 1999/2000 Regulatory Accounts and December 1999 Network Determination

Note 1. "IPART projected" refers to the expenditure projected in the 1999 Network Determination

APPENDIX 4 FINANCIAL PERFORMANCE OF THE SIX DNSPS

EnergyAustralia

Table A4.1 DNSP financial performance

(2000 $m)		1996/97 Actual (BV)	1997/98 Actual (BV)	1998/99 Actual (BV)	1999/00 Actual (BV)	1999/00 Actual (RAV)
Profit and Loss Statement						
Network use of system charge		861	846	844	833	833
Other operating income		35	38	24	25	25
Transmission charges paid		151	154	155	142	142
Operating and maintenance expenses		223	208	185	209	209
EBITD		526	514	528	506	506
Depreciation		169	171	170	166	182
EBIT		357	343	358	340	324
Net interest expense/(income)		134	123	87	77	77
Capital contributions		18	10	26	63	63
Balance sheet						
Cash and investments		247	337	396	126	126
Property plant and equipment		2,865	2,847	2,828	2,860	4,027
Total assets		3,398	3,537	3,576	3,329	4,497
Borrowings		1,347	1,354	1,336	1,044	1,044
Common equity		1,520	1,583	1,635	1,592	2,759
Total capitalisation (borrowings + equity)		2,867	2,937	2,971	2,636	3,803
Profitability						
EBITDA margin on sales (EBITDA/revenue)	%	58	59	58	59	59
EBIT margin on sales (EBIT/revenue)	%	39	40	40	40	38
NPAT/Shareholders Funds	%	11	11	11	13	7
EBIT/(Total Assets - cash & investments)	%	11	11	11	11	7
EBIT/(Borrowings + Equity)	%	12	12	12	13	9
Income protection						
Pretax interest coverage (EBIT/net interest)	Times	2.6	2.9	4.1	4.4	4.2
S&P indicative rating (Note 1)		BBB	A	AA	AA	AA
EBITD/Interest coverage	Times	3.9	4.2	6.1	6.6	6.6
Total debt/EBITD	Times	2.6	2.6	2.5	2.1	2.1
Capital structure						
Gearing (total debt/total capitalisation)	%	47	46	45	40	27
S&P indicative rating (Note 1)		AA	AA	AA	AA	AA

Source: Regulatory Accounts.
Columns may not add due to rounding.
BV = Book value of network assets and RAV = regulatory asset value as set out in the 1999 Network determination
Note 1: S&P ratings are indicative. Appendix 5 describes the Tribunal's methodology.

Since 1996/97:

- EnergyAustralia's network revenue has fallen by 3 per cent in real terms
- load has grown by 13 per cent
- operating costs improved 6 per cent in real terms
- EBITD and EBIT margin remained relatively stable at around 58 per cent to 59 per cent and 39 per cent to 40 per cent respectively
- gearing has fallen from 47 per cent to 40 per cent
- interest expenses have declined by 42.5 per cent in real terms

- in July 2000, gearing was lifted by additional borrowings of $1.13bn to fund the equity repayment to the government shareholder.

The table below compares the actual and the projected operating costs and capital expenditure in the 1999 network determination.

Table A4.2 Actual and projected operating costs and capital expenditure

$million (nominal)	1999/2000 Actual	1999/2000 IPART projected (note 1)	Actual exceeds projection
Operating costs	209	206	3
Gross capital expenditure-			
Renewal	73	57	16
Growth	129	76	53
Reliability	19	15	4
Total	221	148	73
Net capital expenditure (note 2)	158	127	31

Source: 1999/2000 Regulatory Accounts and 1999 Network determination
Columns may not add due to rounding
Note 1: 'IPART projected' refers to the expenditure projected in the 1999 Network Determination
Note 2: Net capital expenditure = gross capex less capital contributions

In 1999/2000:

- operating costs were 2 per cent higher than the 1999 network determination projections
- capital expenditure was 49 per cent higher than the 1999 network determination projections
- EnergyAustralia's 1999/2000 Annual Report states that major projects undertaken during the year include CBD and development associated with the staging the Olympic games, a new substation at Darling Harbour, projects at the Hunter Valley, augmentation on the Central Coast and a rebuild of Chatswood substation following a major fire.

Integral Energy

Table A4.3 DNSP financial performance

(2000 $m)		1996/97 Actual (BV)	1997/98 Actual (BV)	1998/99 Actual (BV)	1999/00 Actual (BV)	1999/00 Actual (RAV)
Profit and Loss Statement						
Network use of system charge		459	469	482	459	459
Other operating income		4	35	34	32	32
Transmission charges paid		91	89	86	88	88
Operating and maintenance expenses		140	179	158	160	160
EBITD		232	235	272	243	243
Depreciation		75	73	87	84	94
EBIT		157	162	185	159	149
Net interest expense/(income)		70	71	64	59	59
Capital contributions		19	17	21	25	25
Balance sheet						
Cash and investments		102	72	42	31	31
Property plant and equipment		1,354	1,332	1,493	1,429	1,800
Total assets		1,746	1,634	1,639	1,610	1,981
Borrowings		818	847	716	701	701
Common equity		866	736	637	759	1,130
Total capitalisation (borrowings + equity)		1,684	1,584	1,353	1,460	1,831
Profitability						
EBITDA margin on sales (EBITDA/revenue)	%	50	47	53	50	50
EBIT margin on sales (EBIT/revenue)	%	34	32	36	32	30
NPAT/Shareholders Funds	%	6	9	14	13	8
EBIT/(Total Assets - cash & investments)	%	10	10	12	10	8
EBIT/(Borrowings + Equity)	%	9	10	14	11	8
Income protection						
Pretax interest coverage (EBIT/net interest)	Times	2.2	2.3	2.9	2.8	2.6
S&P indicative rating (Note 1)		BBB	BBB	BBB	BBB	BBB
EBITD/Interest coverage	Times	3.3	3.3	4.2	4.2	4.2
Total debt/EBITD	Times	3.5	3.6	2.6	2.9	2.9
Capital structure						
Gearing (total debt/total capitalisation)	%	49	54	53	48	38
S&P indicative rating (Note 1)		A	BBB	BBB	A	AA

Source: Regulatory Accounts.
Columns may not add due to rounding.
BV = Book value of network assets and RAV = regulatory asset value as set out in the 1999 Network determination
Note 1: S&P ratings are indicative. Appendix 5 describes the Tribunal's methodology.

Since 1996/97:

- Integral Energy's network revenue has increased in 1997/98 and 1998/99 in real terms but returned to the 1996/97 level in 1999/2000
- load has increased by around 28 per cent
- operating costs have increased by 15 per cent in real terms
- EBITD margin ranged from 47 per cent to 53 per cent
- debts and interest expenses have reduced by 14 per cent and 18 per cent respectively in real terms
- gearing ranged 48 per cent to 54 per cent

- the additional borrowings taken up by Integral Energy in July 2000 to fund the $200m capital repayment to the government shareholder has reversed the downward trend of debt.

Table A4.4 compares the actual and projected operating costs and capital expenditure in the 1999 network determination.

Table A4.4 Actual and projected operating costs and capital expenditure

$million (nominal)	1999/2000 Actual	1999/2000 IPART projected (note 1)	Actual exceeds projection
Operating costs	160	157	3
Gross capital expenditure-			
Renewal	22	63	-41
Growth	72	41	31
Reliability	1	1	0
Total	95	105	-10
Net capital expenditure (note 2)	70	104	-34

Source: 1999/2000 Regulatory Accounts and 1999 Network determination
Columns may not add due to rounding
Note 1: ‘IPART projected’ refers to the expenditure projected in the 1999 Network Determination
Note 2: Net capital expenditure = gross capex less capital contributions

Compared with the projections in the 1999 Network Determination, the 1999/2000 operating costs were 2 per cent or $3m higher than projections but capital expenditure was 10 per cent or $10m lower than projections.

NorthPower

Table A4.5 DNSP financial performance

(2000 $m)		1996/97 Actual (BV)	1997/98 Actual (BV)	1998/99 Actual (BV)	1999/00 Actual (BV)	1999/00 Actual (RAV)
Profit and Loss Statement						
Network use of system charge		183	200	200	203	203
Other operating income		14	12	10	13	13
Transmission charges paid		43	46	50	43	43
Operating and maintenance expenses		80	85	80	74	74
EBITD		73	82	85	100	100
Depreciation		35	41	42	50	46
EBIT		38	40	43	50	54
Net interest expense/(income)		13	11	8	9	9
Capital contributions		18	19	16	23	23
Balance sheet						
Cash and investments		14	76	52	47	47
Property plant and equipment		519	618	915	916	947
Total assets		558	729	1,035	1,037	1,068
Borrowings		146	143	200	173	173
Common equity		359	539	722	766	796
Total capitalisation (borrowings + equity)		505	681	922	939	969
Profitability						
EBITDA margin on sales (EBITDA/revenue)	%	37	39	38	46	46
EBIT margin on sales (EBIT/revenue)	%	19	19	18	23	25
NPAT/Shareholders Funds	%	6	8	4	7	7
EBIT/(Total Assets - cash & investments)	%	7	6	4	5	5
EBIT/(Borrowings + Equity)	%	8	6	4	5	6
Income protection						
Pretax interest coverage (EBIT/net interest)	Times	3.0	3.7	4.6	5.7	6.1
S&P indicative rating (Note 1)		A	A	AA	AA	AA
EBITD/Interest coverage	Times	5.8	7.4	9.8	11.3	11.3
Total debt/EBITD	Times	2.0	1.7	2.5	1.7	1.7
Capital structure						
Gearing (total debt/total capitalisation)	%	29	21	22	18	18
S&P indicative rating (Note 1)		AA	AA	AA	AA	AA

Source: Regulatory Accounts.
Columns may not add due to rounding.
BV = Book value of network assets and RAV = regulatory asset value as set out in the 1999 Network determination
Note 1: S&P ratings are indicative. Appendix 5 describes the Tribunal's methodology.

Since 1996/97:

- NorthPower's network revenue has increased by 11 per cent in real terms
- operating costs have reduced by 7 per cent in real terms
- load growth was 9 per cent higher
- EBITD margin has improved from 37 per cent to 46 per cent
- gearing has declined to 18 per cent[28]
- to fund the capital repayment of $320m in July 2000 to the government shareholder, additional debts were taken up by NorthPower — as a result, gearing was raised to 53 per cent.

28 The decrease of gearing from 29 per cent to 18 per cent in 1999/2000 is mainly a result of the increased equity base boosted by the asset revaluation reserve in 1997/98.

Table A4.6 compares the actual and projected operating costs and capital expenditure in the 1999 network determination.

Table A4.6 Actual and projected operating costs and capital expenditure

$million (nominal)	1999/2000 Actual	1999/2000 IPART projected (note 1)	Actual exceeds projection
Operating costs	74	70	4
Gross capital expenditure-			
Renewal	16	13	3
Growth	45	45	0
Reliability	4	12	-8
Total	65	70	-5
Net capital expenditure (note 2)	43	63	-20

Source: 1999/2000 Regulatory Accounts and 1999 Network determination
Columns may not add due to rounding
Note 1: 'IPART projected' refers to the expenditure projected in the 1999 Network Determination
Note 2: Net capital expenditure = gross capex less capital contributions

Compared with the projections in the 1999 Network Determination, NorthPower's 1999/2000 operating costs exceeded projection by 5 per cent or $4m. Capital expenditure was 6 per cent or $5m lower than the projected amount.

Great Southern Energy

Table A4.7 DNSP financial performance

(2000 $m)		1996/97 Actual (BV)	1997/98 Actual (BV)	1998/99 Actual (BV)	1999/00 Actual (BV)	1999/00 Actual (RAV)
Profit and Loss Statement						
Network use of system charge		131	140	136	130	130
Other operating income		1	8	4	5	5
Transmission charges paid		35	26	28	27	27
Operating and maintenance expenses		55	45	53	50	50
EBITD		42	76	59	59	59
Depreciation		19	21	21	19	29
EBIT		23	56	38	39	30
Net interest expense/(income)		5	5	(1)	-	-
Capital contributions		11	11	13	13	13
Balance sheet						
Cash and investments		41	69	54	46	46
Property plant and equipment		406	407	407	407	516
Total assets		473	505	515	516	626
Borrowings		97	74	70	56	56
Common equity		327	386	400	412	521
Total capitalisation (borrowings + equity)		424	460	471	468	577
Profitability						
EBITDA margin on sales (EBITDA/revenue)	%	32	52	42	43	43
EBIT margin on sales (EBIT/revenue)	%	18	38	27	29	22
NPAT/Shareholders Funds	%	6	12	8	9	6
EBIT/(Total Assets - cash & investments)	%	5	13	8	8	5
EBIT/(Borrowings + Equity)	%	5	12	8	8	5
Income protection						
Pretax interest coverage (EBIT/net interest)	Times	5.0	10.9	- 59.3	151.7	113.8
S&P-US Utilities (1995)		AA	AA	>AA	>AA	>AA
EBITD/Interest coverage	Times	9.1	14.9	- 91.7	226.0	226.0
Total debt/EBITD	Times	2.3	1.0	1.2	1.0	1.0
Capital structure						
Gearing (total debt/total capitalisation)	%	23	16	15	12	10
S&P-US Utilities (1995)		AA	AA	AA	AA	AA

Source: Regulatory Accounts.
Columns may not add due to rounding.
BV = Book value of network assets and RAV = regulatory asset value as set out in the 1999 Network determination
Note 1: S&P ratings are indicative. Appendix 5 describes the Tribunal's methodology.

Since 1996/97:

- Great Southern Energy's network revenue has declined slightly in real terms
- load was 4 per cent higher
- operating costs has fallen by 9 per cent or $5m in real terms
- EBITD and EBIT margin have improved from 32 per cent and 18 per cent, to 43 per cent and 29 per cent respectively
- debt level has declined from $97m to $56m with gearing falling from 23 per cent to 12 per cent
- interest expenses have fallen by $5m in real terms
- the additional borrowings taken up in July 2000 to fund the $300m capital repayment has reversed the downward trend of gearing and interest payments.

Table A4.8 compares the actual and projected operating costs and capital expenditure in the 1999 network determination.

Table A4.8 Actual and projected operating costs and capital expenditure

$million (nominal)	1999/2000 Actual	1999/2000 IPART projected (note 1)	Actual exceeds projection
Operating costs	50	47	3
Gross capital expenditure-			
Renewal	15	15	0
Growth	13	17	-4
Reliability	6	8	-2
Total	34	40	-6
Net capital expenditure (note 2)	22	31	-9

Source: 1999/2000 Regulatory Accounts and 1999 Network determination
Columns may not add due to rounding
Note 1: 'IPART projected' refers to the expenditure projected in the 1999 Network Determination
Note 2: Net capital expenditure = gross capex less capital contributions

Compared with the projections in the 1999 Network Determination, operating costs in 1999/2000 were $3m or 4 per cent higher while capital expenditure by was $6m or 13 per cent lower than projection.

Advance Energy

Table A4.9 DNSP financial performance

(2000 $m)		1996/97 Actual (BV)	1997/98 Actual (BV)	1998/99 Actual (BV)	1999/00 Actual (BV)	1999/00 Actual (RAV)
Profit and Loss Statement						
Network use of system charge		83	88	87	88	88
Other operating income		-	6	9	6	6
Transmission charges paid		19	18	19	20	20
Operating and maintenance expenses		36	42	37	36	36
EBITD		28	29	32	39	39
Depreciation		11	10	13	16	19
EBIT		18	19	19	23	19
Net interest expense/(income)		3	2	3	1	1
Capital contributions		6	13	9	8	8
Balance sheet						
Cash and investments		-	17	12	0	-
Property plant and equipment		262	295	304	315	336
Total assets		276	343	341	338	360
Borrowings		32	42	44	48	45
Common equity		219	269	272	263	285
Total capitalisation (borrowings + equity)		252	311	316	312	330
Profitability						
EBITDA margin on sales (EBITDA/revenue)	%	34	31	33	42	41
EBIT margin on sales (EBIT/revenue)	%	21	21	20	24	21
NPAT/Shareholders Funds	%	11	11	11	11	6
EBIT/(Total Assets - cash & investments)	%	6	6	6	7	5
EBIT/(Borrowings + Equity)	%	7	6	6	7	6
Income protection						
Pretax interest coverage (EBIT/net interest)	times	5.5	9.2	5.5	14.4	14.4
S&P indicative rating (Note 1)		AA	AA	AA	AA	AA
EBITD/Interest coverage	times	8.9	13.9	9.2	24.6	24.6
Total debt/EBITD	times	1.2	1.4	1.4	1.2	1.2
Capital structure						
Gearing (total debt/total capitalisation)	%	13	13	14	16	14
S&P indicative rating (Note 1)		AA	AA	AA	AA	AA

Source: Regulatory Accounts.
Columns may not add due to rounding.
BV = Book value of network assets and RAV = regulatory asset value as set out in the 1999 Network determination
Note 1: S&P ratings are indicative. Appendix 5 describes the Tribunal's methodology.

Since 1996/97:

- Advance Energy's network revenue has remained constant in real terms
- operating costs have fallen by 2 per cent in real terms
- load has grown by 15 per cent
- EBITD and EBIT margin have improved from 34 per cent to 41 per cent and 21 per cent to 24 per cent respectively
- debt level was maintained at $42m to $45m with gearing ranging from 9 per cent to 15 per cent
- however, the capital re-structure in July 2000 increased the debt level by $190m and hence gearing.

Table A4.10 compares the actual and projected operating costs and capital expenditure in the 1999 network determination.

Table A4.10 Actual and projected operating costs and capital expenditure

$million (nominal)	1999/2000 Actual	1999/2000 IPART projected (note 1)	Actual exceeds projection
Operating costs	36	44	-8
Gross capital expenditure-			
Renewal	10	6	4
Growth	16	13	3
Reliability	-	9	-9
Total	26	28	-2
Net capital expenditure (note 2)	18	21	-3

Source: 1999/2000 Regulatory Accounts and 1999 Network determination
Columns may not add due to rounding
Note 1: 'IPART projected' refers to the expenditure projected in the 1999 Network Determination
Note 2: Net capital expenditure = gross capex less capital contributions

Compared with the projections in the 1999 Network Determination, operating costs were $8m or 18 per cent lower than projections. The reduction was largely attributable to increase in costs allocated to the unregulated businesses. This effectively reduced costs allocated to the regulated network business. Capital expenditure was $2m or 7 per cent lower than projections.

Australian Inland Energy & Water

Table A4.11 DNSP financial performance

(2000 $m)		1996/97 Actual (BV)	1997/98 Actual (BV)	1998/99 Actual (BV)	1999/00 Actual (BV)	1999/00 Actual (RAV)
Profit and Loss Statement						
Network use of system charge		13	14	15	14	14
Other operating income		1	6	5	4	4
Transmission charges paid		4	4	4	5	5
Operating and maintenance expenses		6	6	7	7	7
EBITD		4	9	9	7	7
Depreciation		2	2	2	2	3
EBIT		2	7	6	4	4
Net interest expense/(income)		-	-	(1)	(1)	(1)
Capital contributions		2	2	2	1	1
Balance sheet						
Cash and investments		11	17	18	18	18
Property plant and equipment		32	33	35	35	53
Total assets		50	56	58	59	77
Borrowings		-	-	-	-	-
Common equity		41	44	46	50	68
Total capitalisation (borrowings + equity)		41	44	46	50	68
Profitability						
EBITDA margin on sales (EBITDA/revenue)	%	27	47	45	35	35
EBIT margin on sales (EBIT/revenue)	%	14	37	34	23	22
NPAT/Shareholders Funds	%	14	14	16	10	7
EBIT/(Total Assets - cash & investments)	%	5	19	16	11	7
EBIT/(Borrowings + Equity)	%	5	16	14	9	6
Income protection						
Pretax interest coverage (EBIT/net interest)	times	No interest expenses over the period				
S&P indicative rating (Note 1)		>AA	>AA	>AA	>AA	>AA
EBITD/Interest coverage	times	No interest paid by AIE				
Total debt/EBITD	times	AIEW carries no debt.				
Capital structure						
Gearing (total debt/total capitalisation)	%	AIEW carries no debt.				
S&P indicative rating (Note 1)		>AA	>AA	>AA	>AA	>AA

Source: Regulatory Accounts.
Columns may not add due to rounding.
BV = Book value of network assets and RAV = regulatory asset value as set out in the 1999 Network determination
Note 1: S&P ratings are indicative. Appendix 5 describes the Tribunal's methodology.

Since 1996/97:

- AIEW's network revenue has remained at around $14m in real terms
- load has increased by 7 per cent
- operating costs have increased by 17 per cent in real terms
- EBITD and EBIT margin have increased by $3m and $2m respectively.[29]

Table A4.12 compares the actual and projected operating costs and capital expenditure in the 1999 network determination.

[29] This is largely attributable to increase in other operating income as shown in Table A3.6.

Table A4.12 Actual and projected operating costs and capital expenditure

$million (nominal)	1999/2000 Actual	1999/2000 IPART projected (note 1)	Actual exceeds projection
Operating costs	7.2	6.9	0.3
Gross capital expenditure-			
Renewal	1.0	0.3	0.7
Growth	1.9	2.3	-0.4
Reliability	0.8	0.6	0.2
Total	3.7	3.2	0.5
Net capital expenditure (note 2)	2.6	1.3	1.3

Source: 1999/2000 Regulatory Accounts and 1999 Network determination
Columns may not add due to rounding
Note 1: 'IPART projected' refers to the expenditure projected in the 1999 Network Determination
Note 2: Net capital expenditure = gross capex less capital contributions

Operating costs and capital expenditure incurred by AIEW were slightly higher than the projections in the 1999 Network Determination.

APPENDIX 5 STANDARD AND POOR'S INDICATIVE RATINGS

When setting prices, the Tribunal uses various techniques to examine the impacts of its decisions, one of these being indicators of financial performance, with a view to assessing the financial viability of the regulated business under different pricing outcomes.

A notional credit rating of the regulated business implied by certain financial ratios is calculated with the assistance of indicative ratios supplied by Standard and Poor's (S&P) ratings group, which are published from time to time. Those used in this report are taken from S&P's Corporate Finance Criteria for 1995. The ratios are indicative only and form part of the analysis undertaken by S&P in achieving an overall rating. The Tribunal uses the indicators in a similar manner, ie as part of the overall financial analysis of the regulated business.

The indicative ratings in Appendix 4 are based on only two of S&P's indicative ratios, namely pre tax interest coverage and gearing. S&P use many other ratios to determine an appropriate rating.

The actual rating process used by S&P is very broad, involving subjective judgements of industry risk and cost structures, not simply financial ratios. S&P use both qualitative and quantitative analyses in determining an entity's rating. The ratios used in the Tribunal's financial analysis are part of the latter. They should be used as a guide rather than as blanket reasons for giving a certain rating. S&P divide its analysis into:

- business risk - including market position, technology, efficiency and management capabilities, the prospects for growth in the industry, and vulnerability to technological changes or labour unrest or regulatory changes; and
- financial risk - looking at financial management policies, cash flow protection, capital structure and profitability.

S&P's analysis trades off between these two risks. In its guideline ratios, S&P provides financial indicator ranges for each of 'above average', 'average' and 'below average' business risk. During the analysis undertaken in 1999 as part of the determination process, the Tribunal decided that each of the regulated electricity network businesses had an 'above average' risk profile.

An acceptable range of ratios will differ from time to time according to the unique characteristics of the business. There will not be a perfect match between the ratios and the indicator rating; the ratios represent midpoints of ranges, and vary during an investment cycle. For this reason, the ratings indicated by the ratios for each of the regulated businesses based on individual years' financial results will not be the same as the actual rating given by S&P.

GLOSSARY

Asset Utilisation	The proportion of maximum capacity of an asset that is utilised.
CAIDI	Customer Average Interruption Duration Index
Contestable Customer	A customer who is able to choose a Retailer for the energy component of their electricity charges. Eligibility for being declared contestable is based on annual electricity consumption.
CRNP	Cost Reflective Network Price
Demand	Measurement of customer peak load taken as the average load over a half-hour period measured in kW or kVA.
Distribution network	Electricity network connecting the transmission system to customers. Voltages include 132,000 V down to typically 240 V at the customer's premise.
Distributor	A corporation constituted under the NSW Energy Services Corporation Act - includes network or wires function, and retail function.
DLF	Distribution Loss Factor – factor applied to customer's metered energy consumption to determine total purchases taking into account losses in the distribution network.
DNSP	Distribution Network Service Provider – network business of a distributor.
DUOS	Distribution Use of System Charges – Network tariffs designed to recover IPART determined network revenue
EDL	Electricity Distributor Levy – A levy collected from Contestable Customers by DNSP's on behalf of the State Government
Embedded Generator	Generator or co-generator that is connected to the distribution network instead of the transmission network.
GWh	Gigawatt hour = 1,000,000 kilowatt hours or 1,000 MWh, a measure of electrical energy
HV	High Voltage
IPART	Independent Pricing and Regulatory Tribunal
kV	kV = 1,000 Volts
kVA	kVA = 1,000 Volt-Amperes which is a measure of the apparent power flow which determines the amount of capacity required to supply the customer's load.
kW	kW = 1,000 Watts which is a measure of the actual power being consumed
Load Factor	Average load divided by the peak load

LV	Low Voltage
Loss Factors	A multiplier applied to a customers metered energy consumption to account for electrical losses incurred in transporting the energy from the point of purchase to the point of sale. Distribution loss factors (DLFs) are used to account for distribution losses whilst transmission loss factors (TLFs) account for transmission losses.
MEU	Ministry of Energy and Utilities
MWh	Megawatt Hour = 1,000 kilowatt hours, measure of electrical energy
NEC	National Electricity Code - market rules governing the operation of the National Electricity Market, which commenced in December 1998.
NECA	National Electricity Code Authority – the body charged with responsibility for administering the National Electricity Code.
NEMMCO	National Electricity Market Management Company, responsible for the implementation of the Code and the day to day operation of the National Electricity Market.
Network Charges	Charges applied by the Network Business for use of the transmission and distribution system in the supply of electricity to the customer's premises. Network charges also include Recoverable Works Charges, Miscellaneous Charges, and Monopoly charges associated with contestable works.
NUOS	Access charge for use of the transmission, sub transmission, and/or distribution system for the supply of electricity to the customer's premises (NUOS = TUOS + DUOS)
Off-Peak Period	All times other than Peak and Shoulder Periods on working weekdays and all times on weekends and public holidays.
Pass Through Costs	Costs that are not allowed for in normal operating and maintenance costs that are permitted by IPART to be passed on to customers. These costs are added to the allowable base revenue set down by IPART and are recovered through network prices.
Peak Period	Generally periods 7:00 – 9:00 am and 5:00 – 8:00 pm on working weekdays.
Power Factor	A measure of the real power in kW divided by the apparent power in kVA. The optimum power factor is 1.0 where the real power equals the apparent power.
PSR	Price and Service Report
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

Revenue Cap	The maximum allowable revenue applicable to DNSPs' businesses.
SCADA	Supervisory Control And Data Acquisition: A computerised control system that enables remote control and monitoring of the electrical network.
Shoulder Period	Generally the periods 9:00 am – 5:00 pm and 8:00 – 10:00 pm on working weekdays.
System Losses	Electrical losses due to resistance in the conductors used to carry electricity.
TLF	Transmission Loss Factor – factor applied to customer's metered energy consumption to determine total purchases taking into account losses in the transmission network.
TOU	Time of Use - refers to tariff structure with separate energy charges over Peak, Shoulder, and Off-Peak time periods.
TransGrid	NSW transmission authority provider of transmission services for conveyance of electricity from NSW generators to bulk supply points throughout NorthPower's service area.
Transmission Charges/TUOS	Transmission Use of System Charge - component of network charge which covers use of the transmission network.
Transmission network	Electricity network owned and operated by TransGrid, operating at voltages between 132,000 V and 500,000 V and connecting the generators to the distribution network.