Electricity Prices and Cost Factors

Staff Research Paper

Chris Sayers
Dianne Shields

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Publications Inquiries:
Media and Publications
Productivity Commission
Locked Bag 2 Collins Street East
Melbourne VIC 8003

Tel: (03) 9653 2244
Fax: (03) 9653 2303
Email: maps@pc.gov.au

General Inquiries:
Tel: (03) 9653 2100 or (02) 6240 3200

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Foreword

This staff research paper had its origins in a project to benchmark electricity prices internationally, as part of the Commission's series of International Benchmarking studies. The usefulness of benchmarking as a guide to relative performance depends critically on an ability to compare like with like, or to make allowance for differences in operating environment that may be outside a utility's control. This proved not to be possible in this case. Despite considerable effort by the research team and consultants, and attempts to engage the local industry in this matter, the role of key cost factors in observed price differences could not be reliably ascertained.

Given the importance of this industry to the community and to Australia's economic performance, it is important that further research on cost factors be undertaken — particularly if, as the industry argues, price regulation is to move in the direction of more light-handed productivity-based methodologies. This study, by identifying the key cost factors and their relative significance, provides some guidance as to where further information and research is most needed.

The study benefited from input by members of the industry, both here and overseas, who either assisted the Commission directly or provided information to its consultant, UMS Group Australia Pty Ltd. The Commission is also grateful for the feedback from participants at a workshop held to discuss a work-in-progress draft, which led to a number of improvements to the study.

This study was undertaken in the Commission's Economic Infrastructure Branch. Apart from the principal authors, contributors to the project included Meron Desta, Mark Fitzgibbon, Sally Harvey, Kai Swoboda, Leon Trethowan and Andrew Welsh.

Gary Banks
Chairman

August 2001

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Abbreviations

ABARE	Australian Bureau Of Agriculture and Resource Economics
ABS	Australian Bureau of Statistics
AC	Alternating Current
ACCC	Australian Competition and Consumer Commission
ACSR	Aluminium conductor, steel reinforced
AEP	American Electric Power
AGC	Automatic Generation Control
ASAI	Average System Availability Index
BIE	Bureau of Industry Economics
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CBD	Central Business District
CSO	Community Service Obligation
Dayton P&L	Dayton Power & Light
DB	Distribution Business
DLF	Distribution Loss Factor
DOE(NSW)	Department of Energy (NSW)
DOE(US)	Department of Energy (US)
DSM	Demand-side management
DUOS	Distribution Use of System

EA	Electricity Association
EEI	Edison Electric Institute
EIA(US)	Energy Information Administration (US)
EPACT	Energy Policy Act 1992 (US)
ESAA	Electricity Supply Association of Australia
ESI	Electricity Supply Industry
ETEF	Electricity Tariff Equalisation Fund (NSW)
FERC	Federal Energy Regulatory Commission (US)
FOR	Forced Outage Rate
FPA	Federal Power Act
FPC	Federal Power Commission
GSE	Great Southern Energy
GST	Goods and Services Tax
GW	GigaWatt
GWh	GigaWatt hour
Kansas CP&L	Kansas City Power & Light
kV	KiloVolt
kW	KiloWatt
kWh	KiloWatt hour
IEA	International Energy Agency
IPARC	Independent Pricing and Regulatory Commission (ACT)
IPART	Independent Pricing and Regulatory Tribunal (NSW)
IOU	Investor-owned utility (US)

LOLE	Loss of Load Expected
MAIFI	Momentary Average Interruption Frequency Index
MORI	Market and Opinion Research International
MW	MegaWatt
MWh	MegaWatt hour
NECA	National Electricity Code Administrator
NEM	National Electricity Market (Australia)
NEMMCO	National Electricity Market Management Company Limited
NSP	Network Service Provider
OECD	Organisation for Economic Co-operation and Development
OFFER	Office of Electricity Regulation (UK)
Omaha PPD	Omaha Public Power District
ORG(Vic)	Victorian Office of the Regulator-General
PC	Productivity Commission
PPP	Purchasing Power Parity
PPUC	Pennsylvania Public Utilities Commission
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act 1978 (US)
QEISTF	Queensland Electricity Industry Structure Task Force
REC	Regulated energy cost
RMS	Root Mean Squared
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

SAIIR	South Australian Independent Industry Regulator
SARFI	System Average Root Mean Squared Variation Frequency Index
SCADA	Supervisory control and data acquisition
SCNPMGTE	Steering Committee on National Performance Monitoring of Government Trading Enterprises
SFE	Sydney Futures Exchange
TFP	Total factor productivity
TUOS	Transmission Use of System
UPS	Un-interruptible Power Supply
VAT	Value-Added Tax
VoLL	Value of Lost Load

Key messages

- The original purpose of this study was to benchmark electricity prices internationally. However, it was not possible to achieve this aim because sufficient information could not be obtained on the range of costs that have to be taken into account to infer relative performance from prices.
- Prices, and the cost factors influencing prices, were examined for a range of utilities in Australia, Canada, Germany, Israel and the United States. The utilities were chosen to minimise differences in operating characteristics.

Prices

- There were significant differences in the prices paid for electricity as at October 2000 (relative to the prices of other goods and services) for residential and business customers across and among the studied Australian and overseas utilities.
- The observed price differences tended to increase with annual consumption levels.
- The price differences were not affected greatly by the assumptions used to calculate and compare prices.

Quality of service

- There are differences in supply reliability among the utilities studied. These differences highlight the importance of taking the associated cost difference into account when comparing performance, particularly between urban and rural-based utilities.

Cost factors

- There are some important cost factors over which utilities have no control. These must be taken into account for any conclusions to be drawn about performance relativities.
- Certain generation and distribution costs may be the most significant explanators of price differences. Scale diseconomies at the distribution level appear to increase costs for some Australian utilities, particularly those in rural areas. For other utilities, generation fuel costs may also result in higher costs.
- There is insufficient publicly available information and understanding of cost drivers to quantify the cost differences.
- The size of the cost differences and their potential significance indicates that the factors affecting costs warrant further research.

Overview

The original purpose of this study was to benchmark electricity prices paid by customers in Australia against those in other countries. Service quality and cost factors outside the control of suppliers were examined in an attempt to explain differences in price relativities among countries.

It was not possible to achieve this aim because information could not be obtained on the costs that have to be taken into account to infer relative performance from prices. However, the identification of cost factors and their relative significance provides useful insights into where further research is required to improve the robustness of benchmarking and productivity comparisons more generally.

Scope

The prices paid by Australian electricity customers were compared with those paid by customers of electricity utilities in Canada, Germany, Israel and the United States. The utilities were chosen to minimise differences in operating characteristics. All predominantly use coal for generation.

Some of the smaller distributors in the larger Australian States, the hydro-electric-based supplier in Tasmania and the oil and gas-based supplier in the Northern Territory were omitted to make the study manageable.

Approach

Indexes of electricity prices were estimated by costing consumption bundles for three types of customer — residential, small to medium business and large business. The bundles were selected from a larger number of consumption bundles used by the Electricity Supply Association of Australia for price comparisons of Australian suppliers.

The average price paid for each bundle was calculated using the tariff schedules available from each utility. For customers purchasing electricity at negotiated rates, estimates of typical contract prices were used to cost the bundles. The price comparisons relate to October 2000.

Prices were compared on a purchasing power parity (PPP) exchange rate basis. When electricity prices are converted using PPPs, the resultant index is the ratio of electricity prices to the price of other goods and services in that country. This index indicates whether Australian customers pay more for electricity relative to other goods and services than their counterparts in other countries.

Only cost factors with a *direct* impact upon costs were considered. Government interventions that indirectly influence prices — for example, the productive efficiency effects of competition policy or incentive regulation — were not examined.

The cost factors included those associated with each utility's operating environment, production economies, energy losses and government imposts and interventions. There appears to be no other existing work in Australia that has similarly aimed at systematically analysing and quantifying the impact of cost drivers on relative costs.

Prices and performance

The performance of Australian electricity utilities relative to those overseas cannot be inferred from the price comparisons presented in this report. Only after prices had been adjusted to reflect differences in cost, could performance differences be inferred from any remaining price difference.

There was a wide dispersion in the prices paid by customers across the studied utilities. There were also large differences in prices among the Australian utilities. This dispersion was observed for each of the customer categories examined.

Prima facie, the size of the observed price differences are evidence of the existence of factors affecting costs and hence prices. The net cost of these factors appear be greater for Australian utilities. Further, the price differences among utilities in Australia suggest that costs are greater for rural-based than urban utilities.

The price differences tended to increase as annual consumption rose. Overseas utility tariffs incorporate block charges and demand charges. This leads to significant reductions in price as annual consumption rises.

Prices were not greatly affected by the assumptions used to calculate them. Sensitivity analyses of the results using different levels of peak demand and varying load factor produced only minor changes in the relative rankings of Australian and overseas utilities.

Quality of service

Quality of service varies across all of the studied utilities. However, the comparisons did not reveal a pattern of overseas utilities having levels of quality of service that are systematically different from those in Australia.

Cost outcomes to consumers due to departures from an efficient quality of service–price tradeoff are likely to be minor. Surveys reveal that consumers are not prepared to pay significantly more for improvements to quality of service.

Quality of service is to some extent a legacy of history and hence largely outside the control of current managers. Only incremental changes are likely to be possible in the short-run, with minor consequences for prices. Nevertheless, comparisons of performance between urban and rural-based utilities should only be undertaken on the basis of prices adjusted for the different costs associated with their quality of service differences.

Cost factors

The factors considered in this study span the entire industry. However, it is the factors associated with the generation and distribution of electricity that are probably of most significance in explaining price differences. Generation and distribution costs represent the largest proportion (around 80 per cent) of total industry costs. Consequently, differences in these costs between the studied utilities can have significant implications for the prices paid by customers.

There are many factors that affect the capital and operating costs of electricity utilities over which they have no control. Despite considerable efforts to obtain it, a lack of comprehensive and reliable data for the studied utilities prevented the quantification of the cost factors. However, the likely significance in general terms that each factor has for the measured price relativities can be inferred.

Variations in economies arising from output density (average consumption per customer) and customer density (customers per kilometre of network) — both of which are outside the control of any utility — could explain a large proportion of the price differences observed between utilities. In particular, there are statistically significant negative correlations between the rankings of the utilities by prices and their rankings by output density. For other utilities, generation fuel costs may also result in higher costs.

The size of the cost differences and the potential significance of industry performance for Australia’s competitiveness and the wellbeing of household customers indicate that a greater understanding of costs is required. Further work needs to be undertaken to establish the significance of each of the factors identified and analysed in this study.

1 Introduction

This study began as an international benchmarking report that was part of a program of research into the performance of Australia's economic infrastructure industries. International benchmarking studies of the waterfront, telecommunications and drinking water industries have preceded this study.

In undertaking this study, the aim was to improve upon earlier studies of the electricity industry by systematically examining the costs over which the industry has no control, but which, nonetheless, have implications for the prices that customers pay.[1] However, insufficient publicly-available data and a lack of cooperation from some of the studied utilities have prevented the analysis and understanding of these cost drivers. Consequently, an assessment of the performance of Australia's electricity utilities against those overseas could not be made.

In view of this, this study provides information on the likely drivers of cost in the electricity industry and suggests which may be of most significance in explaining prices. It is important that further research be conducted on these factors, particularly given their significance for regulatory and policy reforms.

1.1 Objective

The aim of this study was to analyse the relative size of cost factors outside the control of the industry in Australia against those in other countries. This was achieved by:

- collecting electricity prices for residential and business users in Australia with those overseas; and
- analysing cost information for a range of factors over which the industry has no control that may explain observed prices.

1 The industry was previously studied by the Bureau of Industry Economics (BIE) in 1996, using mainly 1994 data. At that time, Australian prices were compared against other countries using aggregate data published by the International Energy Agency (IEA).

1.2 Purpose

Two key questions were addressed:

- *Do Australian residential and business consumers pay more or less for electricity than their overseas counterparts relative to the price paid for other goods and services?*
- *To what extent are differences in price relativities among countries due to cost factors outside the control of suppliers in the short-run, or due to differences in quality and to internal factors such as productivity, that are influenced by the market and regulatory environment?*

In Australia and other countries, the efficiency of the electricity industry is important because electricity is a major input into economic activity as well as being a major activity in its own right. The Australian electricity supply industry had total assets of $74.8 billion, revenue of over $21.6 billion and employed 35 000 people in 1997-98 (ESAA 2000b).

As a business input, cheaper electricity has the potential to increase the competitiveness of a range of economic activities. Lower electricity prices are also of direct benefit to final consumers.

1.3 Scope

The prices paid by customers that purchase electricity at scheduled tariffs were calculated, together with the prices paid by those customers that negotiate prices. Prices are reported for a range of residential, small to medium and large business customers.

Service quality was examined, however, the scope of service quality reporting was limited by the availability of consistent data to elements of service quality such as the duration and frequency of outages.

Information on the regulatory environment has been presented where necessary to provide context. However, current Australian and overseas policies were not evaluated.

Initially, the following overseas distributor suppliers were selected for inclusion in this study:

- Bewag, Germany
- Cegedel, Luxembourg
- Dayton Power and Light, Ohio USA

- Empire District Electric Co., Missouri USA
- Israel Electric Corporation, Israel
- Kansas City Power and Light, Kansas USA
- Kentucky Utilities Co., Kentucky USA
- Mid American Energy Co., Iowa USA
- NS Power, Nova Scotia Canada
- Okinawa Electric Power Co., Japan
- Omaha Public Power District, Nebraska USA
- Pennsylvania Power Co., Pennsylvania USA
- Western Resources, Kansas USA (formerly Kansas Gas and Electric).

However, the tariff schedules for Cegedel in Luxembourg or Okinawa Electric Power Co in Japan could not be obtained. Consequently, these two utilities were excluded.

The countries and utilities were chosen with the following criteria in mind:

- electricity is mainly generated by coal-fired plants;
- a load factor in the range of around 50 to 75 per cent;
- a peak load no higher than Australia's largest distributor;
- customer load densities that are indicative of a mix of residential and business customers;
- a satisfactory financial rate of return;
- socio-economic environment comparable to Australia; and
- availability of data.

The characteristics of the overseas utilities included are provided in table 1.1.

The Australian retail suppliers that were included are:

- Energy Australia, New South Wales
- Integral Energy, New South Wales
- Great Southern Energy, New South Wales
- United Energy, Victoria
- Citipower, Victoria
- Powercor, Victoria
- Energex, Queensland
- Western Power Corporation, Western Australia
- AGL, South Australia
- ACTEW, Australian Capital Territory

Table 1.1 **Overseas utility characteristics, October 2000**

Utility[a,b]	*Customers*	*Electricity output*[c]		*Coal-based generation*	*Supply area*	*Length of line*		*Privately owned?*
		Generated	*Purchased*			*Transmission*	*Distribution*	
	number	GWh/yr	GWh/yr	per cent of total output	square km	km	km	yes/no
Bewag, Berlin, Germany[d]	4 693 626	11 365	3456	63	891	**n.a.**	39 591	yes
Dayton P&L, Ohio, USA[e]	495 000	16 728	1523	99	15 540	1363	n.a.	yes
Empire District, Missouri, USA[f]	146 000	2984	1686	82	25 900	2045	9984	yes
Israel Electric	1 999 000	36 378	0	73	20 770	4665	18 993	no
Kansas CP&L, Kansas USA	463 000	15 600[g]	**n.a.**	70	**n.a.**	2736	19 795	yes
Kentucky Utilities, Kentucky, USA	487 000	20 700	1560	98	**n.a.**	6803	23 527	yes
Mid American Energy, Iowa, USA[i]	666 000[j]	20 000	5000	80	**n.a.**	6800	47 000	yes

(Continued on next page)

Table 1.1(continued) **Overseas utility characteristics, October 2000**

Utility[a,b]	*Customers*	*Electricity output*[c]		*Coal-based generation*	*Supply area*	*Length of line*		*Privately owned?*
		Generated	*Purchased*			*Transmission*	*Distribution*	
	number	GWh/yr	GWh/yr	per cent of total output	square km	km	km	yes/no
NS Power, Canada	440 000	9954	411	70	n.a.	5250	24 000	yes
Omaha PPD, Nebraska, USA	287 000	8535	2190	80	13 000	21 000[h]	**n.a.**	no
Penn Power, Pennsylvania, USA[h]	134 000	5049[g]	**n.a.**	61	3885	1048	8341	yes
Western Resources, Kansas USA	294 000	23 000[g]	**n.a.**	75	69 930	44 643[h]	**n.a.**	yes

n.a. Not available. [a] All of the overseas utilities are vertically-integrated. [b] Most of the overseas utilities have no competitive segments in that generation, transmission, distribution and retailing are not open to competition. The exceptions are Bewag and Pennsylvania Power. [c] Output figures differ slightly from figures for electricity sales because of losses. [d] Transmission and distribution are the only regulated segments. Generation and retailing are open to competition. [e] Effective 1 January, 2001, electric generation, aggregation, power marketing and power brokerage services supplied to retail customers in Ohio will be deemed competitive and will not be subject to supervision and regulation by the Public Utilities Commission of Ohio. Existing limitations on an electric public utility's ownership rights of a non-public utility were eliminated. All earnings obligations, restrictions or caps imposed on an electricity utility in a Public Utilities Commission of Ohio order became void as of the effective date of the Legislation. [f] Primary market is located in South-western Missouri but also includes smaller areas of South-eastern Kansas, North-eastern Oklahoma and North-western Arkansas. [g] Total amount sold. Split between generation and purchased power not available. [h] Total length of network as breakdown between transmission and distribution is unavailable. [i] No segments of the Iowa or South Dakota markets are open to full competition. Deregulation of generation and retailing is being implemented in Illinios, with full competition due by May 2002. The transmission and distribution of electricity remains regulated under federal and state laws. [j] Mid American Energy's primary market is Iowa which represents 89 per cent Mid American Energy's electricity sales. Mid American also transmits, distributes and retails electricity into Illinios (approx 10 per cent of sales) and South Dakota (approx. 1 per cent of sales). [l] Customer choice is being phased in over three years with 66 per cent of each customer class able to choose alternative suppliers of generation by 2 January, 2000, and all remaining customers having choice as of 1 January, 2001. Under the plan, Penn Power continues to deliver power to homes and businesses through its transmission and distribution systems, which remain regulated by the Pennsylvania Public Utilities Commission.

Sources: Dayton P&L (2000); Empire District Electric Company (2000); First Energy Corporation (2000); Israel Electric Corporation (1998); Kansas G&E (2000); Kansas CP&L (2000); LG&E (2000); Mid American Energy Company (2001) pers. comm, 26 February 2001; Mid-American Holdings Company (2000); NS Power Holdings Inc (2000); Omaha PPD (2000); Western Resources (2000 & 2001).

Some of the smaller distributors in the larger States were omitted to make the study manageable. The hydroelectric suppliers in Tasmania and the oil and gas supplier in the Northern Territory were also omitted. Their inclusion would have substantially increased the number of overseas distributors that would need to have been included.

1.4 Approach

The approach was to compare whether Australian customers pay more or less for electricity relative to the cost of other goods and services than their overseas counterparts.

Consumption bundles

Indexes of electricity prices were estimated by costing consumption bundles for each of three categories of customer — residential, small to medium and large business.[2] The bundles are described in chapters 3, 4 and 5 respectively.

The bundles were selected from the consumption bundles used by the Electricity Supply Association of Australia (ESAA) for price comparisons of Australian suppliers. However, only approximately one-quarter were considered necessary for the purpose of making robust international comparisons. They were chosen to provide information on how prices differ according to the demand characteristics represented by the consumption bundles. For example, different proportions of off-peak consumption have been included to determine its effect on electricity prices.

Using consumption bundles avoids the theoretical problems of an overall price index such as the revenue yield used by the IEA. The revenue yield approach is where average prices are calculated by dividing total revenue received from all customers by the total number of units of electricity sold.

The difficulty with the revenue yield approach is that it is relatively easy for the calculated average price to differ between two countries because of differences in demand patterns, even though the tariff or price structure is the same. This is less likely to occur in this study with its more segmented approach to price comparisons using consumption bundles.

2 The term ‘consumption bundle’ is used here to describe all the defining elements of usage that affect a customer’s overall bill. These elements may include volume consumed, the proportion of off-peak usage and peak load.

Prices

The consumption bundles were costed (in cents per kiloWatt hour) using the tariff or price available to eligible customers with the consumption characteristics defined in each bundle. Where customers with a particular bundle were eligible to receive electricity under more than one tariff structure, the tariff structure that resulted in the lowest cost was used.

For customers purchasing electricity at negotiated — commercial-in-confidence — rates, estimates of typical contract prices were used to cost the bundles. The estimates were principally derived from commercially available information on these prices. However, information on spot and futures market prices was used to infer actual prices having regard for the premium paid for revenue certainty achieved by hedging and entering into long-term contracts.

Price comparisons

Prices were converted to a common currency using purchasing power parity (PPP) exchange rates.[3] This approach is consistent with that used by the OECD and the IEA. However, market exchange rate comparisons are also made to test the sensitivity of price relativities to exchange rate assumptions.

Consistent with the objectives of the study, all taxes were included in prices. This includes business customers, notwithstanding that indirect taxes like the GST are rebated to businesses using electricity as an input in their production activities. Taxes are included in business prices because they are eventually embodied in the final product prices paid by customers — increasing prices and reducing customer demand for their products and services.[4]

Relative productivity was not examined. While relative productivity is important, previous attempts at productivity analyses by the Independent Pricing and Regulatory Tribunal of New South Wales and others, have identified problems with

3 PPP exchange rates are currency conversions that reflect the real purchasing power of a national currency. When PPP exchange rates are used to convert prices in a common currency, the resultant price is the amount paid for electricity relative to that paid for other goods and services. The prices are thereby adjusted to take into account the general level of prices in each country. See chapter 3 for a more complete explanation.

4 Derived demand for electricity as an input into final products is also reduced as a result of the tax. Therefore, it is wrong to think of GST as only having an effect at the retail level — its effects are felt right through the value added chain, regardless of where the tax happens to be collected.

the underlying assumptions and data that compromise the usefulness of the results.[5] Further, outcomes for customers depend on the effectiveness of regulation aimed at preventing monopoly pricing, as well as the productivity of industry participants.

Factors affecting prices

The utilities included in the study were chosen to maximise comparability. However, there are a large number of external factors outside the control of industry participants affecting cost and, hence, price and service differences.[6] Accordingly, information was collected to identify and adjust for cost differences caused by external factors outside the control of the industry.

The *external factors* that are relevant to the electricity supply industry fall into the following broad categories:

- operating environment;
- economies in production;
- energy losses; and
- government interventions such as industry-specific taxes, environmental regulation and economic regulation.

Residual price differences after external factors are accounted for are explained by internal factor differences. Internal factors include all factors affecting business performance that are amenable to management control.

There was no attempt to investigate the impact of differences in *internal factors* under the control of management such as productive efficiency. They are specific to each supplier and best left to internal investigation. However, the existence of any residual price differences indicates that there may be scope for productivity improvement, more rigorous price regulation or both.

By describing the external factors in this report and where possible estimating their magnitude and relative impact on prices, it is hoped that the study will better inform policy makers about the scope for price reductions. Analysis of these factors should

5 Relative price differences may reflect differences in relative productivity arising from internal managerial performance. However, relative prices can also reflect differences in costs outside the control of the supplier, differences in economy-wide productivity, the extent to which any price-setting ability is constrained by competitive conditions and effective regulation.

6 Government price regulators can also influence prices — their determinations reflecting a range of internal, external and market factors.

also produce a better understanding of international price comparisons more generally.

The UMS Group Australia Pty Ltd. assisted with the identification and collection of information that was used to assess the cost impact of these external factors. Specifically UMS were required to:

1. Examine the factors outside the control of suppliers identified by the Commission and advise if there are additional factors that affect costs and hence prices;
2. Provide advice on how such factors affect costs by identifying the key cost drivers;
3. Recommend ways the Commission could quantify the cost impact of differences in the cost drivers for each factor across the studied utilities. Alternatively, where the cost impact of the factors across suppliers cannot be reliably determined or there is a dearth of information, recommend a case study that would allow the Commission to illustrate the significance of differences in cost drivers for each of the factors affecting costs;
4. Collect information for all of the Australian and overseas utilities named in the study proposal to enable the Commission to quantify or illustrate the cost impacts of differences in cost drivers using a quantification method or case study acceptable to the Commission;
5. Where factors affect just one part of the supply chain, collect cost structure information that will allow their impact on overall supply costs to be determined;
6. Collect data on how each utility has performed according to the generally accepted service quality measures;
7. Provide any relevant contextual information that affects price comparisons, such as regulations applying to all electricity suppliers in a country as well as those that are relevant to particular utilities; and
8. Provide full bibliographic details for the sources of all information and data referred to in the consultant’s report to the Commission.

Cost structures were used to gauge the influence of factors affecting one part of the industry on overall costs and final prices. In order to do this, the industry was ‘unpacked’ into its component parts — generation, transmission, distribution and retailing.

Consultation

The Commission consulted widely with government, industry and others during development of the study approach. Advice was obtained from the ESAA which was particularly helpful at the commencement of the study.

A list of the organisations and individuals contacted by the Commission in the course of the study is provided in appendix A.

An open invitation was also issued for those with an interest in the study to comment and provide information that would assist the Commission. A study outline was posted on the Commission's web page as a guide. Industry participants were also invited to notify the Commission of people or organisations that should be contacted.

Throughout the study, comment on the accuracy of factual information on regulatory arrangements was obtained from the industry, both in Australia and overseas. When approached, all of those who participated in the study co-operated constructively.

A workshop was held on 9 July 2001 on the study methodology, the presentation of results and their interpretation. The comments provided by participants and the insights gained from the discussion were used to finalise this report. A list of the workshop participants is provided in appendix A.

Refereeing

Drafts of report chapters containing technical commentary were refereed by Associate Professor Hugh Outhred of the University of NSW.

1.5 Report outline

The electricity supply industry is described in chapter 2. Specifically the nature of electricity as an economic good is discussed along with the economics of supply. Price formation is described as background to the price comparisons in the following chapters. As an adjunct to this, the factors that affect costs and prices identified in this study are listed and explained.

In chapters 3, 4 and 5 unadjusted prices are presented for residential, small to medium business and large contestable customers respectively. The results are examined with a view to determining whether price relativities are robust across a broad range of customers and customer demands. Sensitivity analyses of the assumptions are undertaken for this purpose.

The influence of service quality on cost is described in chapter 6. Information on the level of service provided by the utilities studied is also presented. Finally, the likely impact on costs of any difference in service level is discussed.

Information on the influence of cost factors outside the control of the industry is provided in chapter 7. Where possible, a basis for quantifying the effect of differences in these cost drivers is identified.

2 Electricity supply and pricing

Electricity supply has a key role in the economy, both as an essential service to customers and as an intermediate input into other industries. As such, reliable supply and efficient pricing contribute to overall economic performance.

Complexities in delivering electricity derive from its unique characteristics as a source of energy (see appendix B for more detail on the delivery of electricity). In delivering electricity many factors must be taken into account, some of which are out of the control of the service providers. The characteristics and factors peculiar to an electricity network will influence its price to final customers.

2.1 Economic significance

Electricity supply is a significant activity in Australia, with an annual turnover of $21.6 billion in 1997-98 (ABS 1999). In 1998-99, over 180 000GWh of electricity was produced with total consumption estimated to be 161 762GWh (ESAA 2000b).[1] The generating capacity of the Australian electricity industry in 1997-98 was estimated at almost 40 000MW (ABARE 2000).

In 1997-98, the Australian electricity industry had total assets valued at $74.8 billion and employed approximately 35 000 people (ABS 1999).

The total number of customers in Australia is approximately 8.5 million, of which 85 per cent are residential. However, residential customers accounted for only 30 per cent of all electricity consumed in 1997-98, with average residential consumption per customer of approximately 2500kWh (ABS 1999).

According to the *ABS Household Expenditure Survey*, fuel and power expenditure per week per household for 1998-99 was $17.87 (ABS 2000a). Electricity accounts for 72 per cent of this amount or approximately $13 per week (ABS 1999).

1 Consumption is less than production because of electrical losses at various points between production and final consumption.

Contribution of electricity to the Australian economy

Electricity supply accounts for approximately 1.4 per cent of Gross Domestic Product (ABS 2000a).

The overall contribution of electricity supply to economic activity can be examined from the perspective of electricity consumed as an intermediate input. As an input to production, the cost of electricity has an impact upon the competitiveness of firms, both directly and indirectly, when electricity is 'embodied' in other inputs used in production. The electricity industry contributed approximately 2 per cent ($9.4 billion) of total intermediate expenditure by Australian industry in 1998-99 (ABS 2000b).

For most sectors, electricity makes up a small proportion of total intermediate goods and services used in production (see box 2.1 and figure 2.1 for the ten highest uses).

Box 2.1 **Input–output tables — the electricity sector[a]**

Input–output data provide a snapshot of the linkages between the micro units within an economy. They are a disaggregated version of the national income and expenditure accounts.

By using the information in these tables, it is possible to ascertain the input that electricity has in the production of the goods and services relative to other inputs listed in the tables, and what inputs other sectors provide in the production of electricity.

All of the 106 goods and services listed in the input–output tables use electricity as an input.

These input–output figures are an average for the defined classification of the sector. Some specific industries within these classified sectors, such as aluminium smelting, have a much higher dependency on electricity.

a 1996–97 was the latest available data from the ABS at the time of publication.

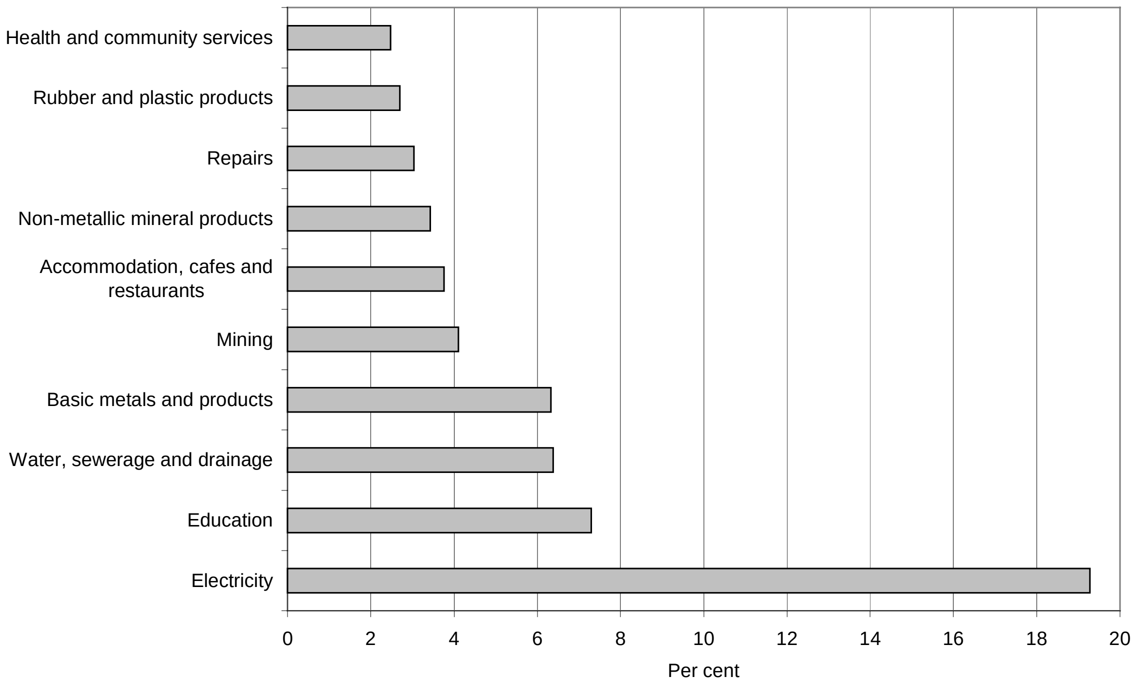
Source: ABS (2001).

The electricity supply industry is an exception, consuming a large proportion of its own product as an intermediate input (19.3 per cent).[2] The only other input that has

2 The relatively large amount of electricity used by the electricity industry as an intermediate input, 19.3 per cent as recorded by the ABS in input–output tables, is an artefact of the national accounts. In 1998-99, approximately 18 000GWh more electricity was produced than consumed because of losses (ESAA 2000b). Since this amount of electricity was not consumed by other industries, and yet the nature of the input–output accounts requires it to be allocated, it is attributed to the electricity industry and recorded as an intermediate input (ABS, pers. comm., 7 March 2001).

a greater contribution to electricity production is coal, oil and gas that account for 32.6 per cent (ABS 2001).

Figure 2.1 **Electricity supply expenditure as a proportion of total expenditure by industry, 1996-97**



Data source: ABS (2001).

Given that the electricity sector has the highest proportion of electricity as an input, it is not surprising that it also accounts for the greatest proportion of consumption of total electricity output used by an industry sector at 13.6 per cent (see figure 2.2) (ABS 2001).

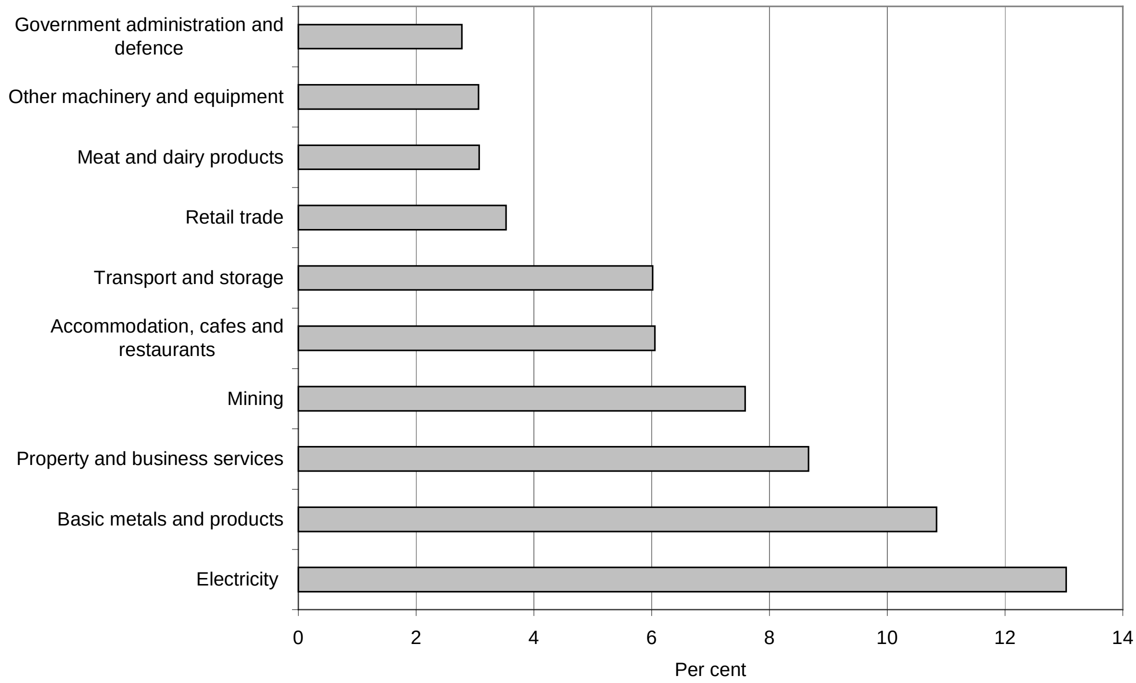
The basic metals and products sector is the second largest user of electricity, consuming 10.8 per cent of output.[3]

The estimates of electricity consumption provided by the ABS are lower than those reported by the Australian Bureau of Resource and Agricultural Economics (ABARE). ABARE estimate that the manufacturing sector accounted for 34.1 per cent of consumption in 1997-98 (ABARE 2000). This data included estimates of consumption by industrial customers of independent power producers,

3 The input–output industry classification Basic Metals and Products encompasses Iron and Steel, Basic Non-Ferrous Metal and Non-Ferrous Basic Metal Product Manufacturing.

cogenerators and private producers in remote locations not covered by the input-output analysis.[4]

Figure 2.2 **Proportion of electricity output used by industry, 1996-97**



Data source: ABS (2001).

2.2 Electricity supply

The electricity supply industry (ESI) can be divided into generation, transmission, distribution and retail sectors. This separation applies regardless of the market structure that the ESI operates under.

Electricity is generated from naturally occurring primary energy sources, such as coal, gas and oil as well as taking advantage of the potential energy of water and geothermal steam. It is transferred from generation plants along an interconnected system of high voltage power lines to near the point of final demand. The transmission voltage is then reduced before delivering it to final customers over a distribution network. Retail companies sell electricity to an end user based on their metered consumption.

4 A cogenerator can be defined as an entity owning a generation facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating or cooling purposes.

In Australia and some other countries, electricity was supplied by publicly-owned, vertically integrated monopolies operating in a regulated market.[5] In a vertically integrated structure, the entity that owned the generation plant also owned the network and was the sole supplier in a given area.

Governments in Australia have encouraged structural separation of vertically integrated utilities, in an effort to introduce competition among competitive elements (see box 2.2). However, non-competitive elements, such as transmission and distribution networks, remain subject to regulation.[6]

Similar approaches to industry restructuring and the encouragement of competition have been undertaken in the US (see box 2.3).

Characteristics of electricity as a good

Electricity has a number of distinguishing characteristics, namely:

Essential service — many of the conveniences and equipment of twenty-first century life require electricity to function (for example, artificial respirators, personal computers and household appliances).

Derived demand — where electricity is not required in itself as a good but as an input to production of the goods and services consumed as a final product. This results in demand that is not as price sensitive as the demand it is derived from.

Volatility of demand — demand varies over each day and over the year. Demand may also fluctuate randomly in a way that is unpredictable and outside the forecast demand patterns.

Homogeneity — electricity is a homogeneous commodity that is not easily amenable to product or brand differentiation. It can be supplied at differing voltages, frequencies and reliability levels, but the source of its production is immaterial to its form. Although customers cannot physically distinguish electricity from different sources, some are willing to pay higher prices for electricity generated in environmentally-preferred plants (for example, those using renewable sources of energy such as solar and wind).

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5 A vertically integrated supplier undertook the generation, transmission, distribution, wholesaling, retailing and other activities involved in the supply of electricity.

6 Regulated National Electricity Market interconnectors may be subject to competitive pressures from unregulated interconnectors. ‘Directlink’, an interconnector between Queensland and New South Wales, is not regulated.

Complex flow — it is not possible to define a specific flow of electricity to particular supply points. The laws of physics determine flows of electricity, whereby it follows along the path of least resistance. Consequently, the operation of the electricity system in a given service area can affect and be affected by operations in other service areas.

Non-storability — electricity cannot be stored cost effectively. Therefore, electricity production must be synchronized to match changes in demand instantaneously, balancing the system in real time. Unlike other industries, net demand is not affected by inventories held at points along the supply chain.

Near-continuous consumption — in most cases, customers do not generally consider the price of electricity before they consume it, but receive a bill for a period of consumption. Further, there are transaction costs associated with monitoring prices continuously. Consequently, most customers pay a bill that reflects the average cost over the period, often over the year. This militates against the use of short-term demand management options based on cost-reflective prices.

Although value-in-use varies with customer type and the time of day, this is not necessarily revealed in the price customers pay. For example, air conditioning units are typically billed under tariffs that do not reflect the associated costs of supply. Demand is not as responsive to price as it might be if customer prices reflected market prices at any given time and customers adjusted their consumption instantaneously — that is, demand is artificially inelastic.

With near continuous consumption and non-storability of electricity, sufficient 'quick start' capacity must be held in reserve to meet demand peaks. This capacity is very expensive to operate, resulting in average costs increasing non-linearly with capacity. Given the artificially low responsiveness to prices that reflect the high cost of satisfying all demands, average costs rise rapidly. This can lead to extreme price volatility at the wholesale level if prices are determined by an auctioning system.

Box 2.2 **Reform in the Australian electricity industry**

Australian Governments introduced significant changes to the electricity sector progressively through the 1990s. The intention was to create a competitive national market. The changes involved three key elements:

Structural Change — the structural separation of vertically integrated entities into competitive (retail and generation) and monopoly (generally network) components.

Access to monopoly infrastructure — a legislated regime allowing access by third parties to the transmission and distribution wires.

Improved market reach — one national (east coast) market was to be formed, with stronger interconnections, detailed rules and a range of relevant institutions created.

In general, the reform process has consisted of the following steps being taken by State and Territory Governments:

- Competitive sourcing of generation capacity based on merit order dispatch of individual generators;
- Open access to the eastern and southern Australian grid through establishment of an interstate electricity transmission network;
- Free trade in bulk electricity for private generating companies, public utilities and private and public electricity customers;
- Disaggregation of generation into separate companies to ensure adequate competition between generators;
- Establishment of the transmission and distribution systems as separate companies, regulated as monopolies by a regulator who is independent of Government;
- Ring fencing of retailing from the distribution network where these activities have remained in a single company;
- Introduction of competition in generation and retail supply through the removal of legal barriers to competition;
- Separation of wholesale electricity tariffs into separate charges for electricity consumed (determined by competition) and the use of electricity networks (regulated); and
- Some states have also privatised various corporatised elements of the industry as part of their reform.

Sources: NEMMCO (1999); Port Jackson Partners (2000).

Box 2.3 **Measures to increase competition in the US**

The US electricity industry structure is currently in transition from vertically integrated regional monopolies to one of widespread competition in all industry segments. This trend began in 1978, when the *Public Utility Regulatory Policies Act 1978* (PURPA) allowed (non-utility) generators that are not vertically integrated into transmission and distribution to enter the wholesale market.

Non-utility generators produce power for their own use or sell wholesale to integrated utilities. They do not retail electricity nor possess transmission facilities. They have regulated access to transmission facilities and, by 1998, they accounted for 13 per cent of US electricity generation.

There are approximately 3000 electricity utilities in the US, with about 800 generators and more than 2000 acting as distribution utilities only. In 1998, approximately 77 per cent of the demand for electricity was generated by 239 large investor-owned utilities (IOUs) — unlike Australia, where with the exception of electricity utilities in Victoria, utilities are mainly government-owned.

Competition in wholesale power sales received a boost in 1992 when the *Energy Policy Act 1992* (EPACT) expanded the Federal Energy Regulatory Commission's (FERC's) authority to order vertically integrated IOUs to allow generators not connected to the transmission grid (for example, supplying power directly to a factory) to gain access to the grid, facilitating the sale of energy on the open market. Approximately half of all electricity generated in the US is now purchased (or traded) in the wholesale market before being sold to ultimate customers.

FERC has long believed that revised arrangements for transmission and interstate power trade (Federal responsibilities) were a necessary condition for greater retail competition (a matter for State control). Moves to introduce retail competition have started in many States and as at 1 July 2000, 24 States had passed laws or regulatory orders to that effect. However, the utilities in this study are located in jurisdictions that generally have not implemented competition as at the date of the price comparisons.

At a pragmatic level, progress on introducing retail competition has been linked to the differences in price levels among the US States:

> A number of States have played an active role in promoting retail competition in the electric power industry. Relatively high cost States have been in the forefront of enacting legislation or making rules to allow retail competition and encourage customers to shop for their power suppliers. Other States such as Kentucky and Idaho, whose rates are among the lowest in the country, are not moving as quickly. A recent report issued by Kentucky's Special Task Force [of the Kentucky General Assembly] on Electricity Restructuring found no compelling reason for Kentucky to move quickly to restructuring its electric power industry. (DOE(US) 2000, p. ix).

Sources: FERC (2000); DOE(US) (2000).

Economic characteristics of electricity supply

The characteristics of electricity as a good, along with the following production characteristics, determine the overall economies of electricity supply.

Capital intensive — supplying electricity is capital intensive. There are economies in constructing large scale generating capacity (*indivisibilities*). Consequently, investment can result in an overhang of capacity. Projected returns must be attractive enough to encourage investment with prices set above the short-run marginal cost of production to recover the fixed costs.

Risk — price and quantity are highly variable because of the unpredictability of aggregate demand and supply. There are availability risks that generating plant will fail and require unscheduled maintenance, or if generators are able to game the market by taking capacity offline to increase prices and profitability. There are also risks attached to the price of fuel, a major input.

Shared assets — given the nature of network design and the complexity of load flows, many of the assets are 'used' by many customers as it would be uneconomical to duplicate them. The allocation of costs common to shared assets is a key pricing issue.

Sunk costs — the assets required are durable, long-lived, immovable and come in large discrete units. The assets have few if any alternative uses and once in place they are largely sunk.

Production externalities — as part of the process of converting fuel into electricity there are production externalities, where the emissions or waste produced in electricity generation have an adverse impact on the surrounding environment and population. In relation to air pollution, governments are attempting to internalise some of the external costs being placed on the environment by introducing emission standards, pollution taxes and tradeable emission permits.

Generation

There are economies of scale in electricity generation.[7] Economies of scale for generating units and generating plants are attributed to such factors as:

- lesser leakages and power losses obtained in larger generating units;

7 Scale economies exist for a firm producing a single output if, when output doubles, the total cost of production less than doubles.

- operating and maintenance costs that increase less than proportionally with unit size;
- scale economies in coal-handling facilities and generating units;
- non-proportionalities between plant capacity and site costs;
- economies in transmission; and
- optimal levels of reserve margins (Burness et al 1985).

The generation output level at which scale economies are exhausted, or the point of minimum efficient scale of operation, has been declining in recent decades with the introduction of new technologies that are efficient at smaller scale. This phenomenon is less apparent for transmission and distribution. However, decisions concerning what type of generation plant to install and how to operate it, influence the price of electricity, as discussed later under residual factors in section 2.5 of this chapter.

Generators are required to match supply to demand in real time because of the non-storable and continuous consumption characteristics of electricity. Baseload generators are run all the time, whereas quick-start generators are used for spinning reserve and to handle short-term peak loads.[8]

Quick-start generators, with lower construction costs than baseload plants, are used to meet unexpected periods of high demand. They are only run intermittently and are relatively expensive to operate compared with baseload generators. Thus, costs of supplying electricity to satisfy short-run peak loads within a network increase rapidly, as the quantity demanded increases and quick-start generators are progressively engaged.

The cost of supplying electricity in a network increases as output approaches capacity as illustrated in figure 2.3. Baseload generators operate most of the time and their costs represent the ‘floor’ price of electricity. As demand increases and quick-start generators are engaged, prices jump as a reflection of increased costs. This is represented by the step form of the supply curve.

The additional unit cost incurred with quick-start generators relative to baseload generators, results from lower thermal efficiency. Further, there is an opportunity cost of idle capital because they are only used intermittently.

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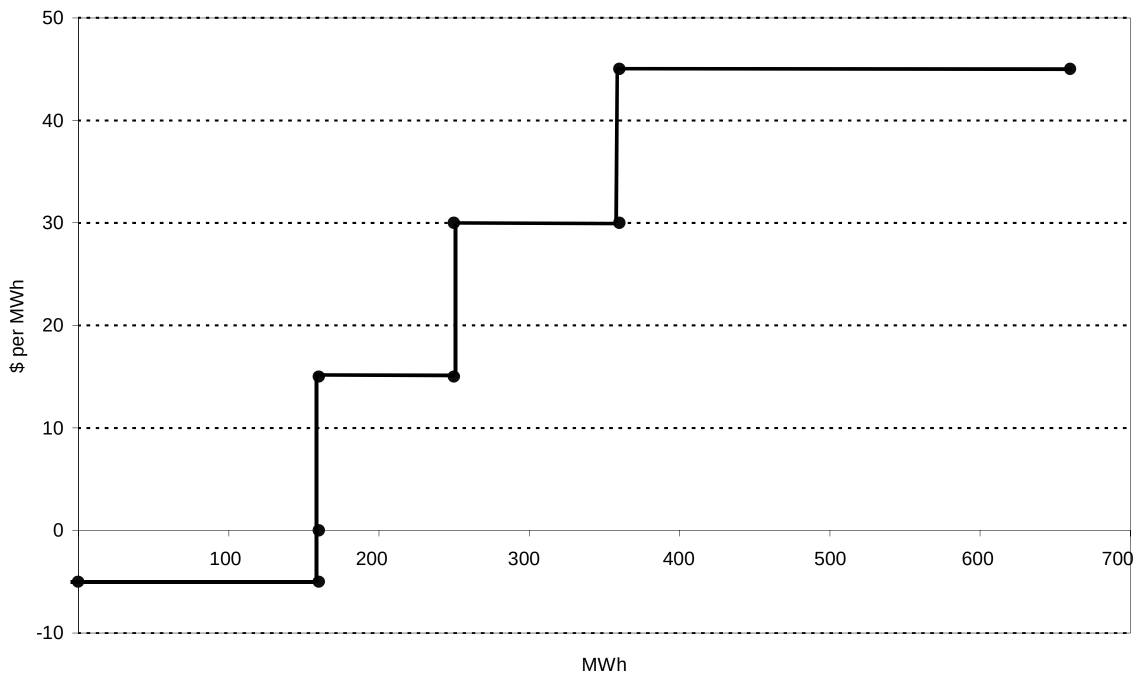
8 Spinning reserve is the provision of unloaded generation capacity synchronised to the system. It is capacity in excess of the quantity required to serve current and anticipated demand. Spinning reserve is available immediately to serve load increases.

Baseload generators are very costly to take off line and restart. Consequently, they are sometimes run at a loss rather than being shut down and re-started. This situation is illustrated in figure 2.3, where there is a negative price for initial levels of electricity supply.

Figure 2.3 **Electricity supply curve for an aggregate pool with merit order dispatch**



Data source: NEMMCO (1999).

Baseload generators are often located close to the source of fuel, sometimes far away from their customer base, despite the losses incurred in transmitting electricity over large distances. It is more efficient overall to avoid transportation costs of raw materials.

All electricity systems need reserve capacity to cope with unplanned equipment outages and unexpected demand increases. Under normal operating conditions excess capacity, termed spinning reserve, is required to cover unexpectedly high demand peaks and unplanned generator outages. Generation utilities can minimise costs of carrying reserve capacity by sharing reserve, the extent of which depends on how the power system is interconnected.

Small generators that are close to customers' premises (embedded generation), may also be connected to distribution networks. Embedded generation has the potential to supply electricity to the network and therefore compete with network service providers (by reducing the need for network services) as well as with other generators connected to the transmission network.

Transmission

Investment and supply augmentation in transmission requires long lead times because of its nature and the expense involved. Because of this 'lumpy' investment pattern, transmission capacity tends to increase in steps rather than continuously expanding to match demand increases. Therefore, future demand patterns must be taken into consideration in providing a reliable and sufficient transmission service.

The diseconomies associated with duplicating transmission networks are so great that it is typically efficient to have only one network in a given area. Because of the access issues that transmission networks raise, transmission network service providers have either been government-owned or heavily regulated to mitigate abuses of market power.

More recently, governments have regulated transmission businesses to facilitate access by third party generators. The aim has been to provide for entry and encourage competition in both generation and distribution.

Distribution

Distribution networks have very long economic lives. Consequently, as population and demand increases, the system is expanded incrementally. This situation poses challenges when integrating new technologies into existing distribution systems.

The location of customers throughout a utility's service territory impacts on the assets that the utility must invest in to deliver its services. This in turn affects the costs incurred in delivering those services (for example, underground cables versus overhead lines).

With a very high proportion of fixed assets, there are economies of density and output in distribution. The average cost of servicing a particular area declines as the number of customers in that area using existing assets increases, or as the average load drawn by those customers increases.

Energy losses over distribution lines are also dependent on customer density (because this contributes to resistance in delivery), with losses increasing as customer density decreases in remote and rural communities. Thus, customer mix and the quantities of electricity consumed have a bearing on the unit cost of supply.

Retail

There are believed to be economies of scope in retailing electricity. Economies of scope arise when a firm can produce any combination of multiple outputs more cheaply than could independent specialised firms, each producing a single product.[9]

Retail companies can exploit economies of scope by offering metering, billing, customer service, power merchandising, energy equipment sales, finance, operations and maintenance and energy management services.

Regulation

The level to which competition in supplying residential customers has developed in the overseas countries varies. However, even in liberalised markets, governments or regulators monitor the prices that utilities charge customers.

Transmission and distribution network service providers are usually regulated as natural monopolies by governments. Where suppliers are vertically integrated, the business as a whole is regulated.

Regulators remain responsible for regulating the distribution and supply functions because demand is relatively inelastic and creates scope for monopoly pricing where customers are franchised to a retailer. Electricity price regulation for these retail customers often takes the form of legislated tariff schedules.

Regulated tariff schedules are used as a price cap to safeguard against monopoly pricing and sometimes to ensure equity and affordability for some customers. In Australia, the chief distinction between contestable and non-contestable customers is that a component of the tariff is unregulated for contestable customers. The regulated charges, relating to transmission and distribution, make up a larger proportion of the overall supply cost to small and rural customers.

In Australia, regulating the transmission network is the responsibility of the Australian Competition and Consumer Commission (ACCC), as the national regulator of access regimes. The ACCC also authorises the market operation rules by which the Australian National Electricity Market (NEM) operates. State regulators monitor and set prices for distribution Network Service Providers.

9 The degree of economies of scope is measured by the percentage reduction in costs that occurs when one business produces two products, relative to the cost of two firms producing each product individually.

In the US, for example, the FERC is responsible for regulation of transmission, and the State utility commissions tend to be responsible for distribution and retail prices (see table 2.1).

2.3 Price formation

The way prices are formed and their structure varies by customer type. Customers fall into two broad categories, those that buy directly from the generators or wholesalers and those that buy from retailers.

In Australia and some other countries, customers are also categorised as contestable and non-contestable. Contestable customers have a choice of who they buy their electricity from (see box 2.4). Retail customers can be both contestable or non-contestable, depending on whether the area they live in has been franchised to a retailer.

Box 2.4 **Contestability of customers**

Contestable customers are able to choose who they purchase their electricity from. The electricity prices paid by contestable customers are determined as a result of negotiation with their supplier.

A retailer buys wholesale electricity on behalf of franchise customers (non-contestable customers whose prices are regulated) and may also supply non-franchise customers (contestable customers). Contestable end use customers may negotiate directly with generators for electricity in some circumstances. It is proposed that all customers will be made contestable in Australia in NEM jurisdictions in the next few years.

Non-contestable customers receive services from a distributor located within the geographical franchise supply region.

Table 2.1: Overseas utilities — price regulation arrangements as at October 2000

Utility	*Arrangements*
Dayton Power and Light, Ohio, USA	The Company's sales of electricity to retail customers are subject to rate regulation by the Public Utilities Commission of Ohio and various municipalities. The Company's wholesale electric rates to municipal corporations and other distributors of electric energy are subject to regulation by FERC under the *Federal Power Act*. Legislation introducing competition has recently been introduced but was not applicable in October 2000.
Empire District Electric Co., Missouri, USA	Retail price regulation is implemented by the State Regulatory Commissions of the States in which Empire operates. At Federal level, the FERC is trying to encourage competition in all the States by means of regulations establishing open access transmission tariffs that require utilities to offer all wholesale buyers and sellers the same transmission services as the utilities enjoy themselves.
Israel Electric Corporation	Prices are determined by the Public Utilities Authority — Electricity.
Kansas CP&L, Kansas, USA	KCP&L is subject to the jurisdiction of the Kansas Corporation Commission which has general regulatory authority over retail rates. The FERC has authority over wholesale sales of electricity.
Kentucky Utilities, Kentucky, USA	The utility is regulated by the Kentucky Public Service Commission and the FERC.
Mid American Energy, Iowa, USA[a]	In Iowa, Mid American Energy's retail rates are regulated by the Iowa Utilities Board. Restructuring Bills have been introduced into the State legislature, but legislation has not proceeded.
NS Power, Nova Scotia, Canada	Rate structures are subject to approval by the Utility and Review Board. There has been no restructuring to introduce competition.
Omaha Public Power District, Nebraska, USA	Regulatory control is by the Nebraska Public Service Commission and the FERC.
Pennsylvania Power Co., Pennsylvania, USA	Subject to rate regulation by the Pennsylvania Public Utilities Commission. In addition, Pennsylvania Power is also subject to the jurisdiction of the FERC, which has authority over wholesale sales of electricity. Competition is being introduced, beginning on 1 January 2001.
Western Resources, Kansas, USA	Western Resources is also regulated by the Kansas Corporation Commission which has general regulatory authority over retail rates. Western Resources is subject to the jurisdiction of the FERC with respect to wholesale sales of electricity.

[a] Mid American Energy's primary market is Iowa which represents 89 per cent of Mid American Energy's electricity sales.

Sources: Compiled by Productivity Commission based on Annual Reports, DOE(US) (2000); FERC (2000).

Price to wholesale customers

Wholesale customers usually buy from the generator. The price for electricity at source is negotiated by parties directly and settled through contract. In the Australian NEM, generators sell their electricity into a pool and customers buy from the pool at the prevailing market price (see box 2.5).[10] However, they may trade financial instrument contracts with one or more generators or other parties.

Participants in electricity markets include:

- generators with significant capacity;
- customers with their own generating capacity (cogenerators); and
- contestable customers (electricity retailers and other large customers).

In the centrally coordinated dispatch process, electricity supply and demand requirements are continually balanced by scheduling generators to produce sufficient electricity to meet customer demand. Generators compete by providing dispatch offers (prices for different levels of generation) to the National Electricity Market Management Company Limited. (NEMMCO). Market customers may submit dispatch bids, comprising prices and associated quantities of demand they wish to be scheduled in the dispatch process. NEMMCO dispatches the scheduled generation with the objective of minimising the cost of meeting electricity demand based on the offer and bid prices.

The spot price, also called the settlement price, is calculated by NEMMCO using the price offers and demand bids made by Scheduled Generators and Market Customers in the pool (see figure 2.4).[11]

10 The wholesale electricity market uses the concept of a pool where all the electricity output from generators is centrally pooled and scheduled to meet electricity demand. In Australia, the pool does not currently include Tasmania, Western Australia and the Northern Territory.

11 A scheduled generator is one who is required to have its output scheduled by NEMMCO.

Box 2.5 Institutions of the Australian National Electricity Market and their roles

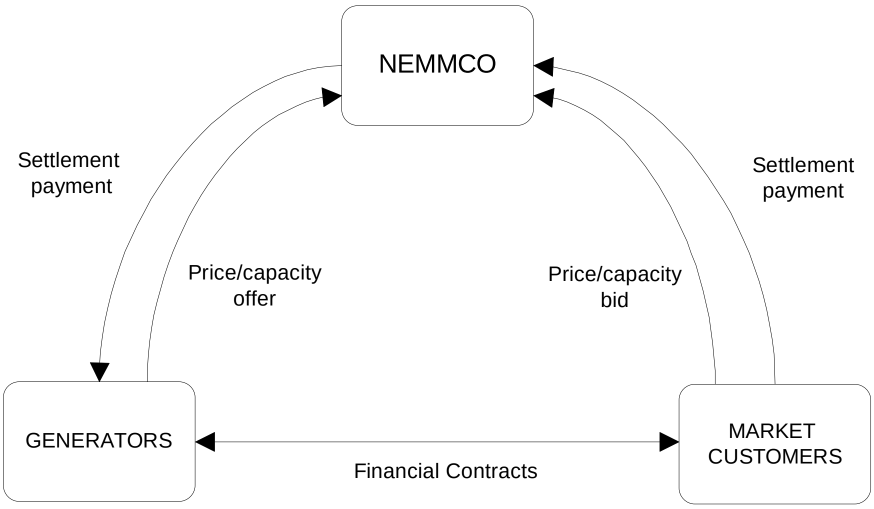
The NEM is a pool administered by the National Electricity Code Administrator (NECA) and operated by NEMMCO for trading electricity between generators and contestable customers in the Australian Capital Territory, New South Wales, Queensland, South Australia and Victoria, with open access to electricity networks. The roles of the institutions involved with the running of the NEM include:

- The *National Electricity Code* (the Code) sets out market rules, procedures and the information systems which support them, that form the NEM.
- The *NECA* administers the Code, manages the Code change process and enforces the Code.
- As the market operator, *NEMMCO* is responsible for managing the wholesale electricity market, balancing supply and demand of electricity according to the rules and procedures described in the Code, and facilitating the billing and settlement of all spot market transactions.
- The *ACCC* assesses applications for authorisation of potentially anti-competitive conduct by industry participants, changes to the Code and regulates the revenues of transmission network service providers.

Participating generators supply electricity to the pool under a dispatch process prescribed in the Code and managed by NEMMCO. The dispatch process starts with NEMMCO accepting electricity from the generator with the lowest price offer and then in sequence of the generator price offers. The acceptance of generated electricity is scheduled by NEMMCO to meet aggregate market demand. As electricity demand fluctuates in each half hourly period throughout the day, so does the amount of generation scheduled by generators for production. When demand is low, the lowest offer price generators are in production and when demand is high the more expensive generators are used (see figure 2.3 in section 2.2).

Source: NEMMCO (1999).

Figure 2.4 **Settlement of electricity prices in the National Electricity Market**



Source: NEMMCO (1999).

Market generators are paid for the electricity they sell to the pool and market customers pay for their electricity consumption. All market generators and customers settle their electricity sales and purchases from the spot market based on the spot price.

The two steps in calculating the spot price are:

1. The *dispatch price* is recorded as the marginal cost of supply to meet demand for each five minute interval in a half hour, after adjusting the offers and bids for electrical losses on the network.[12] This is typically the offer price of the last generator brought into production to meet demand.
2. The *spot price* is calculated as a time-weighted average of the six dispatch prices in a half hour (for each regional node – taking into account energy losses, inter-connecter capacity constraints and the ancillary services provided). Settlement is based on the spot price.

Buyers and sellers of electricity may seek to reduce risk through entering into long or short-term contracts that set an agreed price for electricity outside the pool to hedge the fluctuations in pool spot prices which vary every half hour in response to

12 In the centrally coordinated dispatch process, the dispatch offers and bids are used to schedule the generators into production to meet the forecast electricity demand.

electricity supply and demand.[13] The basic form of contract may be a bilateral hedge contract where two parties agree to exchange cash against the spot price. If the settlement price is above the contracted price, generators pay retailers the difference and *vice versa* when the price is below what has been contracted.

These hedge contracts do not affect the operation of the power system in balancing supply and demand in the pool and are not regulated under the Code.

The NSW Government has established a scheme that obviates the need for individual hedge contracts. An Electricity Tariff Equalisation Fund (ETEF) has been established for purchasers of energy from the NEM with an annual consumption under 160MWh who choose to accept prices from retailers. These prices are regulated by the Independent Pricing and Arbitration Tribunal of NSW (IPART). Customers may choose to receive a regulated price, comprised in part of a regulated energy cost (REC) derived from a weighted average of the existing tariffs currently used by retailers (NSW Treasury 2000).

When pool prices are higher than the REC, payments are made to electricity retailers out of the fund to enable them to earn a return on wholesale electricity purchases. When the pool price is below the REC, retailers are required to deposit the difference into the fund.

Government-owned generators are required to top up the fund, if pool prices are consistently greater than the REC and there is an ETEF shortfall.

Until July 2001, the NSW Government also required the six state-owned licensed distributors — Energy Australia, Integral Energy, North Power, Great Southern Energy, Advance Energy and Australian Inland Energy — to pay an Electricity Distributors Levy. The Levy aimed to protect the state-owned generators from losses as a result of substantial falls in electricity prices following the deregulation of the energy market in NSW.

The six distributors funded the levy through an increased network service charge to large contestable customers. The increased network service charge for 1997-98 was 0.55 cents per kilowatt hour and, for 1998-99, 0.52 cents per kilowatt hour.[14]

13 Generators and retailers can also sell or buy electricity futures contracts for the purpose of managing their respective risks. In Australia, prices and volumes of these contracts are published by the Sydney Future Exchange (SFE).

14 The increased network service charge is not levied on customers located outside of NSW or customers within NSW who source their power from outside the State.

Supply and demand bidding in the market does not determine all prices. In some countries, intervention occurs to cap the price when demand is high. In Australia, the maximum spot price is referred to as the Value of Lost Load (VoLL).

This cap is intended to prevent the price from exceeding the maximum price customers would be prepared to pay if they were buying direct from the market. It notionally represents the maximum value that customers would place on avoiding disruption. In Australia, VoLL is currently set at $5000 per MWh. The VoLL will be increased to $10 000 per MWh in 2001.

Customers do not generally respond to prices in real time, particularly when their electricity prices are set out in legislated tariff schedules. However, retailers may try to recover these costs through later adjustments in the tariff schedule in the form of higher prices.

When VoLL is reached and generators are unable or unprepared to meet supply, load shedding occurs to balance overall electricity supply and demand.[15] This imposes costs in the form of interruptions to business and personal inconvenience.

The price of electricity to wholesale customers is affected by the point at which they are connected to the network. It includes the wholesale price of electricity and a range of additional service charges for:

- transport (network services) and reticulation (distribution) together with the losses that occur in these processes;
- market participant fees (covering market operation) and ancillary service charges (covering the cost of technical services that ensure NEM system security); and
- other charges — taxes, levies and other government imposts.

These charges are independent of the spot price and any contract arrangements a participant enters into for electricity trading. Consequently, the average delivered price of electricity is much higher than average wholesale prices. For example, the average delivered price of electricity in Australia in 1998-99 was $89 per MWh, compared to the average spot price of $25 to $63 per MWh in NEM States (ESAA 2000b).

Network service charges — referred to as the Transmission Use of System (TUOS) charge in Australia — are applied for the use of the system in delivering electricity to contestable customers. Network service charges are applied on top of the

15 Load shedding occurs when demand exceeds supply of electricity and all reserves are used. As a last resort, customers are directed to reduce their consumption involuntarily to ensure that the power system always has a balance between supply and demand.

generated electricity price. They are paid by all market customers and passed on to end users purchasing electricity through a retailer.

Wholesale customers who use the distribution network are required to pay a TUOS charge and a charge for using the distribution network — referred to as Distribution Use of System (DUOS) charge in Australia. Wholesale customers are also required to pay their local Network Service Provider (NSP) a connection charge.

Market participant fees and ancillary service charges are two distinct costs.

Market participant fees are determined in accordance with principles contained in the National Electricity Code, subsequent NEMMCO determinations, and budget estimates agreed by the member jurisdictions. They are levied to recover the full cost of NEMMCO and the NECA operations.

For the 2000-01 year, the agreed revenue required to be raised through market participant fees is $63.35 million (NEMMCO 2001a). The market participant fee schedule for 2000-01, through which this amount is expected to be raised, is set out in table 2.2.

Ancillary service charges are imposed on market participants by NEMMCO to cover the cost of a range of technical services necessary to operate the electricity system in a safe, secure and reliable manner. NEMMCO mainly contracts out these service functions. The charges, levied on a user pays basis, cover such functions as automatic generation control, governor control, load shedding, rapid generator unit loading, reactive power, rapid generator unit unloading and system restart (NEMMCO 2001b).

NEMMCO estimate that in 2000-01 the cost of providing these ancillary services for the NEM was $272 million. Many of the services required are of an emergency nature and prior to the NEM they were performed by electricity utilities. They are now performed in a multi-jurisdictional context by agents acting for NEMMCO. Ancillary service charges are calculated for each NEM interconnected region. They can vary greatly through time, but selected NEMMCO data suggests that in most weeks they are equivalent to around $1 per MWh or 0.1 cents per kWh (NEMMCO 2001b).

Other charges may include environmental charges, State or national taxes and any other levies the government wishes to impose or allow the electricity supplier to recover. These are often applied at various stages in the supply chain with a proportion then passed on to the final customer.

Table 2.2 **Summary of Fee Schedule for 2000-2001**[a]

	Market customers	*Market scheduled generators and market non-scheduled participants*[b]	*Market non-scheduled and non-market scheduled generators*
NEMMCO Establishment fixed	0.02306	98.01840	49.00920
NEMMCO General fixed	0.04241	180.22923	90.11462
NECA Establishment fixed	0.00094	4.00938	2.00469
NECA General fixed	0.00404	17.17375	8.58688
Total Fixed[c]	0.07045	299.43076	149.71539
Minimum charge applies[d]	**$/MWh of customer load in 52 weeks to 25/03/00**[c]	**$/MW capacity at 31/03/00**	**$/MW capacity at 31/03/00**
NEMMCO Establishment variable	0.04463		
NEMMCO General variable	0.24619		
NECA Establishment variable	0.00183		
NECA General variable	0.02346		
Total Variable	0.31611 **$/MWh of customer load in current week**		
Full retail competition fixed[e]	0.00000 **$/MWh of customer load in 52 weeks**		
Full retail competition variable[e]	0.00000 **$/MWh of customer load in invoiced week**		
Participant compensation fund[f]	$0.00030 **/$ of energy sales**		
Registration applications	$1700 per application		

[a] Charges do not include GST. [b] Scheduled generators only contribute to the Participant Compensation Fund. [c] Fixed fees will be charged on a prorata weekly basis. [d] Minimum fixed charge of $9125 per participant applies. [e] New market customers will be charged the fixed fee on an estimate of future customer load. [f] Market customers with retail licences and second tier customers pay full retail competition charges.

Source: NEMMCO (2001a).

Prices to retail customers

Supply costs influence prices. The characteristics of electricity as a good and its economic characteristics as discussed in section 2.2 are intrinsic in determining pricing strategies.

Retailers typically set prices that vary with the time of day and the time of year for large business customers. Higher prices at peak times reflect higher wholesale prices that arise because of the higher cost of supplying electricity during these periods. That said, higher prices may also occur when demand is low if some generating capacity has been shut down.

Prices escalate rapidly in the short-run as demand approaches installed capacity and quick-start generators are engaged to cope with unexpected demand or technical failures (see figure 2.3). However, retail customers are usually quarantined from these price fluctuations, at least in the short-run.

The price paid by retail customers is also determined by the characteristics of customer demand and the responsiveness of supply to changes in price. Price discrimination, influenced by customer demands, is used by suppliers to selectively recover fixed costs from particular customer groups, subject to regulatory constraints.[16]

Demand and supply elasticities

Demand for electricity is relatively insensitive to price variations, that is, it is relatively inelastic, especially in the short-run because of its continuous consumption and non-storability characteristics.[17] Apart from oil and gas heating, it has few substitutes as a source of energy.

A number of studies were reviewed that estimated values for the price elasticity of demand for various types of user and over both the short and long-run. The elasticity values and study authors are listed in table 2.3.

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16 The situation for contestable customers is different due to the 'competitive' market structure they are in. Price discrimination may be practised but is difficult if not impossible to observe because prices paid by contestable customers tend to have commercial-in-confidence status.

17 An elasticity is a measure of the sensitivity of one variable to another. The price elasticity of demand measures the sensitivity of quantity demanded to price changes. It tells us what the percentage change in the quantity demanded for a good would be following a one per cent increase in the price of that good. When the price elasticity is less than one in magnitude, it is said that demand is price inelastic because the percentage decline in quantity demanded is less than the percentage increase in price.

Table 2.3 **Demand elasticity estimates**
Summary of research studies

	Residential customers		Commercial customers	
Author	*Short-run*	*Long-run*	*Short-run*	*Long-run*
Nan & Murray (1991)	-0.611	-1.1795	-0.7814	-0.8313
Beenstock et al (1999)		-0.532 (DRM) -0.579 (ML) -0.214 (EG)		-0.311 (DRM) -0.435 (ML) -0.002 (EG)
Tiwari (2000)	-0.7			
Filippini (1995)	-0.6 (peak) -0.79 (off-peak)	-0.71 (peak) -1.92 (off-peak)		
Herriges & King (1994)	-0.2 (summer) -0.4 (winter)			
Archibald et al (1982)	-0.4 (summer) -0.48 (winter)			
Barnes et al (1981)	-0.55			
Dubin (1985)	-0.16			
Dubin & McFadden (1984)	-0.25			
Goett & McFadden (1982)	-0.17			
Houston (1982)	-0.28			
McFadden et al (1977)	-0.37			
Chang & Hsing (1991)	-0.33			
Silk & Joutz (1997)	-0.62			

Source: Compiled by PC from published studies.

The supply of any good typically changes in response to both the price of the good being produced and the cost of the inputs used in its production. For most products, long-run supply is more price elastic than short-run supply because firms face capacity constraints in the short-run, and need time to expand their capacity by building new production facilities and hiring workers to staff them.

Studies with reliable estimates of supply elasticities for electricity were unable to be identified. However, it is useful to consider theoretically what the terms short and long-run supply elasticity mean in the context of the electricity industry.

In the electricity industry, it can take several years to plan, construct and commission new generating plants. In the short-run, supply can be increased by turning on existing but more costly to run plant. Generators switch on old but still commissioned baseload plant or peak load plant according to the expected short-run price.

Price discrimination

The forms of price discrimination applied in electricity pricing include peak load and multi-part tariff pricing (for a general discussion of price discrimination see box 2.6). These different forms of price discrimination can be embodied into the tariffs charged for both contestable and non-contestable customers.

Typically tariff structures for electricity are made up of access charges and usage charges. The access charge covers the cost of connecting a customer to the electricity network and maintaining the network. The access charge is independent of the amount of electricity used. Usage charges cover the cost of the electricity supplied and accrue on a kWh basis.

Different tariff structures combine both access charges and usage charges in different ways. There are five commonly used tariff structures — flat rate, block, heating, time-of-use and demand charge tariffs. These tariffs are often used in combination with each other.

Flat rate tariffs consist of an access charge and a usage charge that does not vary with the time-of-use or the quantity of electricity consumed and are an example of two-part price discrimination. Sometimes the usage charge may have a seasonal component, where, for example, the usage charge is higher in the summer than in the winter.

Block tariffs include a usage charge that varies with the amount of electricity used and are an example of multi-part pricing. This is the most common form of pricing for residential and commercial customers, and a clear example of second-degree price discrimination. As for the flat rate tariff, the usage charge may vary with the season.

Heating tariffs take two forms. In the first form, electricity used for heating is separately metered and a special heating charge is applied. In the second form, inter-temporal price discrimination is evident as the customer is required to have special heating equipment installed that is timer-operated or that can be controlled remotely by the utility. The equipment only functions during certain off-peak times and a separate off-peak heating tariff applies. Heating equipment of this kind usually embodies storage that the customer consumes at will, subject to the amount of heat storage. Thus, the pattern of heat consumption is decoupled from that of electricity consumption.

Box 2.6 **Price discrimination**

Price discrimination involves a business, with some degree of market power, selling different amounts of the same good at different prices, either to the same or different customers. In this way, customers are charged according to their individual ability and willingness to pay.

In order for price discrimination to be a viable strategy, the firm must have the ability to sort customers (or structure prices so that customers self-select into the appropriate categories) and prevent resale of the good in question.

Types of price discrimination are:

First degree price discrimination — involves charging a customer a different price for each unit equal to the maximum willingness to pay of the customer for that unit. This is also known as *perfect price discrimination*.

Second-degree price discrimination — occurs when prices differ depending on the number of units bought, but not across customers. Also known as *non-linear pricing*, the pricing schedule involves different prices for different amounts of the good purchased.

Third-degree price discrimination — occurs when customers with different demand characteristics are charged different prices, but each customer pays a constant amount for each unit of the good bought. Examples are student discounts, or charging different prices on different days of the week.

From these main forms of price discrimination, variations have been developed to suit particular industries. For the electricity supply industry, the following are prevalent:

Inter-temporal pricing — is closely related to third-degree price discrimination, where customers are separated into different groups with different demand functions and are charged different prices at different points in time.

Peak load pricing — takes into account that demand for some goods and services increases sharply during particular times of the day or year. Charging a higher price during the peak periods is more efficient because marginal cost is higher during peak periods due to the cost of supplying the additional capacity or capacity constraints.[a]

Two-part pricing — requires customers to pay a fee up front for the right to buy a product. Customers then pay an additional fee for each unit of the product they wish to consume.

Multi-part pricing — similar to the two-part pricing with a fixed access charge, but a uniform variable charge that changes after specified levels of consumption are reached.

[a] Peak load pricing is different from third-degree price discrimination, as the costs are different with peak load pricing. For example, costs are lower during the off-peak period. The rationale for third-degree price discrimination is in the differences in demand rather than differences in cost.

Sources: Pindyck & Rubinfeld (1992); Varian (1992).

Time-of-use tariffs consist of an access charge and a usage charge that varies with the time of day. Under these tariffs, the usage charge is set higher during those times of the day when demand is greatest. This is consistent with peak load price discrimination where the higher cost incurred for capacity to service demand in peak periods is reflected in the prices paid by the customers responsible for that demand.

Demand (capacity) charges are a charge on the maximum amount of kW used at any one time by a particular customer over a designated period. Relevant only to commercial and industrial customers in most cases, an annual charge per kW is applied according to the maximum amount of kW that a customer uses in a particular timeframe. Demand charges are used in conjunction with other tariffs, such as time-of-use and block tariffs and are a form of second-degree price discrimination.

Concessional tariffs may also apply. Certain groups in society are granted concessions in the prices they pay for delivered electricity. These groups include the elderly and disabled on pensions as well as the unemployed. These tariffs are examples of third-degree price discrimination, where customers are identified by their demand characteristics and charged accordingly.

Contracts that are struck between generators and retailers as discussed earlier, potentially provide an opportunity for first-degree price discrimination. The negotiation process that occurs for each contract, allows for prices to be based on the willingness to pay by individual customers. However, in some markets this is blunted by the possibility of arbitrage.

2.4 Factors affecting prices outside the control of the industry

The cost of supplying electricity is affected by natural, technological, market and regulatory factors that make up the total environment in which each utility operates. These factors fall into the following broad categories:

- Operating environment;
- Production economies;
- Energy losses; and
- Government imposts and interventions such as industry-specific taxes, environmental regulation and economic regulation.

The factors falling into these four categories are described below. Their nature and cost impacts vary from one utility to another. Consequently, they must be taken into account when comparing productivity or price performance on a like-with-like basis. For example, differences in government objectives and governance arrangements for publicly-owned utilities often affect cost of production and profitability.

There are also indirect interventions that affect incentives to be efficient. For example, interventions aimed at maximising competition also affect costs and profitability, and these are also discussed in the following section.

Operating environment

The operating environment — physical conditions, regulatory requirements affecting production and factor markets — influences capital and operating costs. Utilities must come to terms with the conditions under which they operate and optimise their plant and operations to minimise their overall costs.

Differences in the operating environment can affect the choice of technology, producing differences in costs and ultimately, prices.

Delivered cost of fuel — fuel costs have a significant impact on overall cost because fuel is a major input into the production of electricity. Low fuel cost, however, often signifies lower quality or energy content. Poor quality fuel usually requires additional capital investment to handle it and extract its energy content. Consequently, low cost, low quality (or low energy content) fuel does not lead directly to lower production costs.

Climatic conditions or features of the natural environment — weather and terrain influence production costs. This is in contrast with many products that can be produced in controlled environments. For example, environments with frequent extreme weather, such as hot weather or ice storms, require specific transmission and distribution lines that are durable in such conditions. These lines may not be the most efficient or least cost in the short-run, but require less maintenance than standard lines over their life.

Special lines are also installed to cope with specific terrain. For example, coastal areas require lines that are resistant to salt.

Customer demand characteristics — electricity supply production costs are affected by the demand characteristics of the customers. These characteristics principally affect capital inputs to generation.

Extent of contributed assets — many distributors receive assets (referred to as contributed or gifted assets) when land is developed for residential and industrial purposes. These assets reduce the capital cost to distributors of local reticulation of electricity. Consequently, differences in the extent of the practice can affect the capital cost of supplying some customers and therefore customer prices.

Production economies

The electricity supply industry is capital intensive. Further, there are often large indivisibilities because the relative cost of providing capacity initially is lower than the cost of incrementally increasing capacity as demand increases. This may lead to the capacity of the system being greater than required early in the life of the assets. In any case, redundant or spare capacity to cope with breakdowns is required because of the fact that electricity is an essential good, and because cost-effective technologies for its storage are not yet available.

There are a number of generally recognised types of scale economies in the production, delivery and reticulation of electricity. Four related commonly agreed upon economies in the delivery of electricity are:

Economies of output density — economies that arise when there is an increase in demand for electricity from a fixed number of customers and a fixed number of customers per kilometre of line.

Economies of customer density — economies associated with increases to both the number of customers and the quantity of output, but output per customer and the length of line remaining fixed.

Economies of size — a proportional increase in the volume of electricity supplied, the number of customers and the length of line, but with output per customer and customers per kilometre of line remaining fixed.

Economies of massed reserves — economies associated with the stochastic nature of demand and the reliability of system components. Electricity demand is stochastic because it fluctuates over time and cannot be predicted with certainty. Generating, transmission and distribution plant can fail or their capacity can be reduced because of random events such as the weather. The larger the system and the more it is interconnected, the smaller the percentage of reserve capacity required relative to demand.

Energy losses

Energy can be lost in the reticulation of electricity, particularly over the distribution network because of the length of line involved and the low voltage of the current carried over these lines (see box 2.7).

Box 2.7 **Why energy losses occur**

Transmission and distribution losses are intrinsically linked to the electricity supply network configuration, with their size depending upon voltage delivered and resistance encountered in delivery. The number of customers, kilometres of distribution line, locational and physical factors all contribute to resistance in delivering of electricity to final customers.

Electricity is transported from generators to final customers by both transmission (high voltage) and distribution (low voltage) networks (see appendix B). The elements that make up these networks are not perfect conductors of electricity and resistance is encountered in the physical process of delivering power through these networks.

A small amount of electricity is 'lost' when being transported from one point to another because of resistance within conductors. Consequently, a generator must produce enough electricity to satisfy customer load requirements plus an amount of electricity that is lost during transmission and distribution. This network loss contributes to the cost of supplying power to customers. The spatial pattern of such losses must be considered when determining the most efficient location of generators and dispatch to satisfy load requirements.

Losses in a particular element of the network are given by:

Transmission loss = I^2*R, where:
I = current flowing through the network element; and
R = resistance of the network element.

Losses therefore vary depending upon the current that is being pushed along the network and the resistance that is encountered.

A consequence of squaring the current is that new customers at the 'end' of an electrical network (the lowest level of voltage in the distribution network) will cause greater additional losses in the network than the losses due to prior existing usage of equal magnitude. These customers at the 'end' of an electrical network thus contribute to the greatest losses in transmission and distribution.

There are a number of factors that influence either the current delivered and/or resistance and hence losses in a particular network. These factors include climate, the total demand for electricity and the length of transmission and distribution line. Also of influence is customer density and the mix of final demand for electricity, and technical network design at the transmission, sub-transmission and distribution levels (underground cables and level of series and shunt losses incurred).

Losses are at lower levels in the predominantly urban networks relative to the predominantly rural networks because urban networks have lower levels of resistance in delivering electricity over shorter distances.

Source: NEMMCO (1999).

Losses arise due to the laws of physics and are thus largely unavoidable. They may also arise from illegal connections, meter tampering (electricity theft), metering errors and shortfalls in billing and revenue collection.

Energy loss levels are affected by a number of factors, including the cost drivers underlying production economies. For example, low customer densities can increase losses because longer lengths of distribution line must be used.

To some extent, system design can mitigate loss levels. However:

> While there are numerous opportunities for improving efficiencies in the delivery of electricity, the magnitude of the efficiency gains that can be realised is limited. … Potential reductions in these losses attainable through such means as 'reconductoring' and the installation of high-efficiency transformers are smaller still. Nonetheless, a reduction of 1 percentage point in system losses can represent a significant efficiency improvement (EIA(US) 1996).

Government interventions

Governments have intervened in electricity markets because of perceived market failures such as monopoly and externalities. Some of these interventions impact directly on the industry, affecting their production costs and the price of electricity. Although governments intervene because they believe it is in the public interest to do so, the interventions differ and affect prices to varying degrees.

Taxes

The electricity industry is subject to taxes that vary from country to country and within countries. Taxes affect customer prices to the extent that they are passed on by suppliers. Consequently, they must be taken into account when comparing price outcomes for customers and examining price performance.

When comparing price outcomes for customers, industry-specific taxes that vary from jurisdiction to jurisdiction or general taxes that fall disproportionally on the industry (for example certain input taxes) affect price relativities. Taxes that apply uniformly to most goods and services are irrelevant when comparing prices of electricity relative to other goods and services across countries.

When comparing price performance — the extent to which prices reflect efficient production costs and pricing — differences in the overall level of taxation must be taken into account. Taxes, if not taken into account along with other cost factors, would give a false picture of the price differences attributable to differences in price performance.

Tax concessions that are specific to an industry only have a minor effect on the general level of prices in a country. Consequently, differences are only partially taken into account when comparing prices among countries after adjusting for the general level of prices.

Taxes on inputs — inputs are taxed for general taxation purposes — that is, for reasons other than meeting environmental objectives. The inelastic demand for electricity mitigates the distortion to overall resource use of these taxes.

Government regulations affecting the cost of fuel — governments sometimes regulate the coal industry, coal storage and its transport. This type of regulation usually adds to the cost without providing a compensating benefit to generators.

Taxes on consumption or outputs — taxes are also imposed on outputs, typically for general taxation purposes.

Industry levies in support of stranded assets — in some countries, levies are charged to cover the cost of stranded assets. These levies are usually thought to be justified when governments change standards and other regulation that renders an asset unusable and its cost cannot be recovered, that is, it becomes a sunk cost.

Subsidies in support of other industries — some governments use the electricity industry to subsidise other industries such as coal mining.

Levies for social programs — levies are also placed on electricity to raise revenue for social programs such as schools. These are in effect hypothecated taxes.

Tax concessions — governments provide tax concessions on inputs and capital expenditure to specifically assist the electricity industry. This reduces costs and possibly prices.

Environmental regulation

Electricity supply gives rise to a number of costs that are not borne by the industry. Some of these so-called externalities adversely affect the environment. Governments are increasingly concerned to ensure that such costs are met by the industry, so that suppliers are aware of the full cost of their activities and are provided with an incentive to ensure that their operation is efficient overall.

Regulated emission limits and other regulations that cause environmental costs to be factored into fuel and other input costs — governments place limits on the level of emissions to mitigate adverse consequences on the environment. These limits increase both the capital and operating costs of producing electricity to facilitate an efficient economy-wide use of resources by attempting to ensure that users bear their full costs.

Government requirements and restrictions on business operating practices — governments also impose requirements on such things as employment conditions and the placement of power lines that affect costs.

Economic regulation

In the past, government intervention took the form of direct involvement. In recent years, governments in many countries have or are in the process of privatising the industry. However, many public suppliers remain in Australia and other countries.

Dividend and rate of return policies for publicly-owned utilities — government involvement can affect costs differentially because of different governance arrangements. For example, governments in Australia have emphasised the importance of competitive neutrality and exposing public trading enterprises to factor market disciplines. They require publicly-owned electricity utilities to achieve a normal rate of return on their assets and make dividend payments.

Community Service Obligations — governments sometimes use their utilities to achieve social objectives. When they do so, costs can be borne by governments or by customers or groups of customers through cross-subsidisation.

Retail price controls — prices are often regulated by governments to mitigate market power. They do so to prevent inefficient pricing and excessive profits. Differences in the degree of stringency affects efficiency and profitability, and hence prices.

In many countries, price caps are formulated to provide incentives to improve efficiency. This incentive regulation provides for a sharing of productivity gains between the produces and customers.

Price caps that distort investment decisions will affect efficiency over time (dynamic efficiency). This factor is outside the control of the industry. However, it is difficult to take account of when comparing price outcomes.

Price caps can also affect efficient pricing as well as investment decisions and competition. For example, price caps that favour residential customers in one country may result in higher prices for business customers. Hence, residential price relativities may compare favourably and business price relativities less favourably.

When comparing price performance, it is necessary to examine price differences across a range of customers. However, the affect on dynamic efficiency and the influence of differences in the competitive environment due to distortionary prices across customers are difficult to assess.

2.5 Residual factors

There are factors that account for price differences, other than those outside the control of suppliers described in section 2.4. Electricity prices are affected by the productivity of the industry and the economy generally, by the prices of inputs and by the financial performance of the utilities.

The greater the productivity of the industry, the lower electricity prices will be (for a given financial performance). Increased productivity in the industry (generated by technological innovation or more efficient use of resources) may be partially absorbed by higher input prices. However, the remaining benefit is available to lower electricity prices or to increase returns to shareholders.

Conversely, high electricity prices in a country (compared with another country) could be attributable to:

- low productivity in the industry;
- high profits;
- high input prices for the industry (compared with input prices in other sectors of the economy); or
- high economy-wide productivity (which results in higher wages and other factor prices in that country).[18]

This decomposition is described algebraically in box 2.8.

The first two circumstances are more likely to occur when the extent of competition in a country's electricity supply industry is relatively low. As already indicated, low productivity can be in whole or part a result of factors outside the control of industry participants.

High input prices may also be encouraged when there is limited competition in the industry and among supplying industries. For example, the industry has been viewed by some as being vulnerable to high labour inputs in the past, because of the essential service nature of electricity supply.

The last circumstance (high economy-wide productivity) is associated with generally more well endowed and developed economies.

[18] Or any combination of the above. In fact, a country could perform well in one or more areas but the benefits could be more than offset by performance in other areas.

Box 2.8 **Decomposition of productivity changes**

Total factor productivity (TFP_E) for a electricity supplier may be estimated as the quantity of its output (Q_E) per unit of quantity of input (I_E), with quantities measured by appropriate indexes. Inputs include labour, materials and other services.

As revenue is price times output, the quantity index for outputs may be estimated by the revenue (R_E) earned from the output divided by a price index for output (P_{OE}). Similarly, the quantity index for input is equal to expenses (E_E) incurred in producing the outputs divided by a price index for inputs (P_{IE}).

Therefore, for the electricity industry in any country:

$$TFP_E = Q_E/I_E = (R_E / P_{OE})/(E_E / P_{IE}) = (R_E / E_E)/(P_{OE} / P_{IE}) = (R_E / E_E)*(P_{IE} / P_{OE}).$$

In terms of percentage differences (%Δ) between utilities (or percentage changes over time for a single utility):

$$\%\Delta TFP_E \cong \%\Delta(R_E / E_E) - \%\Delta(P_{OE} / P_{IE})$$

$$\%\Delta(P_{OE}/P_{IE}) \cong \%\Delta(R_E / E_E) - \%\Delta TFP_E$$

The above equation implies that differences in output to input price ratios are equal to differences in financial performance (measured by the ratio of revenue to expenses) less differences in productivity.

Assume that P_{GDP} is the price of an economy-wide basket of goods and services in Australia. Now let P_{IGDP} be the price of a broad economy-wide basket of business inputs in Australia. By substitution, TFP may then be decomposed as follows:

$$TFP_E = (R_E / E_E) * (P_{IGDP} / P_{GDP}) * (P_{IE} / P_{IGDP}) / (P_{OE} / P_{GDP})$$

Further substitution is possible by noting that the total factor productivity for the whole economy (TFP_{GDP}) is given by:

$$TFP_{GDP} = P_{IGDP} / P_{GDP}$$

where the provision of capital and entrepreneurial skill is included among the business inputs.

Therefore:

$$TFP_E = (R_E/E_E) * TFP_{GDP} * (P_{IE} / P_{IGDP}) / (P_{OE} / P_{GDP})$$

Or in percentage terms:

$$\%\Delta TFP_E \cong \%\Delta(R_E / E_E) + \%\Delta TFP_{GDP} + \%\Delta(P_{IE} / P_{IGDP}) - \%\Delta(P_{OE} / P_{GDP})$$

Yielding:

$$\%\Delta(P_{OE} / P_{GDP}) \cong - \%\Delta TFP_E + \%\Delta(R_E / E_E) + \%\Delta(P_{IE} / P_{IGDP}) + \%\Delta TFP_{GDP}$$

High electricity prices may also be a result of internal factors which are indirectly influenced by external factors:

- Low (absolute) productivity — the first circumstance — is to some extent within the control of suppliers as is high profitability. However, low apparent (relative) productivity can also be due to factors outside the control of suppliers;
- High profitability — the second circumstance — is entirely attributable to internal policies. However, the ability to charge high prices and earn excess profits is constrained by competition in both factor and electricity supply (product) markets and by the effectiveness of any price regulation;
- Relatively high input costs — the third circumstance — are partially under the control of management. However, these costs can be influenced by the extent of competition or the effectiveness of price regulation within the industry and across the economy as a whole.
- High economy-wide productivity — the fourth circumstance — is an external factor. This factor can be taken into account by comparing prices after adjusting them for the general price level in each country. That said, the productivity of the electricity industry plays an important role in economy-wide productivity.

As indicated above, some of the internal factors are affected by the incentives provided by competition and by the effectiveness of competition and price regulation.

Recently, there has been a shift from supervision of monopolies to encouraging competition in those parts of the industry where competition is possible — notably generation. This policy approach was undertaken because it was thought to produce greater benefit than any loss of economies of scope or dynamic efficiency inherent in vertical integration.

The trend toward encouraging competition requires vertical disaggregation. It implies that governments believe that the benefits outweighed the additional transaction costs of creating and operating a market. Further, prices in these markets were believed to provide adequate signals and incentives for investment.

Differences in the effectiveness and efficiency of competition regulation therefore have an indirect impact on prices. Differences in the stringency of price regulation have a more direct impact on prices. However, if regulation discourages investment, it can have a deleterious impact on efficiency in the long-run.

2.6 In summary

Electricity is an important input to industry and electricity supply is regarded as an essential service. Given the value of its outputs, electricity is a significant industry in its own right.

The industry's importance is likely to continue into the future, with increasing reliance on computers as the 'new economy' develops. This will generate demand for high service quality, with reliable supply at stable voltages.

The industry is undergoing significant structural change. In recent years, governments in many countries have introduced strategies to increase the level of competition and overall efficiency. There have also been developments in regulation aimed at providing incentives to mitigate abuses of market power. Initiatives directed at environmental concerns can be expected to be significant drivers of change as well.

The characteristics of production of electricity and its nature influence the way the industry is organised and prices are set. Of particular significance are monopolistic characteristics, particularly in the transmission and distribution sectors.

Continuous consumption, ineffective short-run demand signals, difficulties in storing electrical energy and the high cost of meeting demand peaks give rise to price volatility in markets where electricity prices are determined through an auction process. This has created a need for financial instruments that provide a hedge against price uncertainty.

The industry has a long tradition of price discrimination, with tariff structures comprising of fixed and variable charges that change with the quantity of electricity consumed. In the US in particular, the average price paid by a customer decreases as the quantity consumed increases. In the Australian market, the scope for price discrimination is decreasing with the vertical disaggregation of the industry and a large proportion of prices set at long-run marginal cost (average avoidable cost).

In the light of differences in the scope to price discriminate and the pricing strategies employed by utilities, tariff structures vary between countries. This can be expected to lead to the price relativities reported in chapters 3, 4 and 5 changing with customer type and the quantity of electricity consumed among the utilities studied.

There are a large number of factors that influence productivity and which are outside the control of suppliers in the short-run — the period relevant to pricing decisions when major capital inputs cannot be changed. The number and materiality of these factors is such that there are likely to be large cost of supply differences among the utilities studied. These cost differences affect prices and are likely to account for some of any observed price differences between utilities studied.

One such factor, differences in the quality of service is examined in chapter 6. The influence of a large number of other factors is examined in chapter 7.

Finally, any residual difference in prices after cost differences outside the control of suppliers are taken into account, are the consequence of measurement error, productive inefficiency or monopoly profits. Some of these causes of poor price performance — prices that do not reflect the cost of efficient supply and pricing — can be addressed by maximising competition and, if necessary, efficient regulation.

3 Unadjusted residential prices

The prices paid by residential customers of electricity services in Australia are compared with the prices paid by residential customers in other countries in this chapter.

A broad picture of relative prices in different countries is presented. The comparisons are based on many assumptions related to the specification and pricing of the services provided to customers. The effect of changing the most important assumptions is investigated in order to test the robustness of the approach.

Comparisons of the prices paid by small and medium-sized businesses and contestable customers are presented in chapters 4 and 5.

Prices are affected by cost factors outside the control of the industry. The prices presented are not adjusted for these cost factors. The significance that these factors have for average price comparisons is discussed in chapter 7.

3.1 Methodology

The average price in cents per kiloWatt hour (kWh) paid by residential customers for one year's supply of electricity is calculated for a number of distributor-retailers using tariff rates available in October 2000. A number of different consumption patterns are used as a basis for comparison.

Average prices are converted into indexes that correct for differences in the general price level in each country, to provide a practical means of comparing overall prices.

Electricity utilities

The Australian distributor-retailers were chosen to give a sample that was representative of prices paid by a relatively large proportion of Australian residents and covering most States and Territories. Some of the smaller distributors in the largest States have been omitted to make the comparisons manageable.

The choice of overseas utility was based on a number of criteria used to ensure that the operating circumstances of the overseas utilities resembled as closely as possible those faced by Australian utilities.

A list of the utilities studied and the criteria used to select them are presented in chapter 1.

Residential consumption bundles

Patterns of consumption across countries are related to the level and the structure of prices. Electricity tariff structures are often designed to suit local climatic and demand conditions. For example, in colder climates, winter tariffs are often set higher than summer rates to reflect heavier usage during the winter season.

Consumption bundles that are used to compare the performance of different utilities, should be neutral in their impact on the measurement of prices. Neutral bundles reflect the consumption patterns of customers in different countries, and therefore do not advantage utilities in one country over utilities in other countries.

In the absence of a single neutral bundle, a range of bundles was used to reflect consumption patterns in all countries.

The residential bundles chosen as a basis of comparison are based upon Australian consumption patterns, and are a subset of those used by the Electricity Supply Association of Australia (ESAA) in its publication, *Electricity Prices in Australia, 2000/2001* (see table 3.1). The bundles are sufficiently wide-ranging in scope to be representative of residential consumption patterns in the countries included in this study (see chapter 1).

The bundles ranged from 1200kWh to 20 000kWh of annual consumption. Annual average residential consumption in Australia was 6647kWh in 1999, although this ranged between 5325kWh in WA and 9052kWh in the ACT (ESAA 2000b). As an example of residential consumption levels among the overseas utilities studied, annual average residential consumption for Empire District was 12 419kWh, while, for Israel Electric, it was 5623kWh.

The range of consumption volumes selected provides information on price outcomes for residential customers who consume different amounts of electricity. The quantity of annual consumption subject to either off-peak heating tariffs or time-of-use tariffs varies between the bundles to determine the effect on electricity prices.

Table 3.1 **Residential consumption bundles**

Bundle name	*Tariff type*	*Annual consumption*	*Proportion of off-peak under a heating or time-of-use tariff*	
		kWh	kWh	per cent
RB1	Standard	1200	0	0
RB2	Standard	7500	0	0
RB3	Standard with a proportion subject to water and/or space heating	7500	3000	40
RB4	Standard with a proportion subject to water and/or space heating	20 000	8000	40
RB5	Time-of-use	7500	2250	30
RB6	Time-of-use	20 000	8000	40

Source: ESAA (2000a).

The effect of changing the assumptions underlying the choice of consumption bundle is discussed in section 3.3.

Calculation of average prices

For each Australian utility, the average price in cents per kWh of each bundle was taken from the ESAA's publication, *Electricity Prices in Australia, 2000/2001*. This publication features three main residential tariff types: standard, heating and time-of-use. In all cases, the tariff type yielding the cheapest price for each bundle is reported given the consumption pattern defined by the bundle. The names of the tariffs used to calculate average prices are listed in appendix C.

One average price for each consumption bundle is reported for all the Victorian distribution businesses (DBs). Small differences in final prices exist between the DBs because of marginal variations in allowable Goods and Services Tax (GST) pass-through.[1] However, for the purposes of comparison, ESAA chose Powercor's price to be representative of all five DBs.

Average prices in Victoria were calculated using the tariff schedule applicable at October 2000. A new residential tariff schedule commenced on 1 January 2001. The impact upon prices of the revised schedule is discussed in section 3.3. The other Australian utilities have not had their prices reviewed.

[1] Allowable GST pass-through for each DB is as follows: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent (ESAA 2000a).

Some utilities are required by government to provide concessions to particular groups within the community, for example, pensioners. Where concession rates exist, other tariff rates may be higher in order to cover the cost of providing these concessions.

For each overseas utility, the average price per kWh of each residential bundle was calculated using the tariff rate that minimised the total cost of the bundle to the customer. Where customers were eligible to receive their electricity under more than one tariff, the bundle was costed using each of the eligible tariff rates and the tariff that gave the minimum cost was selected.

An average price per kWh was calculated by dividing each costing by the total annual consumption of electricity. The calculations used to generate the average price for each overseas utility were verified by the relevant utility.

Some utilities in the United States operate across state borders and usually have a separate tariff schedule for each region of operation. For example, Mid American Energy Company operates in Iowa, Illinios and South Dakota and has a separate tariff schedule for each state.

In this case, the tariff schedule that relates to the utility's largest customer base was used. For example, Mid American Energy's tariff schedule for Iowa, which represents around 90 per cent of Mid American Energy's customer base, was used.

Taxes

Surcharges specific to individual utilities and indirect taxes were included in the calculation of total cost as these charges are included in the price that customers pay.

Government imposts, such as taxation, are discussed in chapter 7.

Conversion to a common unit of account

Comparisons of the average price paid per kWh for each consumption bundle involve:

- valuation of the bundle in the local currency; and
- conversion from the local currency to a common unit of account.

Purchasing power parities (PPPs) were used in this study for the conversion of local currency electricity prices into a common unit of account — in this case, Australian dollars.

PPPs are rates of conversion designed to equalise the internal purchasing power of currencies by eliminating differences in general price levels between countries. A given sum of money, converted into other currencies at PPP rates, should buy a similar broad and representative basket of final goods and services in each country.

This would not necessarily be the case if market exchange rates were used. Market exchange rates are determined by trade in a smaller (traded) basket of goods, by capital inflows and outflows, by government policies on quotas, tariffs and taxes, and by expectations. Consequently, comparisons based on market exchange rates are often volatile, particularly when capital flows are volatile. The rates may shift abruptly with changed expectations, government trade and tax policies, trade patterns and monetary conditions — thus they can quickly become dated.

A second disadvantage is that exchange rates do not reflect the relative prices of all goods and services produced in a country. Instead, the relative prices of tradeable goods, as well as other factors such as net capital flows, affect exchange rates. The use of market exchange rates to convert the cost of a non-tradeable service such as electricity may therefore give misleading results.

The particular PPP rates used for this study are given in table 3.2 and are the same as those used by the OECD for other price comparisons. They were constructed by the OECD using a broad basket of goods and services weighted to be representative of the average expenditure patterns of households throughout OECD member countries.

Table 3.2 **PPP exchange rates used for the price comparisons, 2000**

Country	*Unit of local currency*	*$A equivalent of unit of local currency*
Australia	Australian dollar	1.00
Canada	Canadian dollar	0.90
Germany	Deutschmark	1.54
Israel	New Israeli Shekel	2.96
United States	US dollar	0.77

Source: OECD (1999).

When electricity prices are converted using PPPs, the resultant index is the ratio of electricity prices to the price of other goods and services in that country (see box 3.1). This index indicates the number of units of Australian dollars needed to buy a given quantity of electricity in each country.

The effect of using market exchange rates instead of PPPs as a basis for currency conversion is discussed in section 3.3.

Box 3.1 **PPP and the interpretation of PPP adjusted electricity prices**

Purchasing Power Parity (PPP_{GDP}) is an exchange rate that is adjusted to eliminate differences in the general level of prices. It is derived by determining the equivalent cost of purchasing a fixed basket of goods and services using a reference currency.

The PPP for country *i*, expressed in terms of Australian dollars, is calculated as:

$$PPP_{GDP\ i} = P_{GDP\ i} / P_{GDP\ (AUS)}$$

where P_i is the price of an economy-wide basket of goods and services in country *i* and P_{AUS} is the price of an economy-wide basket of goods and services in Australia.

Comparing electricity prices

The price of a basket of electricity in a country ($P_{OE\ i}$) can be expressed in terms of Australian dollars by using PPP rates as follows:

$$P_{OE\ i\ (AUS)} = P_{OE\ i} / PPP_{GDP\ i}$$

where $P_{OE\ i\ (AUS)}$ is the price of electricity in country *i* expressed in Australian dollars and $P_{OE\ i}$ is the price of electricity in country *i* expressed in local currency.

Substituting the expression for PPP in the above identity:

$$P_{OE\ i\ (AUS)} = (P_{OE\ i} / PPP_{GDP\ i}) * P_{GDP\ (AUS)} = (P_{OE\ i} / PPP_{GDP\ i})$$

where $P_{GDP\ (AUS)}$ is constant at a point in time (while $P_{OE\ i} / PPP_{GDP\ I}$ varies by country).

PPP adjusted prices are therefore an index of the price of electricity relative to other goods and services in that country — that is, the extent to which the price of electricity is higher or lower than other goods and services in any country. Consequently, it is a measure of whether customers in a country are relatively better or worse off on the basis of electricity charges.

Comparing differences in price

$$P_{OE\ i\ (AUS)} = (P_{OE\ i} / PPP_{GDP\ i}) * P_{GDP\ (AUS)}$$

With $P_{GDP\ (AUS)}$ a constant (k)

$$P_{OE\ i\ (AUS)} = (P_{OE\ i} / PPP_{GDP\ i}) * k$$

Consequently, for comparisons between countries, the per cent difference (Δ) in the ratios of the price of electricity to the general price level in each country is approximately the same as the per cent difference in electricity prices converted to Australian dollars using PPPs. That is:

$$\Delta(P_{OE\ i\ (AUS)}) = \Delta(P_{OE\ i} / PPP_{GDP\ i}) = \Delta(P_{OE\ i} / P_{GDP\ i})$$

Note that for comparisons of electricity price changes (relative to the general price level) within a country over time, $P_{GDP\ (AUS)}$ is not constant. Taking inflation into account, the formula becomes:

$$\Delta(P_{OE\ i} / P_{GDP\ i}) \cong \Delta(P_{OE\ i} / PPP_{GDP\ i}) - \Delta(P_{GDP\ (AUS)})$$

Source: PC.

3.2 Prices

The price that residential customers pay for an electricity service generally consists of an access charge and a usage charge. These charges are combined in different ways to form different tariff structures. There are four commonly used residential tariff structures: flat rate tariffs, block tariffs, heating tariffs and time-of-use tariffs.[2] The types of tariffs used by each of the utilities studied were listed in section 2.3.

The price regulations governing residential tariff rates in Australia and in the overseas countries included were discussed in chapter 2.

Assumptions used in the price comparisons

Where tariffs contained usage charges that varied seasonally, annual consumption was assumed to be spread over the year according to the seasonal patterns used by the UK-based Electricity Association (EA) (1999).[3] In applying this seasonal spread, a 50 per cent load factor was assumed as this approximated the average load factor of the Australian utilities (table 3.3).

The effect of changing the load factor assumption is discussed in section 3.3.

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[2] A fifth type of tariff structure — demand (capacity) charges — are more frequently used in small to medium and large business tariffs.

[3] ESAA (2000a) makes certain assumptions in calculating average prices per kWh for each of the Australian utilities. However, because Australian tariffs do not tend to vary seasonally, ESAA did not include any assumptions about how consumption varied with the seasons. Consequently, the PC has used the EA's assumptions for this purpose when calculating average prices per kWh for the overseas utilities.

Table 3.3 **Assumptions on seasonality of consumption, northern hemisphere**

Month	*Proportion of annual consumption used each month*[a]
	per cent
January	9.08
February	8.70
March	9.15
April	8.25
May	8.33
June	8.15
July	7.43
August	7.30
September	8.30
October	8.55
November	8.85
December	7.93

a Assumes a 50 per cent load factor.

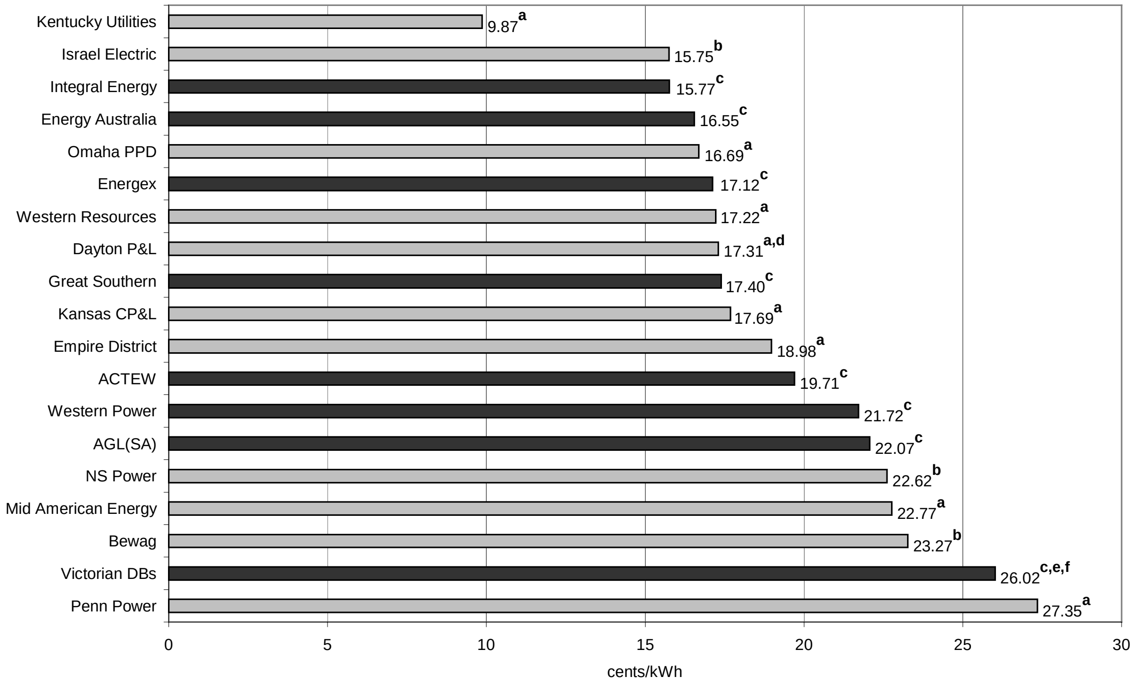
Source: EA (1999).

Consumption bundles RB1 and RB2

The results of the price comparisons for RB1 and RB2 are presented in figures 3.1 and 3.2 (Australian utilities are represented by the dark coloured bars). For all utilities, flat rate tariffs or block tariffs produced the lowest average price per kWh.

Where there was a seasonal component to the tariff, the recognised length of the seasons often varied between utilities. For example, the Omaha Public Power District’s (Omaha PPD’s) winter period extended from October to May, while Penn Power’s winter period covered November to May. In the Northern Hemisphere, winter electricity rates were often lower than summer rates. Hence, a longer winter period would have the effect of lowering the overall cost of the bundle.

Figure 3.1 Unadjusted average price index: RB1, Australian dollars, October 2000



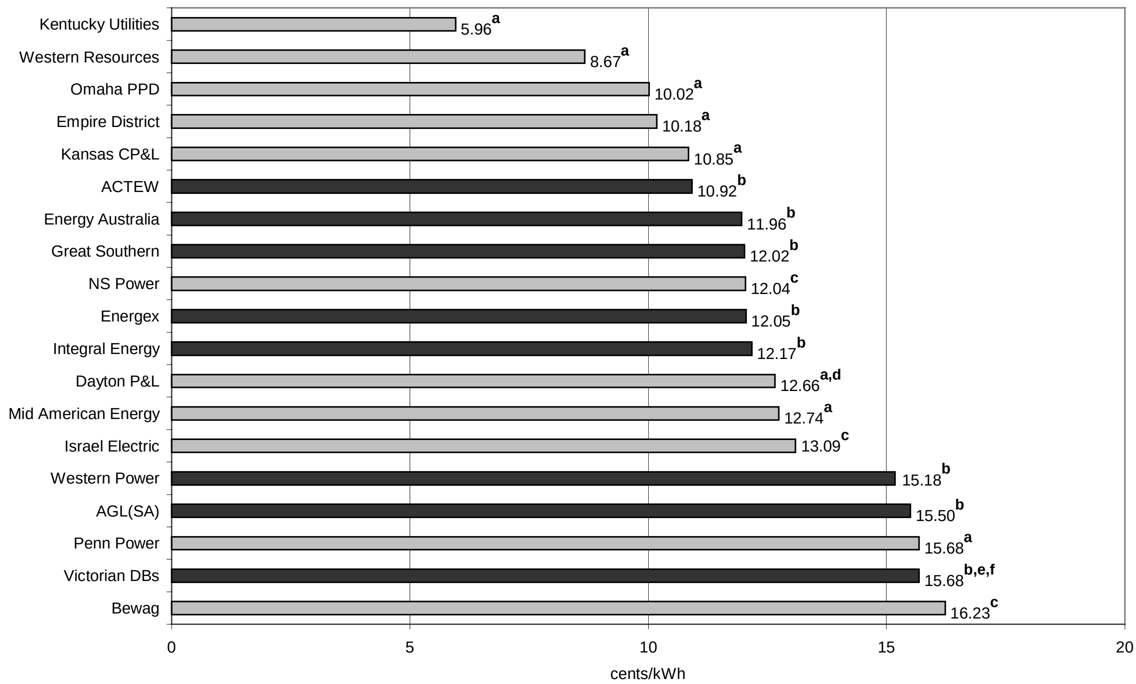
Note RB1 has a total annual consumption of 1200kWh, with no off-peak heating or time-of-use consumption. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. [a] Block tariffs produced the lowest average price per kWh. [b] Flat rate tariffs produced the lowest average price per kWh. [c] ESAA used the standard domestic tariff published by each utility to calculate Australian utility prices. Standard domestic tariffs are structured as either flat rate tariffs or block tariffs. [d] Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge. [e] Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. [f] In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs.

Data sources: ESAA (2000a); PC estimates.

Average prices were lower for RB2 than for RB1. For example, the average price per kWh for Energy Australia was nearly 40 per cent lower for RB2 (11.96 cents per kWh) than RB1 (16.55 cents per kWh). This is most likely due to access charges being spread over a larger usage as total annual consumption increased from 1200kWh for RB1 to 7500kWh for RB2.

There was also some variation in the price relativities between RB1 and RB2. For example, the relative rankings of ACTEW and Great Southern Energy (GSE) improved relative to the two Sydney-based utilities as the customer's total annual consumption increased.

Figure 3.2 **Unadjusted average price index: RB2, Australian dollars, October 2000**



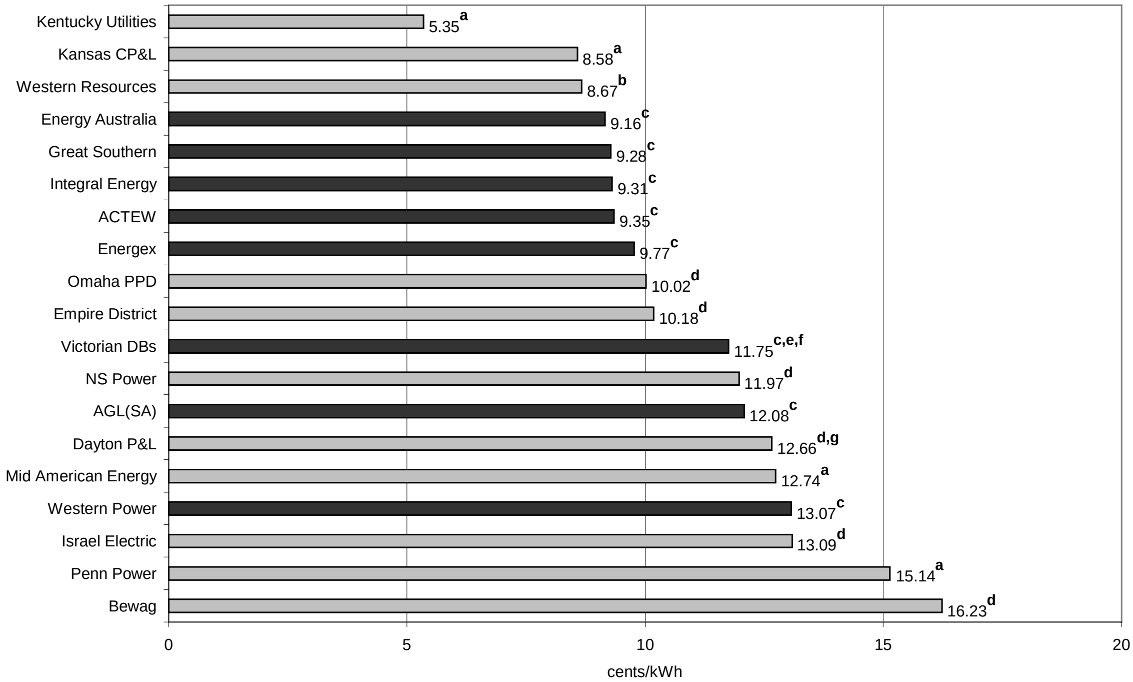
Note RB2 has a total annual consumption of 7500kWh, with no off-peak heating or time-of-use consumption. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Block tariffs produced the lowest average price per kWh. **b** ESAA used the standard domestic tariff published by each utility to calculate Australian utility prices. Standard domestic tariffs are structured as either flat rate tariffs or block tariffs. **c** Flat rate tariffs produced the lowest average price per kWh. **d** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge. **e** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs.

Data sources: ESAA (2000a); PC estimates.

Consumption bundles RB3 and RB4

The results of the price comparisons for RB3 and RB4 are presented in figures 3.3 and 3.4. Except in a few cases, heating tariffs produced the lowest average prices per kWh for each utility. In Australia, these tariffs were used in conjunction with the applicable flat rate tariff.

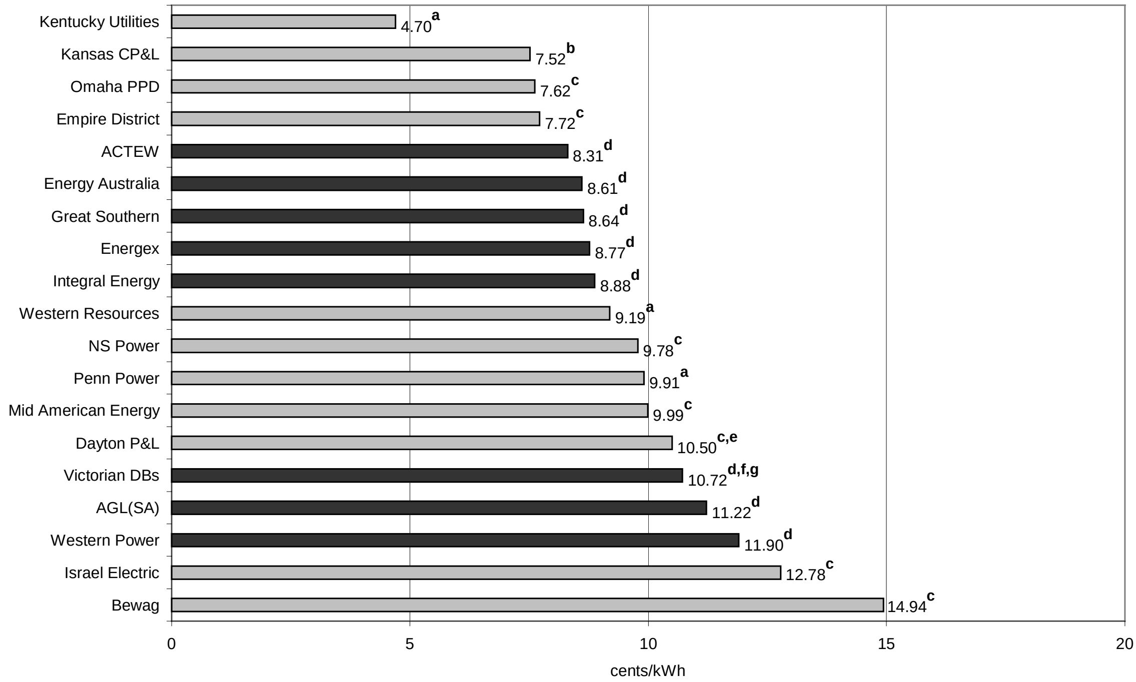
Figure 3.3 Unadjusted average price index: RB3, Australian dollars, October 2000



Note RB3 has a total annual consumption of 7500kWh, of which 3000kWh is used in either hot water or space heating. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Heating tariffs produced the lowest average prices per kWh for each utility. **b** Heating tariff available but block tariff produced a lower average price per kWh. **c** ESAA used domestic off-peak heating tariffs in conjunction with the standard domestic tariff to calculate average prices for each of the Australian utilities. **d** Average prices per kWh were lowest using either a time-of-use tariff, block tariff or a flat rate tariff. Heating tariffs were unavailable. **e** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs. **g** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge.

Data sources: ESAA (2000a); PC estimates.

Figure 3.4 **Unadjusted average price index: RB4, Australian dollars, October 2000**



Note RB4 has a total annual consumption of 20 000kWh, of which 8000kWh is used in either hot water or space heating. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Heating tariffs produced the lowest average prices per kWh. **b** Heating tariff was available but block tariff produced a lower average price per kWh. **c** Average prices per kWh were lowest using either a time-of-use tariff, block tariff or a flat rate tariff. Heating tariffs were unavailable. **d** ESAA used domestic off-peak heating tariffs in conjunction with the standard domestic tariff to calculate average prices for each of the Australian utilities. **e** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge. **f** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **g** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs.

Data sources: ESAA (2000a); PC estimates.

NS Power, Empire District, Dayton Power and Light (Dayton P&L), Omaha PPD, Bewag and Israel Electric did not have heating tariffs. Their lowest average prices were generated using either a time-of-use tariff, block tariff or a flat rate tariff.

Average prices for the Australian utilities were generally lower for RB3 than for RB2 even though both bundles had the same level of total annual consumption. The lower prices most likely reflects the effect of charging for a proportion of annual consumption at lower heating rates.

Average prices for Dayton P&L, Empire District, Omaha PPD, Bewag and Israel Electric remained unchanged between RB2 and RB3. This was a result of the fact that these utilities did not have heating tariffs available and, as for RB2, either a flat rate or block tariff was used to calculate prices.

Overall, the average prices per kWh for RB4 were generally lower than those for RB3, even though under both bundles 40 per cent of total annual consumption was subject to heating tariffs. The lower average price for RB4 is most likely a result of the access charge being spread over a much larger consumption base in RB4 compared with RB3.

There was some change in the relative position of some utilities. This was most likely due to differences in the relative importance various utilities place on access charges as opposed to usage charges in their tariff structure. Where a utility placed a heavy reliance on access charges, that utility's relative position would improve as consumption increased.

Consumption bundles RB5 and RB6

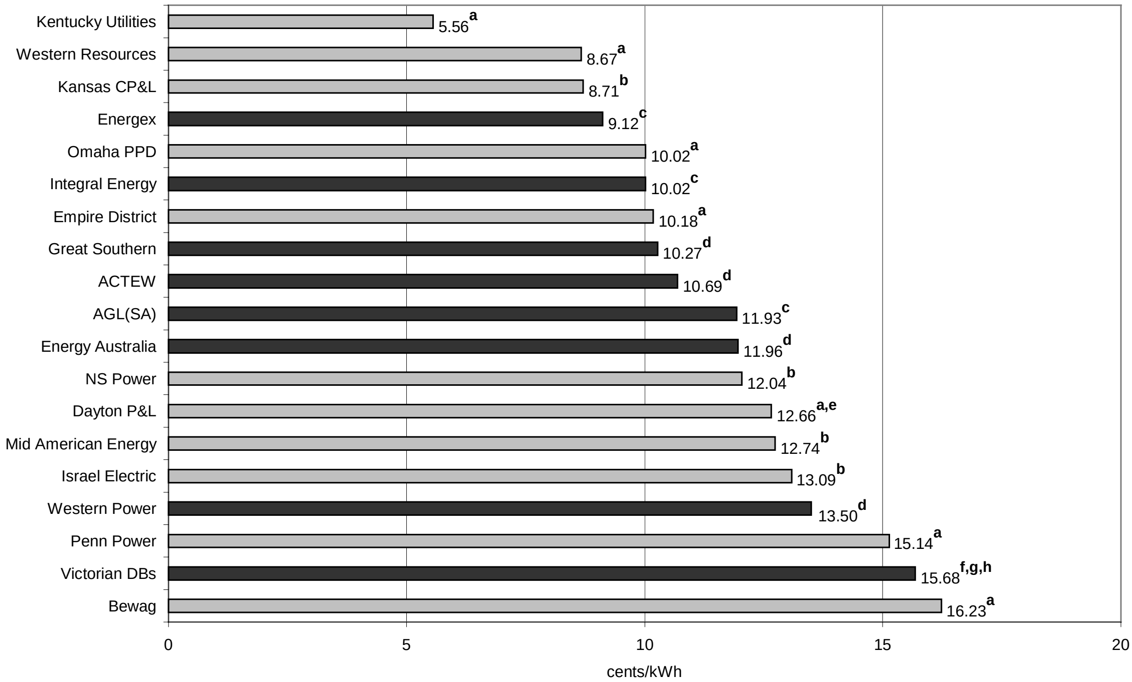
The results of the price comparisons for RB5 and RB6 are presented in figures 3.5 and 3.6.

In most cases, ESAA calculated average prices per kWh for the Australian utilities using time-of-use tariffs. For RB5, ESAA found the average price per kWh for the Victorian DBs to be lowest using the available standard domestic tariff.

Only four overseas utilities — Kansas CP&L, Israel Electric, Mid American Energy and NS Power — had time-of-use tariffs available. However, except for NS Power's average price per kWh for RB6, tariff structures other than time-of-use produced lower costs for RB5 and RB6 for these four utilities.

Flat rate tariffs, block tariffs and heating tariffs produced the lowest prices for the remaining overseas utilities. Consequently, the average price per kWh for some overseas utilities are the same for RB3 and RB5.

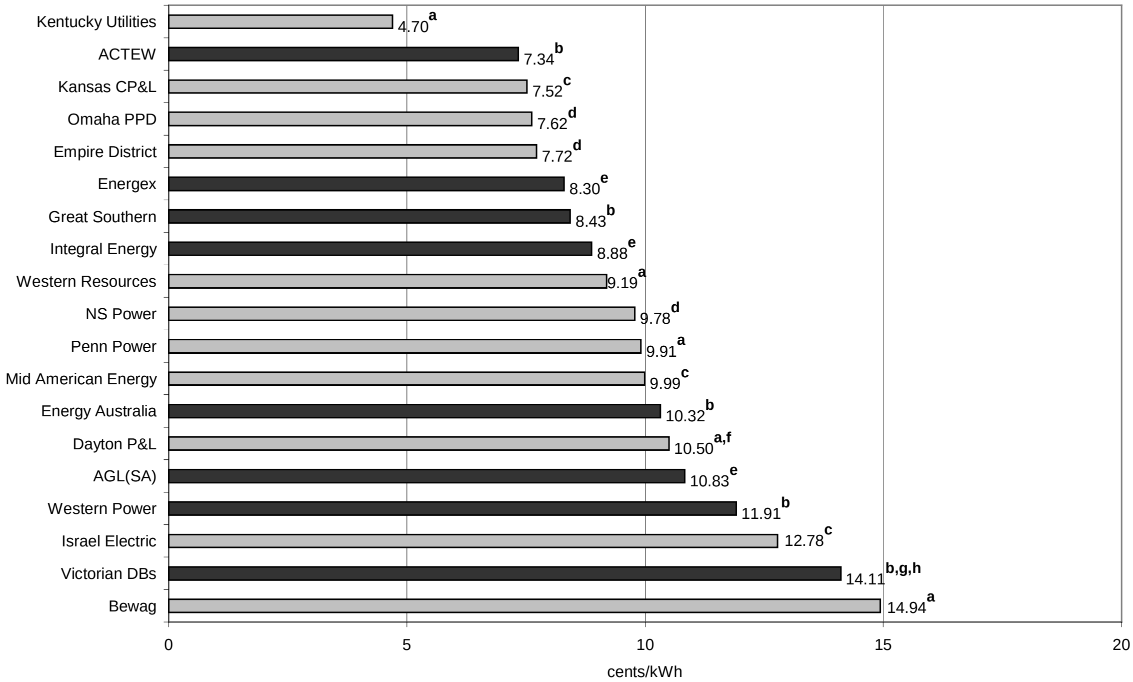
Figure 3.5 Unadjusted average price index: RB5, Australian dollars, October 2000



Note RB5 has a total annual consumption of 7500kWh, of which 2250kWh is consumed in off-peak periods. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Average prices per kWh were lowest using flat rate tariffs, block tariffs and off-peak heating tariffs. Time-of-use tariffs were unavailable. **b** Time-of-use tariffs were available, however, average prices per kWh were lower using an alternative tariff structure. **c** Average prices per kWh were lowest using an off-peak tariff rate. ESAA did not publish average prices for AGL(SA) and Energex as time-of-use tariffs were not available for these utilities. **d** ESAA based average prices per kWh for the Australian utilities on time-of-use tariffs. **e** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge. **f** ESAA used standard domestic tariffs rather than time-of-use tariffs to generate average prices per kWh for the Victorian DBs. **g** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **h** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs.

Data sources: ESAA (2000a); PC estimates.

Figure 3.6 **Unadjusted average price index: RB6, Australian dollars, October 2000**



Note RB6 has a total annual consumption of 20 000kWh, of which 8000kWh is consumed in off-peak periods. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Average price per kWh were lowest using flat rate tariffs, block tariffs and off-peak heating tariffs. Time-of-use tariffs were unavailable. **b** ESAA generated average prices per kWh for the Australian utilities using time-of-use tariffs. **c** Time-of-use tariffs were available, however, average prices were lower using an alternative tariff structure. **d** Time-of-use tariff produced lowest average price per kWh. **e** Average prices per kWh were lowest using an off-peak tariff rate. ESAA did not publish average prices for AGL(SA) and Energex as time-of-use tariffs were not available for these utilities. **f** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge. **g** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **h** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs.

Data sources: ESAA (2000a); PC estimates.

Where average prices did vary between RB3 and RB5, they tend to be higher for RB5 than RB3 even though annual consumption totalled 7500kWh in each bundle. Higher average prices may reflect the fact that, under RB5, only 30 per cent of annual consumption was subject to off-peak rates under a heating or time-of-use tariff. Under RB3, 40 per cent of annual consumption was subject to off-peak rates under a time-of-use or off-peak heating tariff.

Generally, average prices per kWh were lower for RB6 than RB5, possibly because access charges were spread over a higher total annual consumption.

3.3 Sensitivity analysis

The price comparisons are based on assumptions relating to the consumption bundles, load factors and the method used to convert overseas prices to Australian dollars. These assumptions were varied to test the robustness of the price comparisons for each consumption bundle. Comparisons are robust where variations in the assumptions do not lead to large changes in each utility's relative price performance.

Changing the consumption bundles

Three different sensitivity tests were performed to assess the impact of changing the consumption bundles.

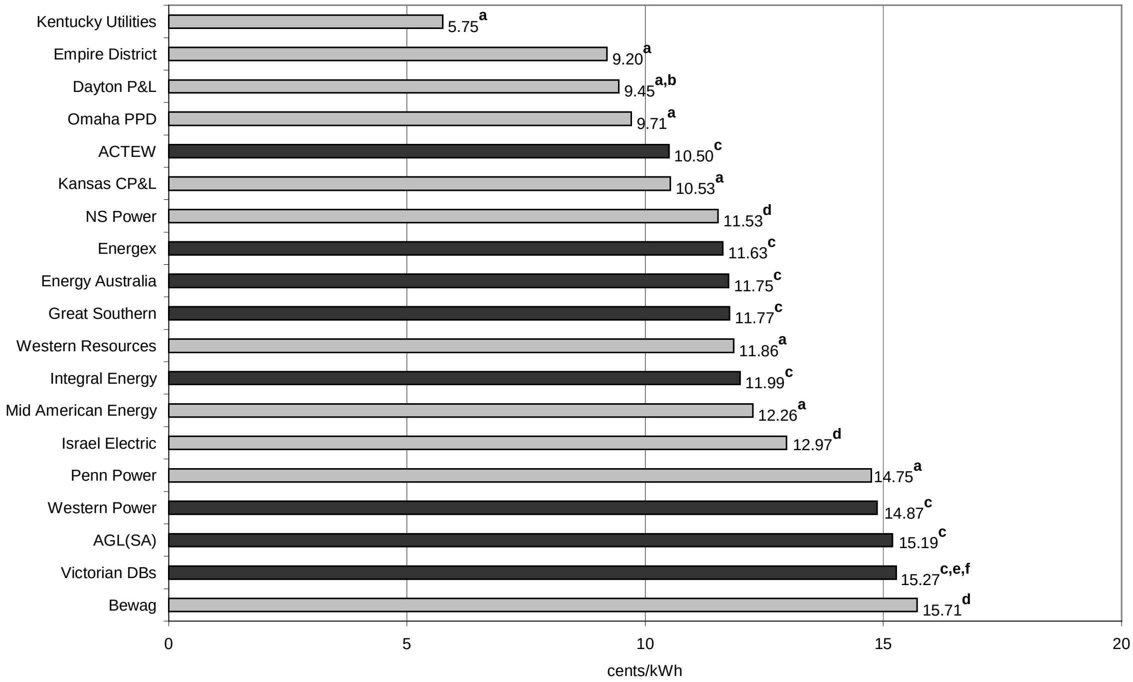
Increased annual consumption: Total annual consumption was increased to 10 000kWh and 20 000kWh, with no off-peak heating or time-of-use consumption, and compared to RB1 and RB2 (figures 3.7 and 3.8, compared to figures 3.1 and 3.2).

Increasing annual consumption from 1200kWh (RB1) to 10 000kWh and 20 000kWh produced a noticeable change in the rankings of the utilities, with the Australian utilities moving down the rankings. This movement may have been due to differences in the relative importance various utilities place on access charges as opposed to usage charges in their tariff structure.

There are number of factors that suggest this as an explanation. First, the same 10 utilities produced the most significant movement in both cases. Second, increasing the level of consumption from 7500kWh (RB2) to 10 000kWh and 20 000kWh did not produce a large change in the rankings. Third, increasing annual consumption from 10 000kWh to 20 000kWh did not produce a large change in the rankings, as access charges would have less of an influence at higher levels of consumption.

Alternatively, the shift in rankings may have been due to the more wide-spread use of block tariffs by the overseas utilities. Usage rates decline as consumption levels increase, reducing the unit cost of electricity.

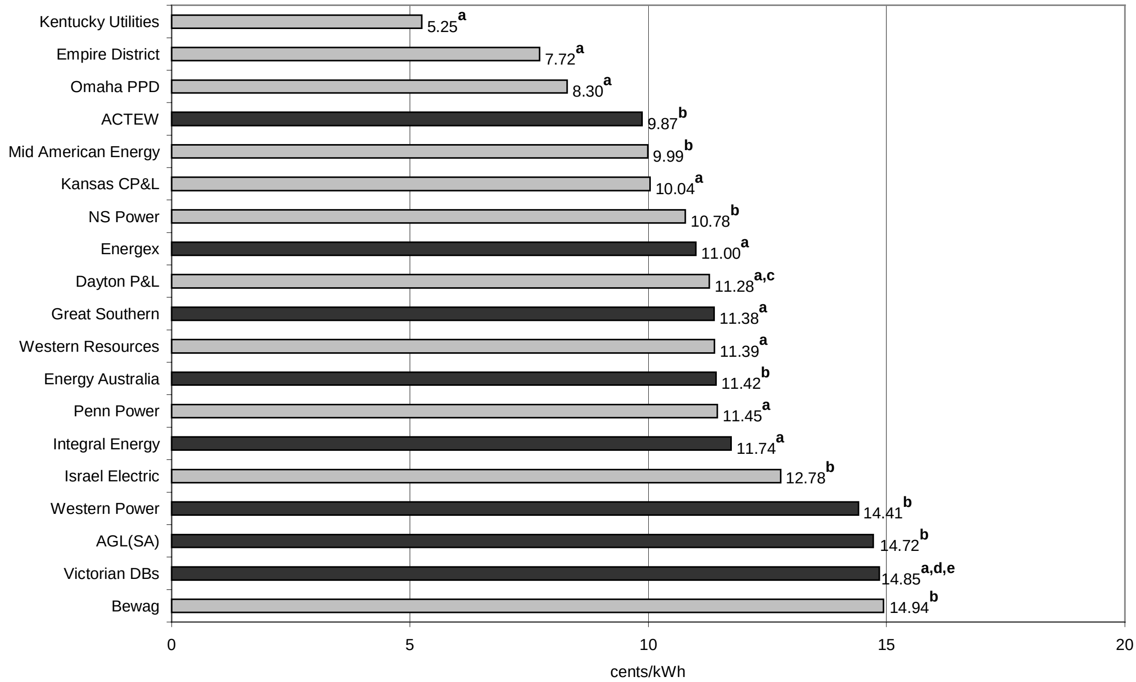
Figure 3.7 **Impact of changing total annual consumption, 10 000kWh, Australian dollars, October 2000**



Note Assumes a total annual consumption of 10 000kWh, with no off-peak heating or time-of-use consumption. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Block tariffs produced the lowest average price per kWh. **b** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge. **c** ESAA used the standard domestic tariff published by each utility to calculate Australian utility prices. Standard domestic tariffs are structured as either flat rate tariffs or block tariffs. **d** Flat rate tariffs produced the lowest average price per kWh. **e** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs.

Data sources: ESAA (2000); PC estimates.

Figure 3.8 **Impact of changing total annual consumption, 20 000kWh, Australian dollars, October 2000**



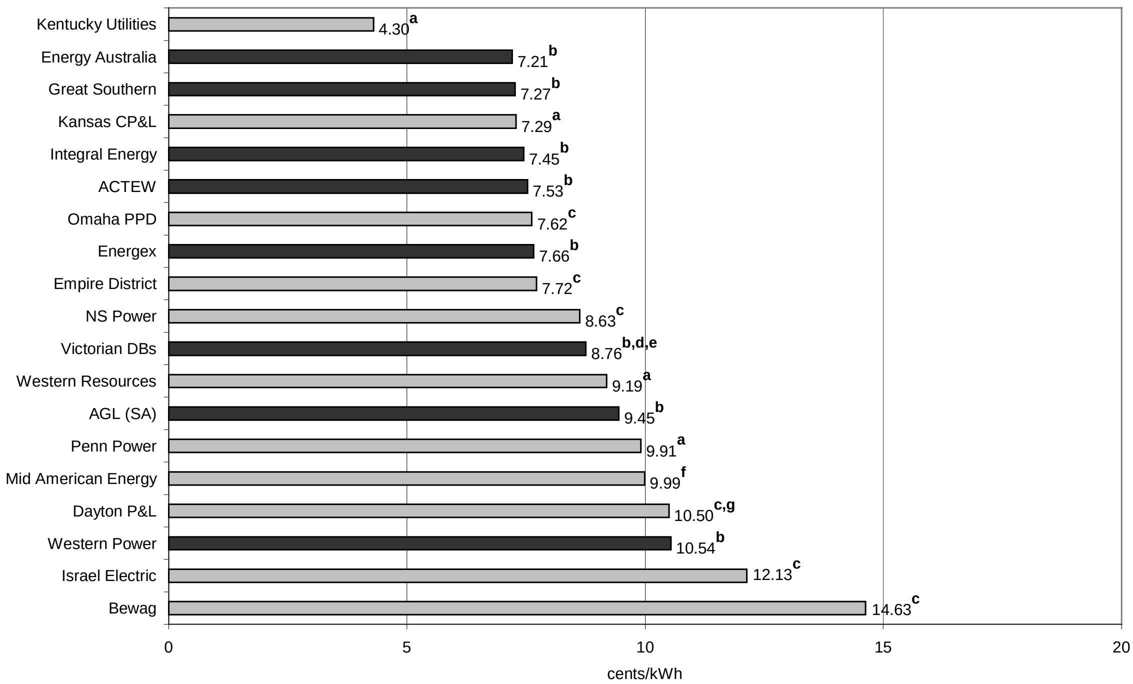
Note Assumes a total annual consumption of 20 000kWh, with no off-peak heating or time-of-use consumption. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Block tariffs produced the lowest average price per kWh. **b** Flat rate tariffs produced the lowest average price per kWh. **c** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge. **d** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL (Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used as representative of all five DBs.

Data source: PC estimates.

Increasing the proportion of off-peak heating: For RB3 and RB4, it was assumed that 40 per cent of total annual consumption was subject to a heating tariff. Increasing the proportion to 60 per cent improved the relative rankings of the Australian utilities (see figure 3.9, compared with figure 3.4).

This is most likely due to the fact that few of the overseas utilities had off-peak heating tariffs available, and block tariffs, flat rate tariffs or time-of-use tariffs were used to calculate average prices. Consequently, as the proportion of annual consumption subject to an off-peak heating tariff increased, the relative rankings of the Australian utilities improved as the average price per kWh for many of the overseas utilities did not vary. This is supported by the fact that the relative ranking of the Australian utilities compared to those overseas utilities that did have heating tariffs available did not change significantly.

Figure 3.9 Impact of changing the proportion of off-peak heating consumption, Australian dollars, October 2000

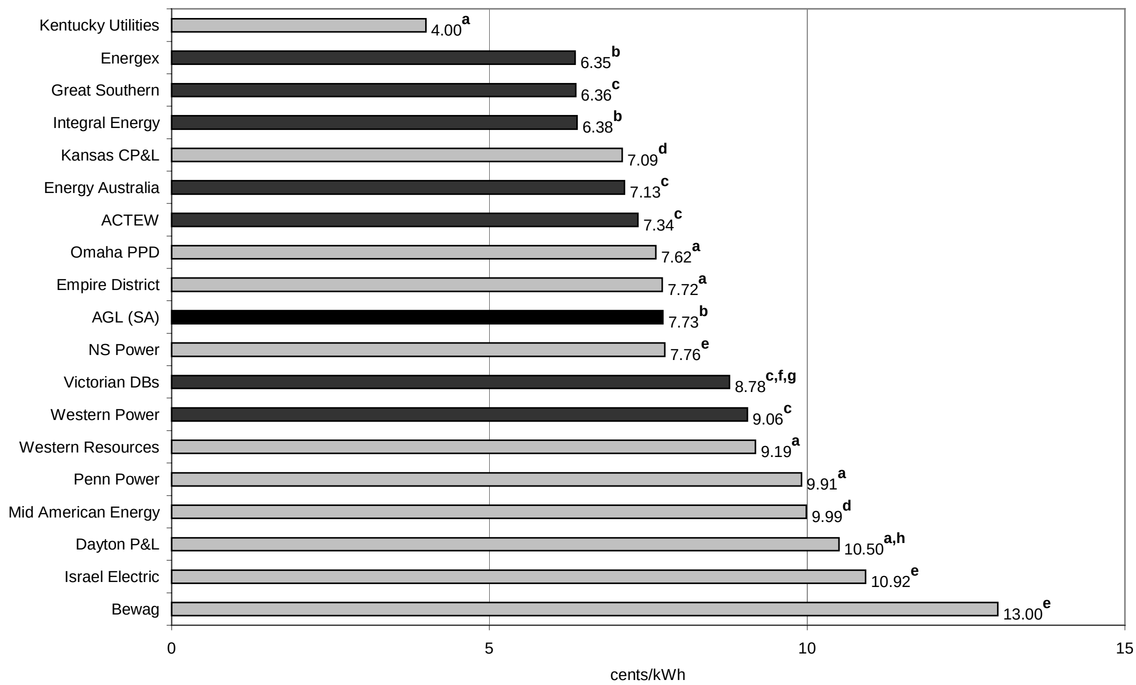


Note Assumes at total annual consumption of 20 000kWh with 12 000kWh subject to a heating tariff. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Heating tariffs produced the lowest average prices per kWh. **b** ESAA used domestic off-peak heating tariffs in conjunction with the standard domestic tariff to calculate average prices for each of the Australian utilities. **c** Average prices per kWh were lowest using either a time-of-use tariff, block tariff or a flat rate tariff. Heating tariffs were unavailable. **d** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs. **f** Heating tariffs were available but block tariffs produced a lower average price per kWh. **g** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge.

Data sources: ESAA (2000a); PC estimates.

Increasing the proportion of off-peak consumption under time-of-use tariff: For RB5 and RB6, it was assumed that 30 and 40 per cent of total annual consumption was subject to off-peak rates under a time-of-use tariff. Increasing this proportion to 75 per cent improved the overall ranking of the Australian utilities (see figure 3.10, compared with figure 3.6). This was most likely due to the fact that few of the overseas utilities had time-of-use tariffs available.

Figure 3.10 **Impact of changing the proportion of consumption subject to time-of-use, Australian dollars, October 2000**



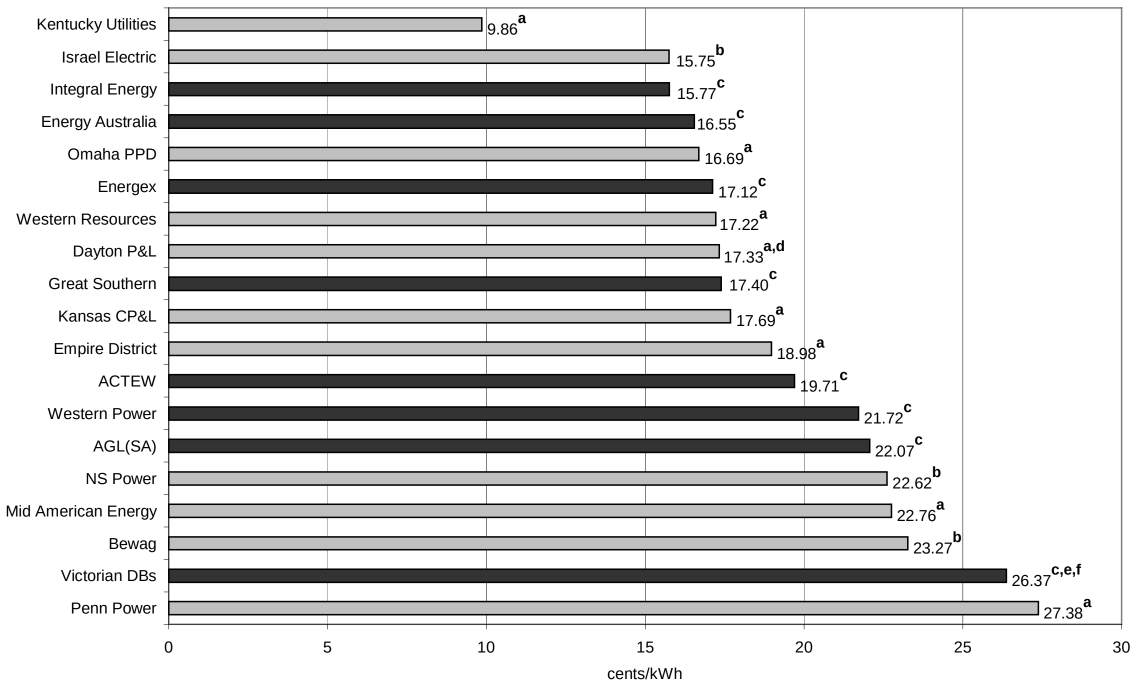
Note Assumes a total annual consumption of 20 000kWh, of which 15 000kWh is consumed in off-peak periods. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Flat rate, block or off-peak heating tariffs produced the lowest average price per kWh. Time-of-use tariff were not available. **b** Average prices per kWh were lowest using an off-peak tariff rate. ESAA did not publish average prices for AGL(SA) and Energex as time-of-use tariffs were not available for these utilities. **c** ESAA generated average prices per kWh for the Australian utilities using time-of-use tariffs. **d** Time-of-use tariff was available but a block or off-peak heating tariff produced a lower average price per kWh. **e** Time-of-use tariff produced the lowest average price per kWh. **f** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **g** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs. **h** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge.

Data sources: ESAA (2000a); PC estimates.

Impact of changing the load factor assumption

For the price comparisons in section 3.2, a load factor of 50 per cent was assumed. This assumption was varied to include a load factor of 30 per cent and 70 per cent to test whether load factor affected the comparisons. Adjusting the load factor assumption had only a minor effect upon the relative rankings of the utilities (see figures 3.11 and 3.12).

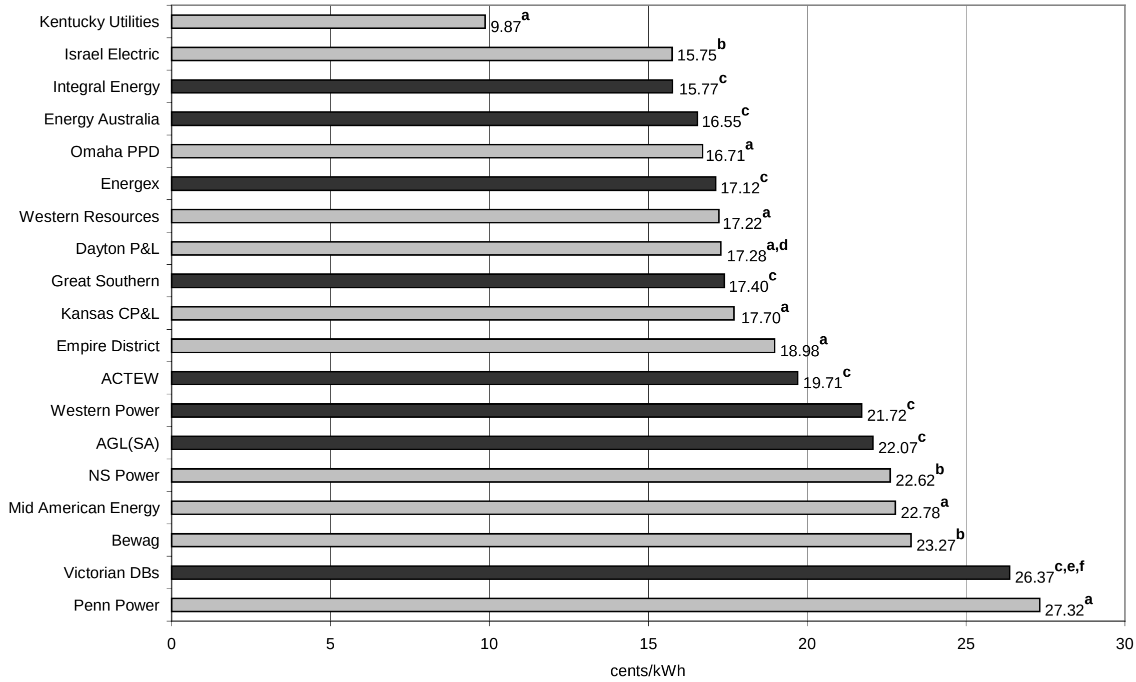
Figure 3.11 **Impact of changing the load factor to 30 per cent, RB1, Australian dollars, October 2000**



Note RB1 has a total annual consumption of 1200kWh, with no off-peak heating or time-of-use consumption. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Block tariffs produced the lowest average price per kWh. **b** Flat rate tariffs produced the lowest average price per kWh. **c** The standard domestic tariff published by each utility was used to calculate Australian utility prices. Standard domestic tariffs are structured as either flat rate tariffs or block tariffs. **d** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge. **e** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used as representative of all five DBs.

Data source: PC estimates.

Figure 3.12 **Impact of changing the load factor to 70 per cent, RB1, Australian dollars, October 2000**



Note RB1 has a total annual consumption of 1200kWh, with no off-peak heating or time-of-use consumption. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Block tariffs produced the lowest average price per kWh. **b** Flat rate tariffs produced the lowest average price per kWh. **c** The standard domestic tariff published by each utility was used to calculate Australian utility prices. Standard domestic tariffs are structured as either flat rate tariffs or block tariffs. **d** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge. **e** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used as representative of all five DBs.

Data source: PC estimates.

Changing the load factor for the other bundles produced a similar result, with little or no change to the price rankings.

Impact of changing the basis for currency conversion

The initial price comparisons were made on a currency conversion method based upon PPP rates. The price comparisons were recalculated using market exchange rates as the basis of conversion. The exchange rate used for each country is the exchange rate at 31 October 2000 (table 3.4).

Table 3.4 **Market exchange rates; 31 October 2000**

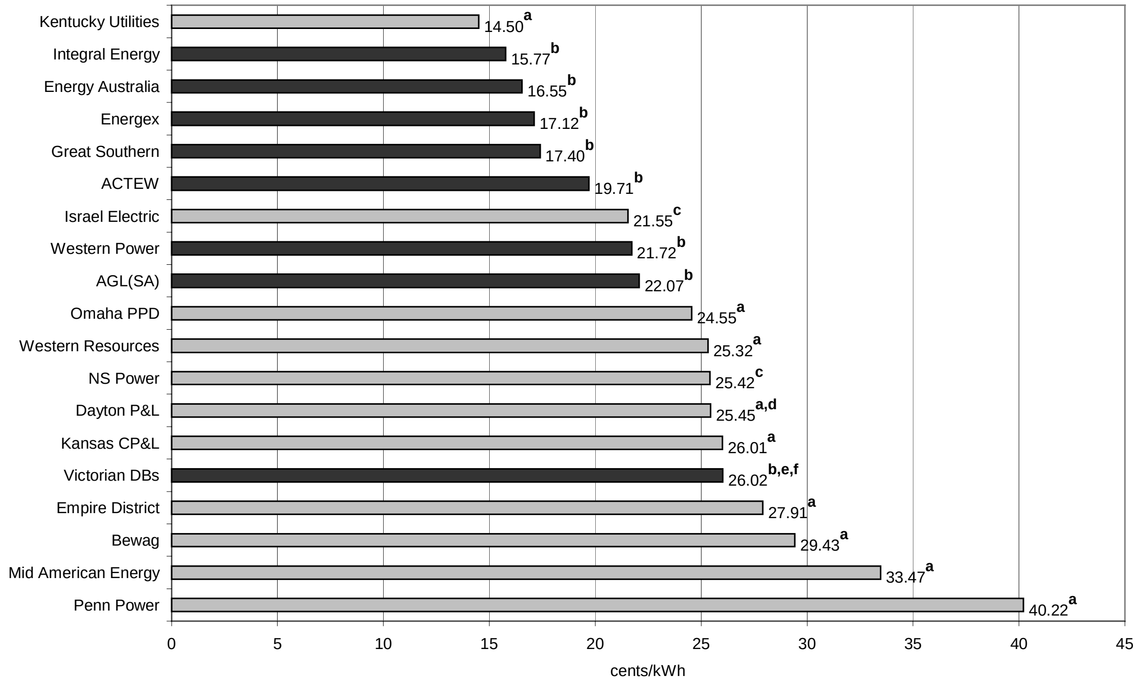
Country	*Market exchange rate*
	Unit currency per A$
Australia	1.0000
Canada	0.8008
Germany	1.2163
Israel	2.1630
United States	0.5232

Note: The exchange rates listed are the median asking price for 31 October 2000. Estimated prices are based on the daily US dollar rates. On 31 October 2000, the minimum price for A$ dollars was US$0.5220 and the maximum price was US$0.5272.

Source: Oanda, http://www.oanda.com, 12 December 2000.

The effect of using market exchange rates instead of PPPs was to improve Australia's ranking because of the relatively low value of the Australian dollar in October 2000 (see figures 3.13 to 3.18). However, as discussed previously, the use of market exchange rates for currency conversion would render the price comparisons subject to factors external to the electricity industry.

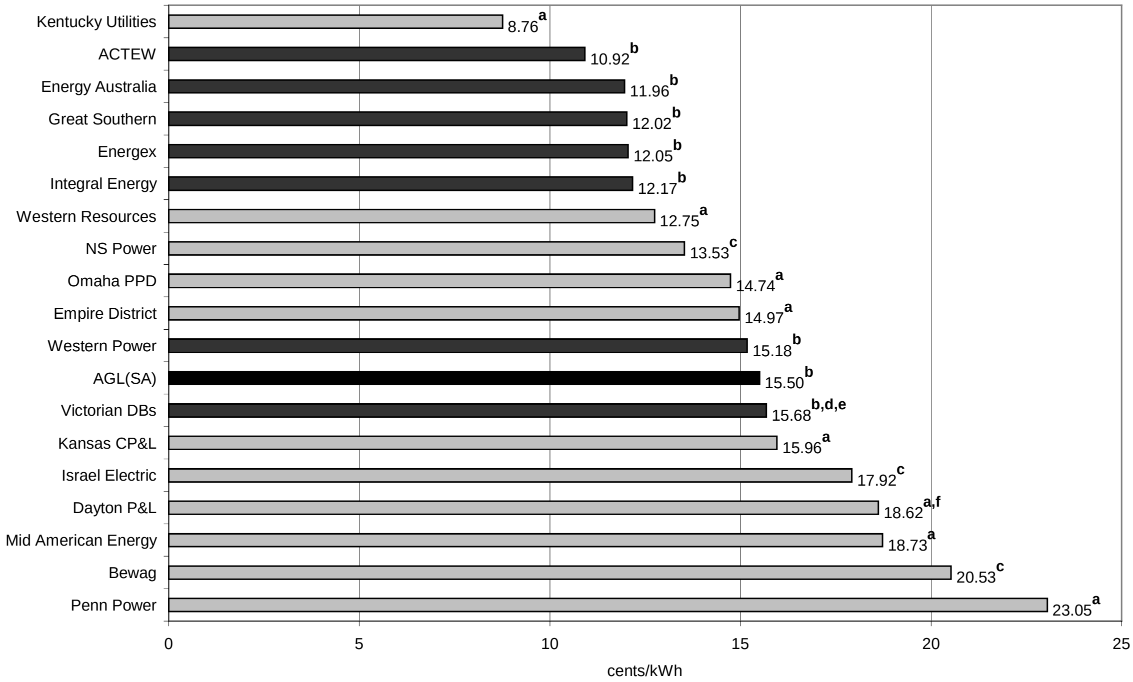
Figure 3.13 **Impact of using market exchange rates, RB1, Australian dollars, October 2000**



Note: RB1 has a total annual consumption of 1200kWh, with no off-peak heating or time-of-use consumption. Prices are converted to a A$ using market exchange rates applicable at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Block tariffs produced the lowest average price per kWh. **b** ESAA used the standard domestic tariff published by each utility to calculate Australian utility prices. Standard domestic tariffs are structured as either flat rate tariffs or block tariffs. **c** Flat rate tariffs produced the lowest average price per kWh. **d** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge. **e** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs.

Data sources: ESAA (2000a); PC estimates.

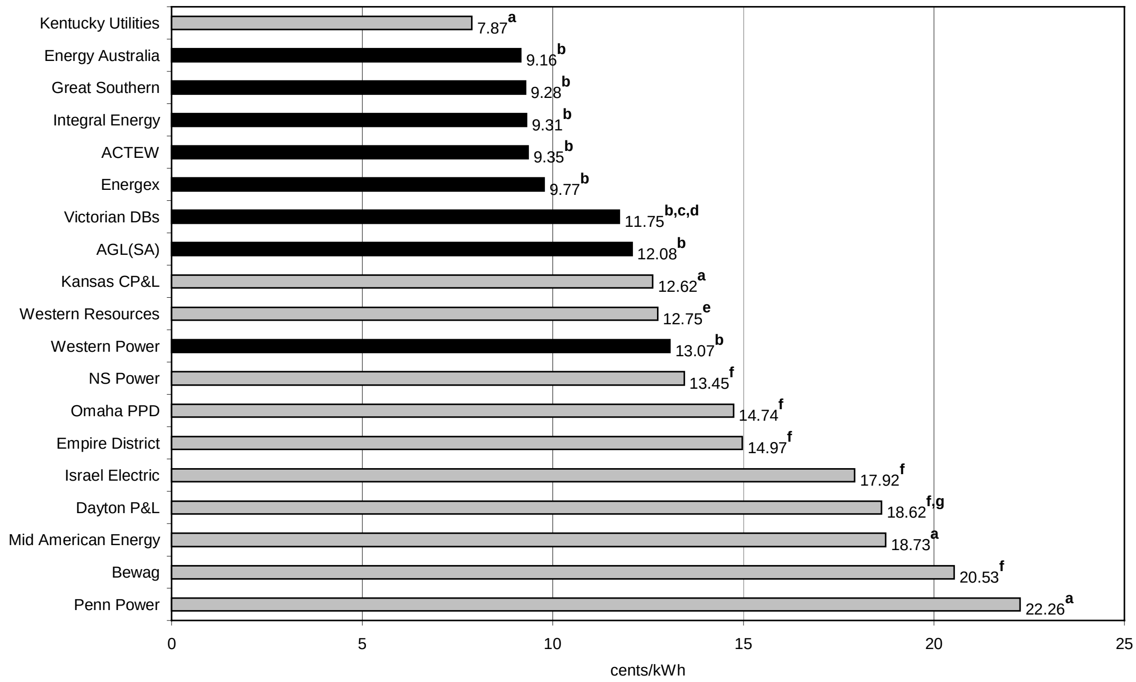
Figure 3.14 **Impact of using market exchange rates, RB2, Australian dollars, October 2000**



Note RB2 has a total annual consumption of 7500kWh, with no off-peak heating or time-of-use consumption. Prices are converted to a A$ using market exchange rates applicable at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Block tariffs produced the lowest average price per kWh. **b** ESAA used the standard domestic tariff published by each utility to calculate Australian utility prices. Standard domestic tariffs are structured as either flat rate tariffs or block tariffs. **c** Flat rate tariffs produced the lowest average price per kWh. **d** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs. **f** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge.

Data sources: ESAA (2000a); PC estimates.

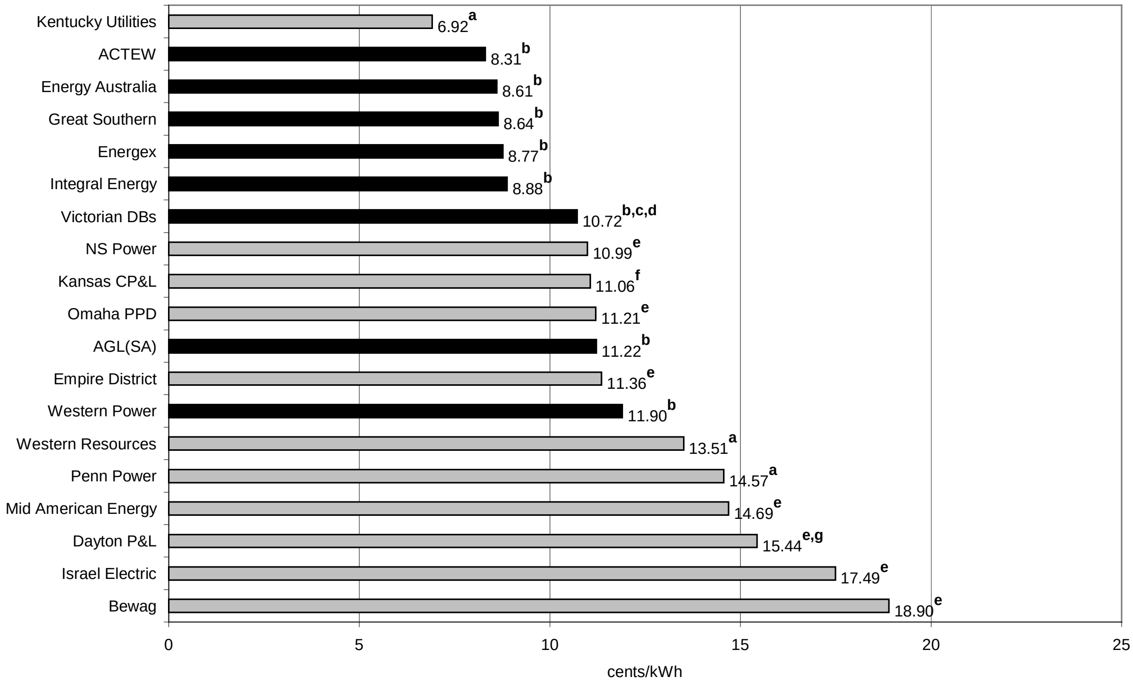
Figure 3.15 **Impact of using market exchange rates, RB3, Australian dollars, October 2000**



Note RB3 has a total annual consumption of 7500kWh, of which 3000kWh is used in either hot water or space heating. Prices are converted to a A$ using market exchange rates applicable at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Heating tariffs produced the lowest average prices per kWh for each utility. **b** ESAA used domestic off-peak heating tariffs in conjunction with the standard domestic tariff to calculate average prices for each of the Australian utilities. **c** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **d** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs. **e** Heating tariff available but block tariff produced a lower average price per kWh. **f** Average prices per kWh were lowest using either a time-of-use tariff, block tariff or a flat rate tariff. Heating tariffs were unavailable. **g** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge.

Data sources: ESAA (2000a); PC estimates.

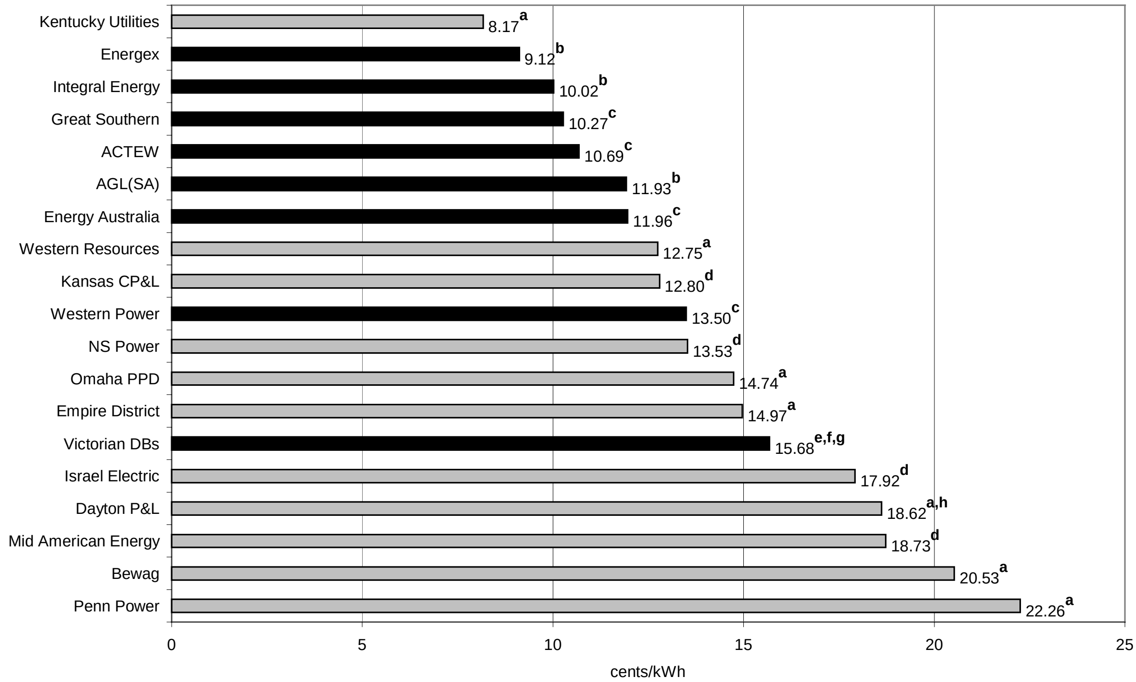
Figure 3.16 **Impact of using market exchange rates, RB4, Australian dollars, October 2000**



Note RB4 has a total annual consumption of 20 000kWh, of which 8000kWh is used in either hot water or space heating. Prices are converted to a A$ using market exchange rates applicable at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Heating tariffs produced the lowest average prices per kWh. **b** ESAA used domestic off-peak heating tariffs in conjunction with the standard domestic tariff to calculate average prices for each of the Australian utilities. **c** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **d** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs. **e** Average prices per kWh were lowest using either a time-of-use tariff, block tariff or a flat rate tariff. Heating tariffs were unavailable. **f** Heating tariff was available but block tariff produced a lower average price per kWh. **g** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge.

Data sources: ESAA (2000a); PC estimates.

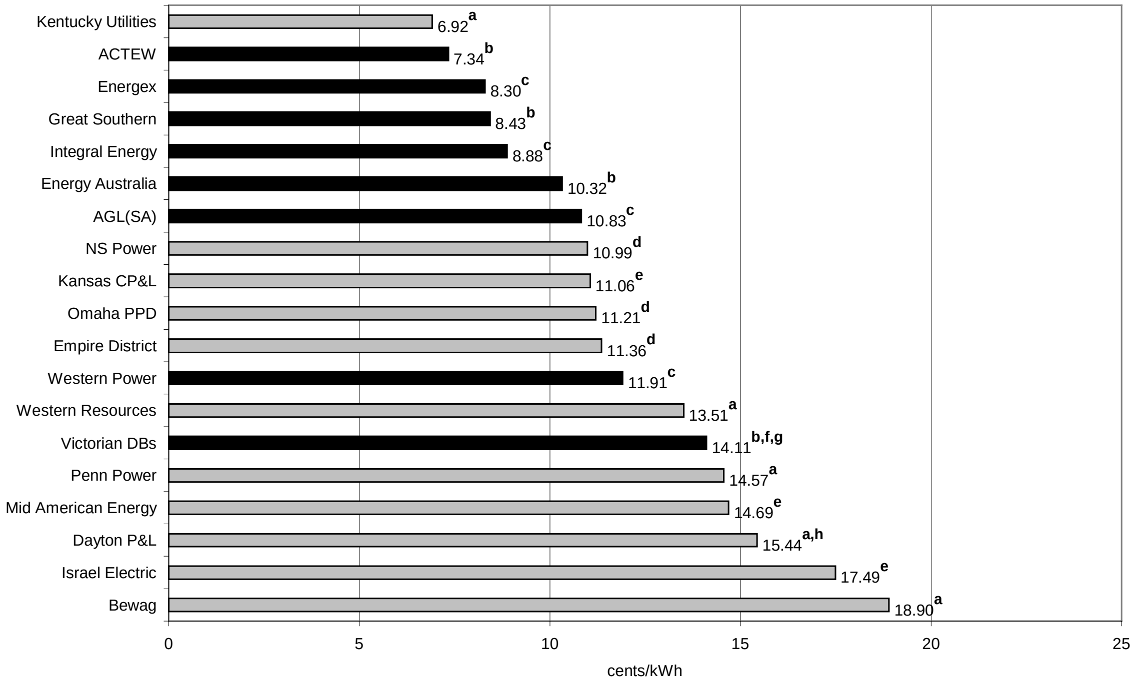
Figure 3.17 **Impact of using market exchange rates, RB5, Australian dollars, October 2000**



Note RB5 has a total annual consumption of 7500kWh, of which 2250kWh is consumed in off-peak periods. Prices are converted to a A$ using market exchange rates applicable at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Average prices per kWh were lowest using flat rate tariffs, block tariffs and off-peak heating tariffs. Time-of-use tariffs were unavailable. **b** Average prices per kWh were lowest using an off-peak tariff rate. ESAA did not publish average prices for AGL(SA) and Energex as time-of-use tariffs were not available for these utilities. **c** ESAA based average prices per kWh for the Australian utilities on time-of-use tariffs. **d** Time-of-use tariffs were available, however, average prices per kWh were lower using an alternative tariff structure. **e** ESAA used standard domestic tariffs rather than time-of-use tariffs to generate average prices per kWh for the Victorian DBs. **f** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **g** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor's average price per kWh as representative of all five DBs. **h** Dayton P&L's customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge.

Data sources: ESAA (2000a); PC estimates.

Figure 3.18 **Impact of using market exchange rates, RB6, Australian dollars, October 2000**



Note RB6 has a total annual consumption of 20 000kWh, of which 8000kWh is consumed in off-peak periods. Prices are converted to a A$ using market exchange rates applicable at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Average price per kWh were lowest using flat rate tariffs, block tariffs and off-peak heating tariffs. Time-of-use tariffs were unavailable. **b** ESAA generated average prices per kWh for the Australian utilities using time-of-use tariffs. **c** Average prices per kWh were lowest using an off-peak tariff rate. ESAA did not publish average prices for AGL(SA) and Energex as time-of-use tariffs were not available for these utilities. **d** Time-of-use tariff produced lowest average price per kWh. **e** Time-of-use tariffs were available, however, average prices were lower an alternative tariff structure. **f** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **g** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA used Powercor’s average price per kWh as representative of all five DBs. **h** Dayton P&L’s customers may be billed either with or without monthly consumption. Average prices were lowest by assuming that consumption is billed monthly as this reduced the monthly access charge.

Data sources: ESAA (2000a); PC estimates.

Impact of revised Victorian tariff schedule

On 1 January 2001, a new residential tariff schedule was introduced for the Victorian DBs. Table 3.5 indicates that the unit prices introduced under this revised schedule did not have a large impact on their relative rankings.

Table 3.5 **Unadjusted average price index for revised Victorian tariffs: RB1 to RB6, Australian dollars, October 2000 and January 2001**

Consumption bundle	*Unrevised unadjusted prices October 2000*	*Revised unadjusted prices January 2001*
	cents/kWh	cents/kWh
RB1	26.02	26.37
RB2	15.68	15.89
RB3	11.75	11.91
RB4	10.72	10.87
RB5	15.68[a]	15.89[b]
RB6	14.11	14.29

Note Prices include federal, state and/or local taxes where applicable. Prices for Victorian DBs were calculated using tariffs rates applicable at 1 January 2001. In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.9 per cent. Powercor's average price per kWh were used as representative of all five DBs. **a** ESAA used standard domestic tariffs rather than time-of-use tariffs to generate average prices per kWh as the standard domestic tariff produced a lower average price. **b** Average price per kWh calculated using the standard domestic tariff as it produced a lower average price than the relevant time-of-use tariff.

Sources: ESAA (2000a); PC estimates.

3.4 In summary

Price comparisons of the kind presented in this chapter are inevitably based on assumptions. Although these introduce an element of subjectivity into the price comparisons, there is nevertheless a reasonable basis for making the following broad conclusions:

- There was a wide dispersion in the relative prices of the utilities studied.
- Increasing annual consumption generally results in a decreased unit cost of electricity.

That said, these conclusions are based on price comparisons that are unadjusted for cost factors outside the control of the industry in the short-run. In particular, utility-specific taxes, such as environmental taxes, have been included in the comparisons and these are likely to have a significant impact on price relativities.

The comparisons drawn are not greatly affected by changes in assumptions about the consumption bundles or load factor used. However, the relatively low value of Australia's dollar at October 2000 improved the ranking of Australian utilities relative to those overseas, if the price comparisons are based on market exchange rates.

4 Unadjusted small to medium business prices

Business demand for electricity depends on a number of factors, including the industry in which the business operates and its size. These characteristics also have a significant influence on the price paid by business for electricity.

In this chapter, Australian and overseas electricity prices are compared for typical patterns of electricity usage for small and medium-sized businesses. These prices were calculated using the tariff schedules of electricity suppliers. Electricity prices paid by residential customers were presented in chapter 3, while those paid by large businesses are presented in chapter 5.

Electricity prices are often affected by cost factors outside the control of the electricity supplier. In this chapter, prices have not been adjusted to allow for the effect of these cost factors. Cost factors outside the control of industry are examined in chapter 7.

4.1 Methodology

Average prices in cents per kiloWatt hour (cents/kWh) paid by small and medium-sized businesses for the supply of electricity over one year were calculated, for a number of Australian and overseas electricity distributors using tariff rates applicable at October 2000.

Information on the methodology underlying the calculation of electricity prices is presented in the discussion on residential prices (see chapter 3). Where the methodology or assumptions underlying the calculation of final prices for small and medium sized businesses differed, these differences are noted.

Small and medium business consumption bundles

In this study, the small and medium business bundles chosen as a basis for comparison are a subset of those used by the Electricity Supply Association of Australia (ESAA) in its publication, *Electricity Prices in Australia, 2000/2001* (see table 4.1). The bundles are considered sufficiently wide-ranging in scope to be representative of small and medium business consumption patterns in Australia and the other countries studied (see chapter 1).

Six consumption bundles were developed, two for small business and four for medium-sized business (see table 4.1).

Table 4.1 **Small and medium-sized business consumption bundles**

Class	*Bundle name*	*Peak demand*	*Load factor*	*Percentage of consumption in off-peak periods*[a]	*Annual consumption*
		kW	per cent	per cent	MWh
Small business	SB1	11	60	46.5	60
	SB2	23	30	28.5	60
Medium business	MB1	100	30	28.5	263
	MB2	100	60	46.5	526
	MB3	250	30	28.5	657
	MB4	250	60	46.5	1 314

a Where a utility offers off-peak rates for a different number of hours to that assumed by the ESAA, these percentages are adjusted accordingly.

Source: ESAA (2000a).

The characteristics that define these bundles are:

- *Peak demand* — the maximum electrical load in a period of time. The six bundles have maximum demand of between 11 and 250kW.
- *Load factor* — the ratio of average demand to peak demand during a period of time, expressed as a percentage. Load factor indicates the intensity of electricity use. The load factors chosen for the bundles were 30 and 60 per cent.
- *Annual consumption* — annual consumption of the six bundles ranges between 60 and 1314MWh.
- *Percentage of consumption in off-peak periods*.

Peak demand, load factor and annual consumption are related. Fixing the value of two of these variables determines the third according to the following formula:

*Annual consumption (MWh) = 24 hours * 365 days * Peak demand (MW) * Load factor (per cent)*

Hence, two businesses that have the same peak demand may consume different amounts of electricity in a year because the intensity at which they consume that electricity (load factor) may vary. For example, consumption bundles MB1 and MB2 have the same peak demand. However, the level of annual consumption differs because of the more intensive use of electricity for MB2.

ESAA (2000a) assumptions on the proportion of electricity used in off-peak periods were used (see table 4.2). The level of off-peak consumption is related to load factor. As load factor increases, the proportion of electricity consumed during off-peak periods increases.

Table 4.2 **Proportion of off-peak energy consumption for selected load factors**

Load factor	*Proportion of off-peak energy consumption*[a]
per cent	per cent
30	28.5
60	46.5

[a] These percentages apply for peak demands of up to 1000kW and assumes the duration of the off-peak period is 98 hours per week. The percentages are adjusted accordingly where the tariff of an electricity supplier applies for a different number of hours.

Source: (ESAA 2000a.)

Contestable and non-contestable customers in Australia

As at October 2000, most business customers that consume more than 160MWh annually were deemed to be ‘contestable’.[1] Remaining customers are known as ‘franchise’ or non-contestable customers. These non-contestable customers must purchase electricity from their incumbent retailer.

The two small business bundles (see table 4.1) comprise annual consumption levels of less than 160MWh, and thus are considered non-contestable customers.

The medium business bundles include levels of annual consumption that exceed the 160MWh threshold and thus some users consuming at these levels may be contestable. However, there is anecdotal evidence that most small to medium-sized businesses (whose electricity requirements are typical of the four bundles) have remained with their incumbent supplier on their existing tariff. Average prices per kWh for each of these bundles were calculated using franchise customer tariff schedules.

Where medium businesses have decided to negotiate rates, the average prices they pay may be more favourable than under published tariffs. In chapter 5, an alternative methodology is used to estimate the electricity prices paid by Australian businesses that purchase electricity in the contestable market.

1 The threshold of 160MWh applies to businesses in New South Wales, Victoria and the Australian Capital Territory. The thresholds in Queensland, South Australia and Western Australia are 200MWh, 750MWh and 8760MWh respectively.

Calculation of average prices

As in chapters 3 and 5, the reported prices are those that minimise the cost to the customer of the specified bundle of electricity. For example, where a customer has a choice of three types of tariffs, the tariff that minimises the cost to the customer is used.

The tariff schedules used to calculate average prices for each consumption bundle are listed in appendix C.

Taxes

From the perspective of the customer, it is desirable to include all taxes in the comparisons because they are included in the prices customers pay. This applies to price comparisons for business as well as for residential customers.

In countries where indirect taxes take the form of Value-Added Taxes (VAT) or Goods and Services Taxes (GST), businesses may not pay tax on the electricity they purchase. Alternatively, they may pay tax and receive a rebate for the tax paid. However, a tax on the value of these services is ultimately included in the prices paid by the customers of final goods and services. Such taxes therefore affect the demand for final goods and services and hence the demand for electricity.

Government imposts, such as taxation, are discussed in chapter 7.

Currency conversion

As in chapter 3, Purchasing Power Parities (PPPs) were used to compare electricity prices for businesses using Australian dollars as a common unit of account. The comparisons using PPP rates indicate how the price of electricity (expressed as an index) varies across countries in relation to the general price level. More detail on the PPP methodology is presented in chapter 3.

4.2 Prices

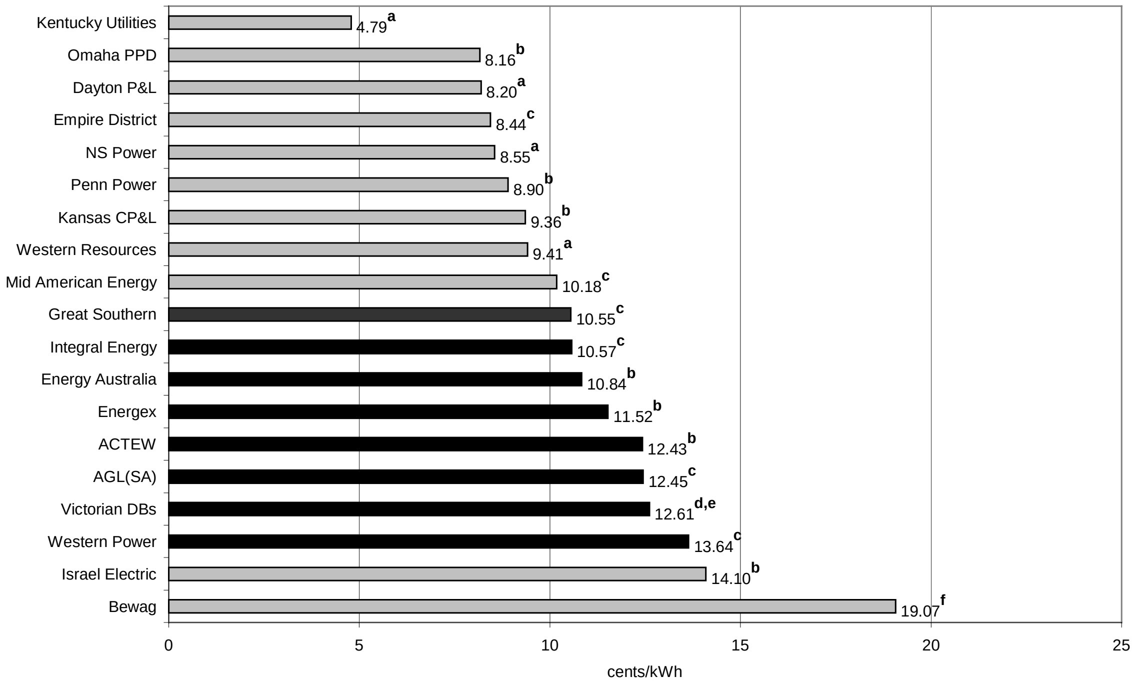
Relative prices were calculated for the six electricity bundles outlined in table 4.1. The prices have been calculated for a one year period, with the fixed charges (where applicable) included in the price calculations.[2] As noted above, these prices are unadjusted, meaning that no adjustment has been made for the effect of cost factors outside the control of the electricity supplier.

2 In this way, fixed charges are spread over a full year’s consumption of electricity.

Consumption bundle SB1

A comparison of the average price per kWh paid for consumption patterns typical of SB1 are shown in figure 4.1. SB1 represents a business with a relatively low level of annual consumption of 60MWh.

Figure 4.1 **Unadjusted average price index for SB1, Australian dollars, October 2000**



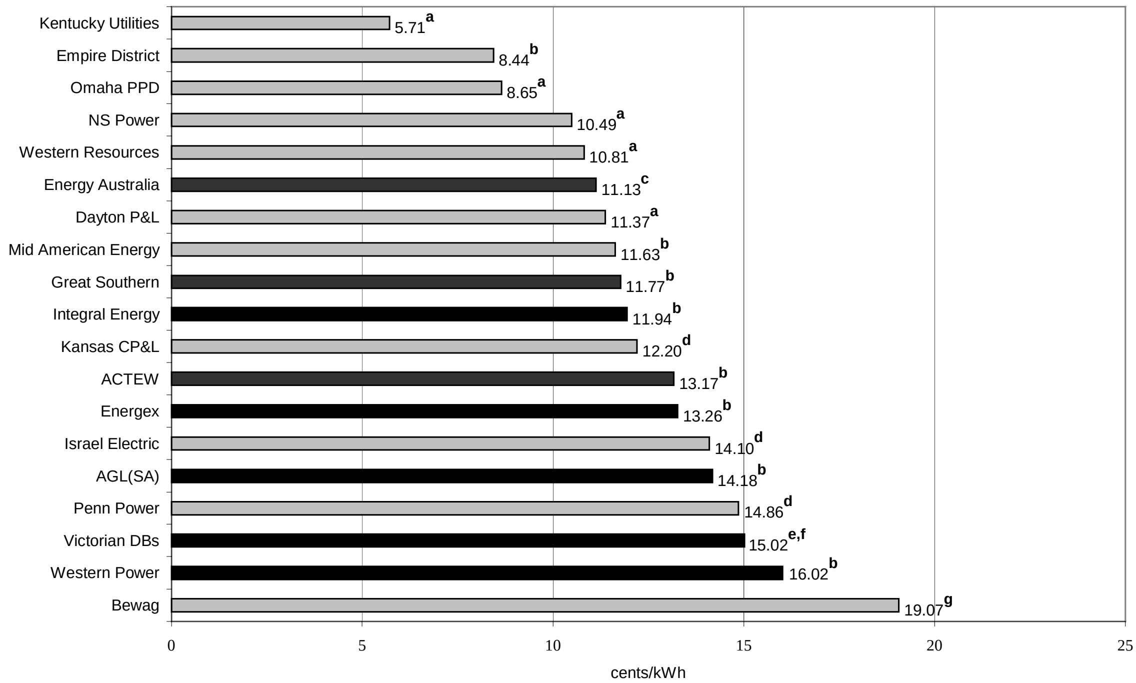
Note SB1 has a peak demand of 11kW, a load factor of 60 per cent, a percentage of off-peak consumption of 46.5 per cent and an annual consumption of 60MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** Block tariffs produced the lowest average price per kWh. **c** Time-of-use tariffs produced the lowest average price per kWh. **d** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used to represent all five DBs. **f** The lowest average price per kWh is based on a 24 month flat rate tariff.

Data source: PC estimates.

Consumption bundle SB2

The results of the price comparisons for SB2 are presented in figure 4.2. SB2 differs from SB1 in that, under SB2, the load factor decreases to 30 per cent. For a given annual consumption of 60MWh, decreasing the load factor increases peak demand to 23kW and reduces off-peak demand to 28.5 per cent (see table 4.2).

Figure 4.2 **Unadjusted average price index for SB2, Australian dollars, October 2000**



Note SB2 has a peak demand of 23kW, a load factor of 30 per cent, a percentage of off-peak consumption of 28.5 per cent and an annual consumption of 60MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** Time-of-use tariffs produced the lowest average price per kWh. **c** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **d** Block tariffs produced the lowest average price per kWh. **e** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used to represent all five DBs. **g** The lowest average price per kWh is based on a 24 month flat rate tariff.

Data source: PC estimates.

Decreasing the load factor has the effect of increasing the average price per kWh for most distributors, even though annual consumption remains the same. The reasons for this effect include:

- there is a decline in the use of cheaper off-peak electricity; and
- in some cases, the demand charge, which escalates with peak demand, increases.

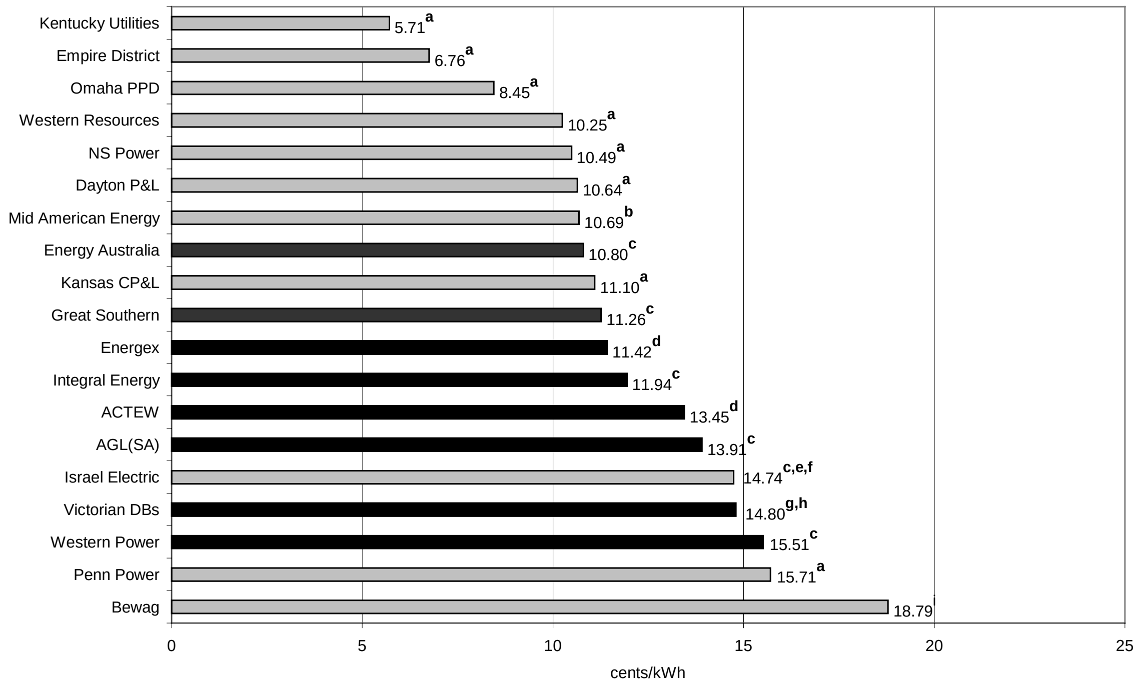
For example, the small increase in Integral Energy's average price is due to lower utilisation of off-peak electricity. On the other hand, the increase in Penn Power's average price was because the (high) demand charge is levied on a greater level of peak demand.

The change in average prices per kWh between SB1 and SB2 highlights that for many utilities, time-of-use and demand charges, and not just the amount of electricity consumed, can substantially affect electricity prices.

Consumption bundle MB1

The results of the price comparisons for MB1 are presented in figure 4.3. There is little variation in each utility's relative ranking between MB1 and SB2, even though the absolute level of average prices changed. This is because MB1 and SB2 have the same load factor and percentage of off-peak usage.

Figure 4.3 **Unadjusted average price index for MB1, Australian dollars, October 2000**



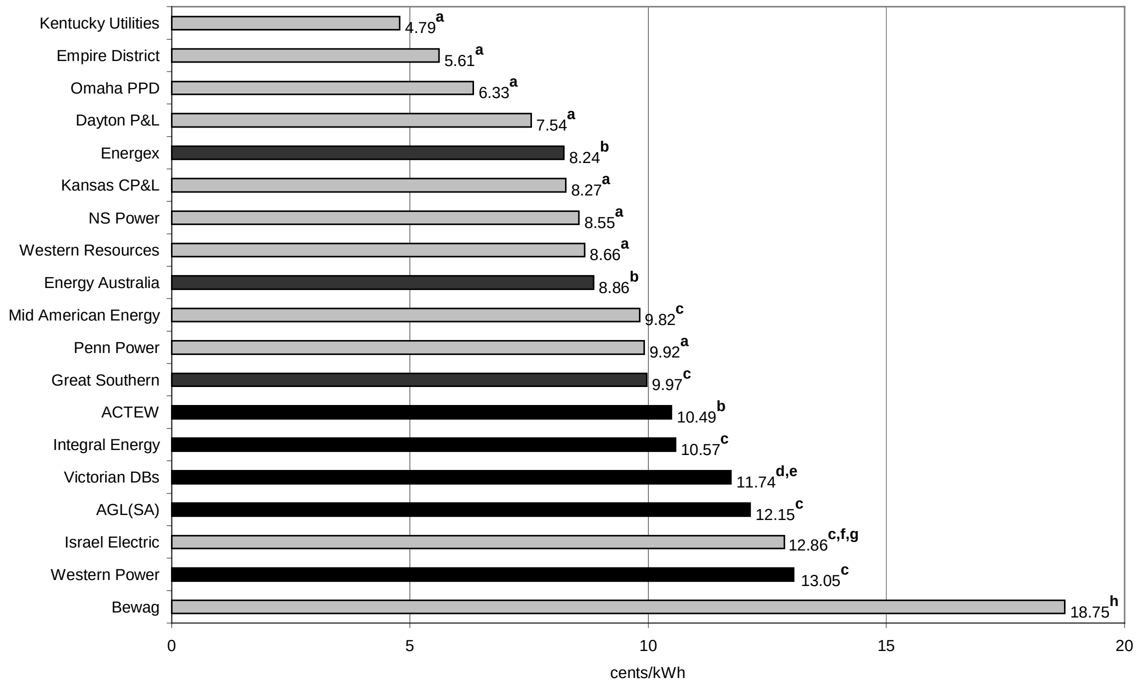
Note MB1 has a peak demand of 100kW, a load factor of 30 per cent, a proportion of off-peak usage of 28.5 per cent and an annual consumption of 263MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** Block tariffs produced the lowest average price per kWh. **c** Time-of-use tariffs produced the lowest average price per kWh. **d** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **e** The Winter off-peak share of annual consumption is adjusted according to the number of hours in the winter period. **f** Exclusion of religious holidays from the price calculations may understate the winter off-peak share of annual consumption. Israeli religious holidays generally take place during the summer and shoulder seasons, and thus their inclusion may increase the winter off-peak share of annual consumption. **g** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **h** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used to represent all five DBs. **i** The lowest average price per kWh is calculated on Bewag's existing tariff schedule. However, individual customers may be able to negotiate lower prices.

Data source: PC estimates.

Consumption bundle MB2

The results of the price comparisons for MB2 are presented in figure 4.4. MB2 has a higher load factor than MB1, even though peak demand remains the same. This change results in annual consumption increasing to 526MWh and off-peak usage increasing to 46.5 per cent (see table 4.1).

Figure 4.4 **Unadjusted average price index for MB2, Australian dollars, October 2000**



Note MB2 has a peak demand of 100kW, a load factor of 60 per cent, a percentage of off-peak consumption equal to 46.5 per cent and an annual consumption of 526MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **c** Time-of-use tariffs produced the lowest average price per kWh. **d** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used to represent all five DBs. **f** The Winter off-peak share of annual consumption is adjusted according to the number of hours in the winter period. **g** Exclusion of religious holidays from the price calculations may understate the winter off-peak share of annual consumption. Israeli religious holidays generally take place during the summer and shoulder seasons, and thus their inclusion may increase the winter off-peak share of annual consumption. **h** The lowest average price per kWh is calculated on Bewag's existing tariff schedule. However, individual customers may be able to negotiate lower prices.

Data source: PC estimates.

Compared with MB1, the average price per kWh for MB2 declines for all of the utilities. The reasons for this include:

- the increase in load factor, leading to a greater proportion of cheaper off-peak electricity; and
- fixed costs are spread over a higher level of consumption which reduces the per-unit cost of electricity.

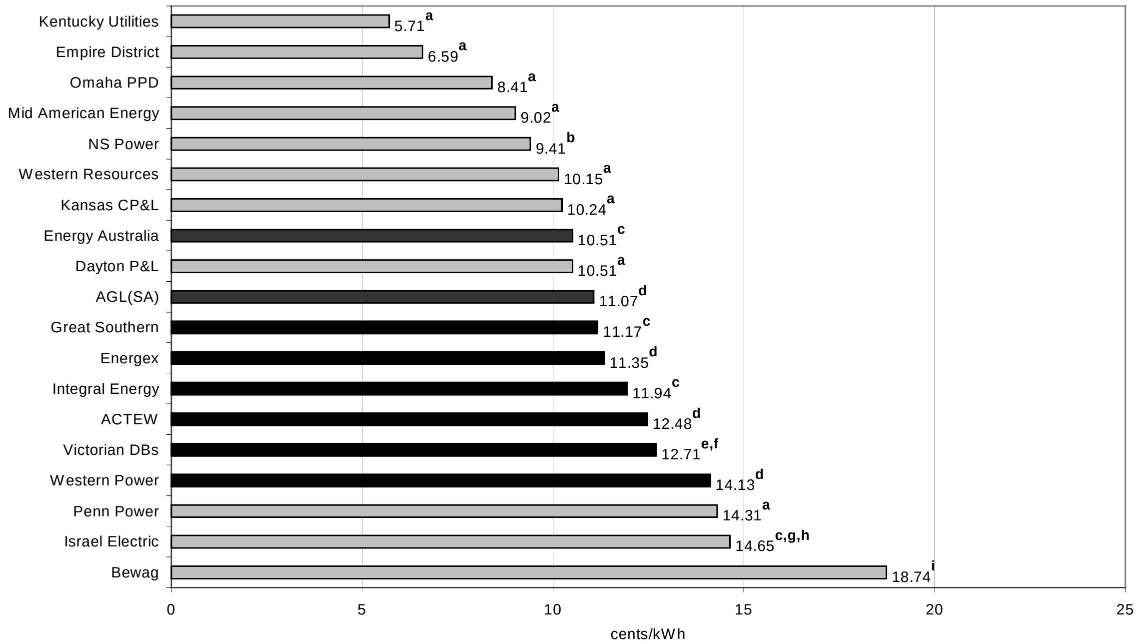
For some utilities, the cheapest tariff is one that incorporates both supply costs and a demand charge. Relative to MB1, these costs are spread over a higher level of annual consumption, leading to a significant reduction in the cost of electricity.

For other utilities, particularly some of the North American utilities, prices do not fall as much. This is often because the lowest tariff for these utilities is primarily consumption related, making fixed supply costs and demand charges less important in determining the average cost of electricity.

Consumption bundle MB3

There were only minor changes in the relative rankings of the utilities between MB3 and MB1 (see figures 4.5 and 4.3). Again, the main reason for this is that the load factor and the percentage of off-peak consumption remained unchanged, even though peak demand and annual consumption increased between the two bundles.

Figure 4.5 **Unadjusted average price index for MB3, Australian dollars, October 2000**



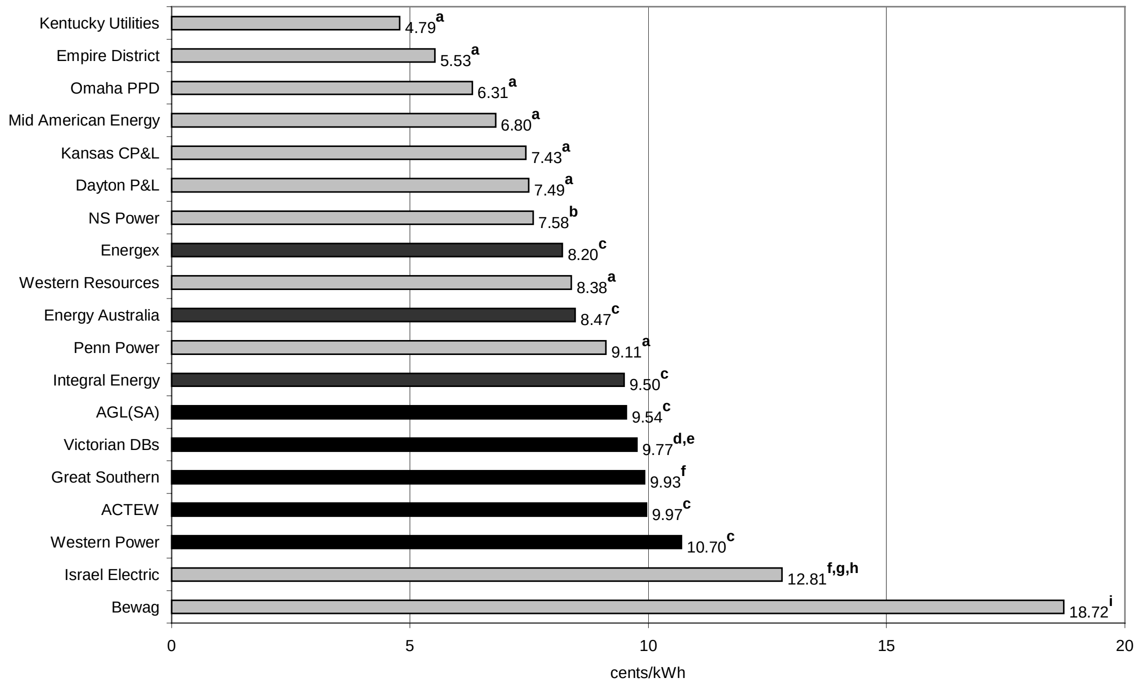
Note MB3 has a peak demand of 250kW, a load factor of 30 per cent, a percentage of off-peak consumption of 28.5 per cent and an annual consumption of 657MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge. **c** Time-of-use tariffs produced the lowest average price per kWh. **d** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **e** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used to represent all five DBs. **g** The Winter off-peak share of annual consumption is adjusted according to the number of hours in the winter period. **h** Exclusion of religious holidays from the price calculations may understate the winter off-peak share of annual consumption. Israeli religious holidays generally take place during the summer and shoulder seasons, and thus their inclusion may increase the winter off-peak share of annual consumption. **i** The lowest average price per kWh is calculated on Bewag's existing tariff schedule. However, individual customers may be able to negotiate lower prices.

Data source: PC estimates.

Consumption bundle MB4

The results of the price comparisons for MB4 are presented in figure 4.6. MB4 differs from MB3 in that the load factor is increased to 60 per cent, whilst the peak demand remains unchanged. This has the effect of increasing off-peak usage and increasing annual consumption from 657MWh to 1314MWh.

Figure 4.6 **Unadjusted average price index for MB4, Australian dollars, October 2000**



Note MB4 has a peak demand of 250kW, a load factor of 60 per cent, a percentage of off-peak consumption of 46.5 per cent and an annual consumption of 1314MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge. **c** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **d** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used to represent all five DBs. **f** Time-of-use tariffs produced the lowest average price per kWh. **g** The Winter off-peak share of annual consumption is adjusted according to the number of hours in the winter period. **h** Exclusion of religious holidays from the price calculations may understate the winter off-peak share of annual consumption. Israeli religious holidays generally take place during the summer and shoulder seasons, and thus their inclusion may increase the winter off-peak share of annual consumption. **i** The lowest average price per kWh is calculated on Bewag's existing tariff schedule. However, individual customers may be able to negotiate lower prices.

Data source: PC estimates.

Of the six small to medium business bundles, MB4 generated the lowest average prices per kWh. Spreading fixed costs over a higher level of annual consumption is the main reason for this occurring.

4.3 Sensitivity analysis

The price comparisons presented in section 4.2 rely upon certain assumptions. These assumptions relate to the level of annual consumption, peak demand and load factor, as well as the percentage of off-peak usage. Another assumption made is the use of PPPs to convert local average prices to Australian dollars.

The sensitivity analysis of assumptions on the results for small to medium businesses is more complex than it is for residential customers. Isolating the impact of changing only one assumption is difficult because of the inter-relationship between annual consumption, peak demand and load factor (see section 4.1). Changing the value of one of these factors affects the value of either one or both of the other factors.

To some extent, the range of parameters chosen to define the consumption bundles provide for an examination of the sensitivity of prices to their value. For example, peak demand varies between 11kW and 250kW, whilst annual consumption varies between 60MWh and 1314MWh. Indeed, the consumption bundles were chosen to exhibit such a range of values so that they might fully cover the breadth of amounts and consumption patterns by small to medium businesses.

Impact of changing the level of peak demand and annual consumption

SB1, MB2 and MB4 provide a useful comparison of the effect of changing peak demand and annual consumption while holding the load factor and the percentage of off-peak usage constant. The three bundles differ from one another in that peak demand and, as a consequence, annual consumption increases from SB1 to MB4.

Increasing peak demand and annual consumption, while holding load factor and the percentage of off-peak usage constant, did not produce a large change in the relative rankings of the Australian utilities (see table 4.3, the Australian utilities are bolded).

However, there was some movement in the rankings which appears most significant between SB1 and MB2. This may be due to the higher level of annual consumption included in MB2 compared with SB1. With higher annual consumption, access charges are spread over a higher level of consumption, which affect the rankings because utilities give different weights to access and usage charges in their tariff schedules.

Table 4.3 **Relative rankings of the utilities, SB1, MB2 and MB4**

Utility	*SB1*	*MB2*	*MB4*
Kentucky Utilities	1	1	1
Omaha PPD	2	3	3
Dayton P&L	3	4	6
Empire District	4	2	2
NS Power	5	7	7
Penn Power	6	11	11
Kansas CP&L	7	6	5
Western Resources	8	8	9
Mid American Energy	9	10	4
Great Southern	**10**	**12**	**15**
Integral Energy	**11**	**14**	**12**
Energy Australia	**12**	**9**	**10**
Energex	**13**	**5**	**8**
ACTEW	**14**	**13**	**16**
AGL(SA)	**15**	**16**	**13**
Victorian DBs	**16**	**15**	**14**
Western Power	**17**	**18**	**17**
Israel Electric	18	17	18
Bewag	19	19	19

Source: PC estimates.

Impact of changing the load factor

Isolating the impact of changing the load factor is complicated by the corresponding change in the level of off-peak usage and annual consumption. This affects prices because:

- off-peak usage usually incurs lower usage charges; and
- changing the level of annual consumption affects the per-unit cost of access charges.

The relative weights that utilities give to access charges in their tariffs, or the structure of peak versus off-peak tariff rates, affects price relativities. However, changing the load factor does not have a large effect on the relative rankings of the Australian utilities (see comparison of prices for MB1 and MB2 in table 4.4).

Table 4.4 **Relative rankings of the utilities, MB1 and MB2**

Utility	*MB1*	*MB2*
Kentucky Utilities	1	1
Empire District	2	2
Omaha PPD	3	3
Western Resources	4	8
NS Power	5	7
Dayton P&L	6	4
Mid American Energy	7	10
Energy Australia	**8**	**9**
Kansas CP&L	9	6
Great Southern	**10**	**12**
Energex	**11**	**5**
Integral Energy	**12**	**14**
ACTEW	**13**	**13**
AGL(SA)	**14**	**16**
Israel Electric	15	17
Victorian DBs	**16**	**15**
Western Power	**17**	**18**
Penn Power	18	11
Bewag	19	19

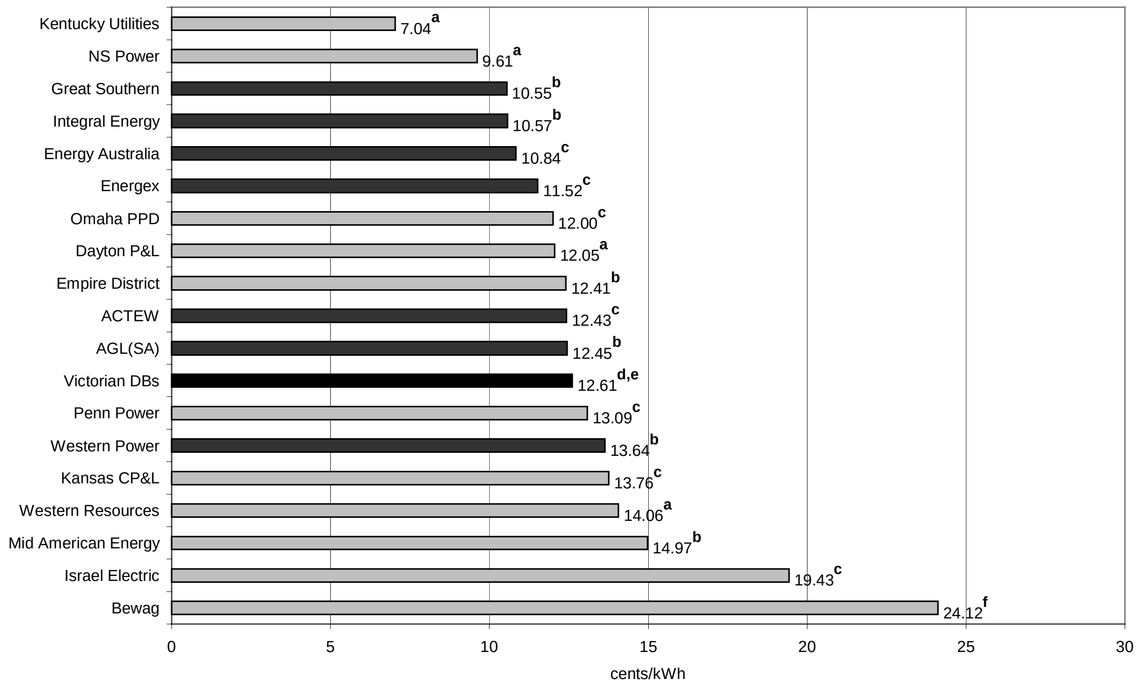
Source: PC estimates.

Impact of changing the basis for the currency conversion

The price comparisons were made on a currency conversion method based upon PPP rates. The price comparisons were recalculated using market exchange rates as the basis of conversion. The market exchange rates used are listed in table 3.4.

The effect of using market exchange rates was to improve the relative ranking of the Australian utilities because of the relatively low value of the Australian dollar in October 2000 (see figures 4.7 to 4.12). However, as noted in chapter 3, the use of market exchange rates for currency conversion is inconsistent with the objectives of the study — to determine whether Australian customers pay more for electricity relative to other goods and services than their overseas counterparts.

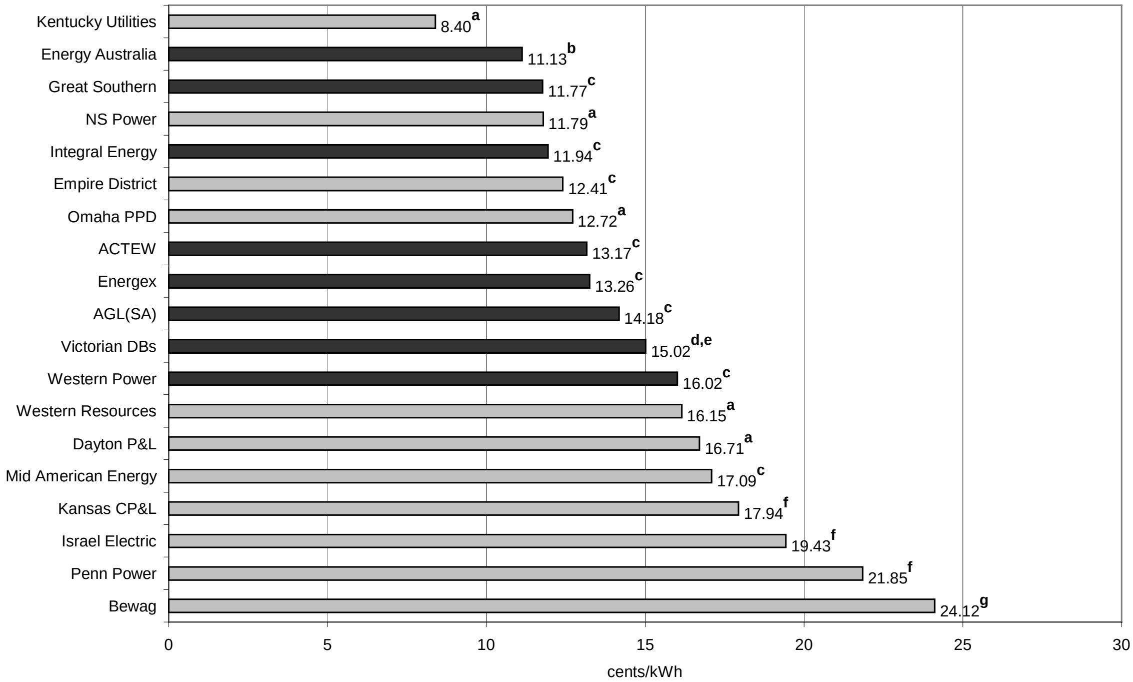
Figure 4.7 **Impact of using market exchange rates for SB1, Australian dollars, October 2000**



Note SB1 has a peak demand of 11kW, a load factor of 60 per cent, a percentage of off-peak consumption of 46.5 per cent and an annual consumption of 60MWh. Prices are converted to A$ using market exchange rates applicable at 31 October 2000. All prices include federal, State and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** Time-of-use tariffs produced the lowest average price per kWh. **c** Block tariffs produced the lowest average price per kWh. **d** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used to represent all five DBs. **f** The lowest average price per kWh is calculated on Bewag's existing tariff schedule. However, individual customers may be able to negotiate lower prices.

Data source: PC estimates.

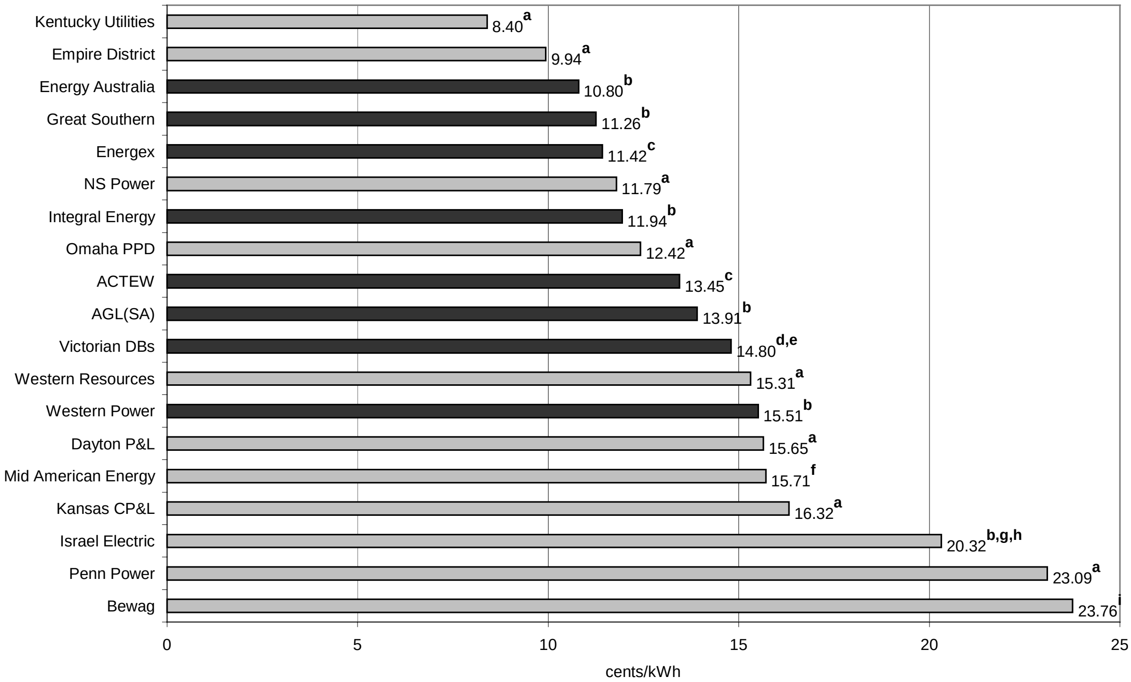
Figure 4.8 **Impact of using market exchange rates for SB2, Australian dollars, October 2000**



Note SB2 has a peak demand of 23kW, a load factor of 30 per cent, a percentage of off-peak consumption of 28.5 per cent and annual consumption of 60MWh. Prices are converted to A$ using market exchange rates applicable at 31 October 2000 All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **c** Time-of-use tariffs produced the lowest average price per kWh. **d** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used to represent all five DBs. **f** Block tariffs produced the lowest average price per kWh. **g** The lowest average price per kWh is calculated on Bewag's existing tariff schedule. However, individual customers may be able to negotiate lower prices.

Data source: PC estimates.

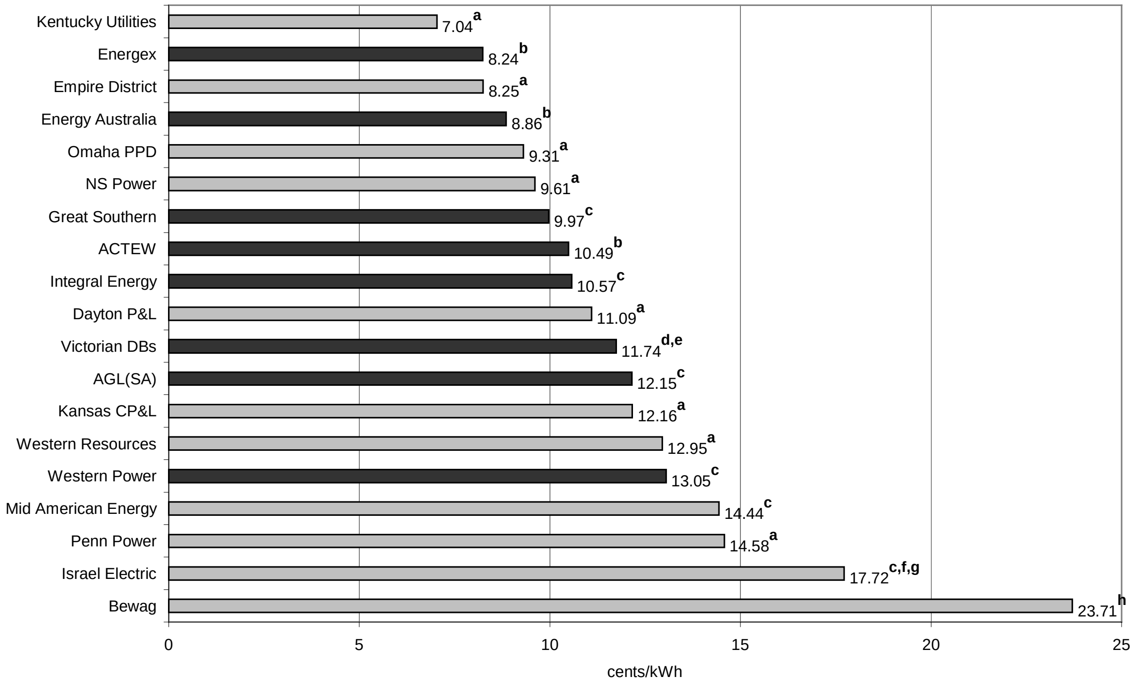
Figure 4.9 **Impact of using market exchange rates for MB1, Australian dollars, October 2000**



Note MB1 has a peak demand of 100kW, a load factor of 30 per cent, a proportion of off-peak usage of 28.5 per cent and annual consumption of 263MWh. Prices are converted to A$ using market exchange rates applicable at 31 October 2000. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** Time-of-use tariffs produced the lowest average price per kWh. **c** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **d** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used to represent all five DBs. **f** Block tariffs produced the lowest average price per kWh. **g** The Winter off-peak share of annual consumption is adjusted according to the number of hours in the winter period. **h** Exclusion of religious holidays from the price calculations may understate the winter off-peak share of annual consumption. Israeli religious holidays generally take place during the summer and shoulder seasons, and thus their inclusion may increase the winter off-peak share of annual consumption. **i** The lowest average price per kWh is calculated on Bewag's existing tariff schedule. However, individual customers may be able to negotiate lower prices.

Data source: PC estimates.

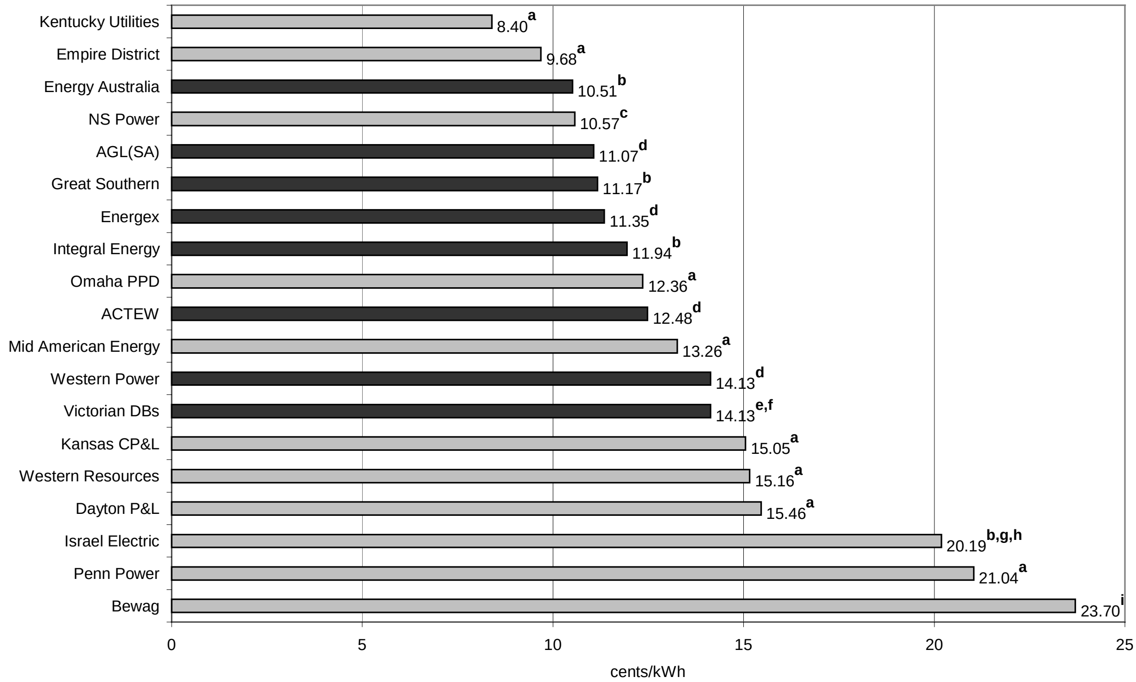
Figure 4.10 **Impact of using market exchange rates for MB2, Australian dollars, October 2000**



Note MB2 has a peak demand of 100kW, a load factor of 60 per cent, a percentage of off-peak consumption of 46.5 per cent and an annual consumption of 526MWh. Prices are converted to A$ using market exchange rates applicable at 31 October 2000. All prices include federal, State and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **c** Time-of-use tariffs produced the lowest average price per kWh. **d** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used to represent all five DBs. **f** The Winter off-peak share of annual consumption is adjusted according to the number of hours in the winter period. **g** Exclusion of religious holidays from the price calculations may understate the winter off-peak share of annual consumption. Israeli religious holidays generally take place during the summer and shoulder seasons, and thus their inclusion may increase the winter off-peak share of annual consumption. **h** The lowest average price per kWh is calculated on Bewag's existing tariff schedule. However, individual customers may be able to negotiate lower prices.

Data source: PC estimates.

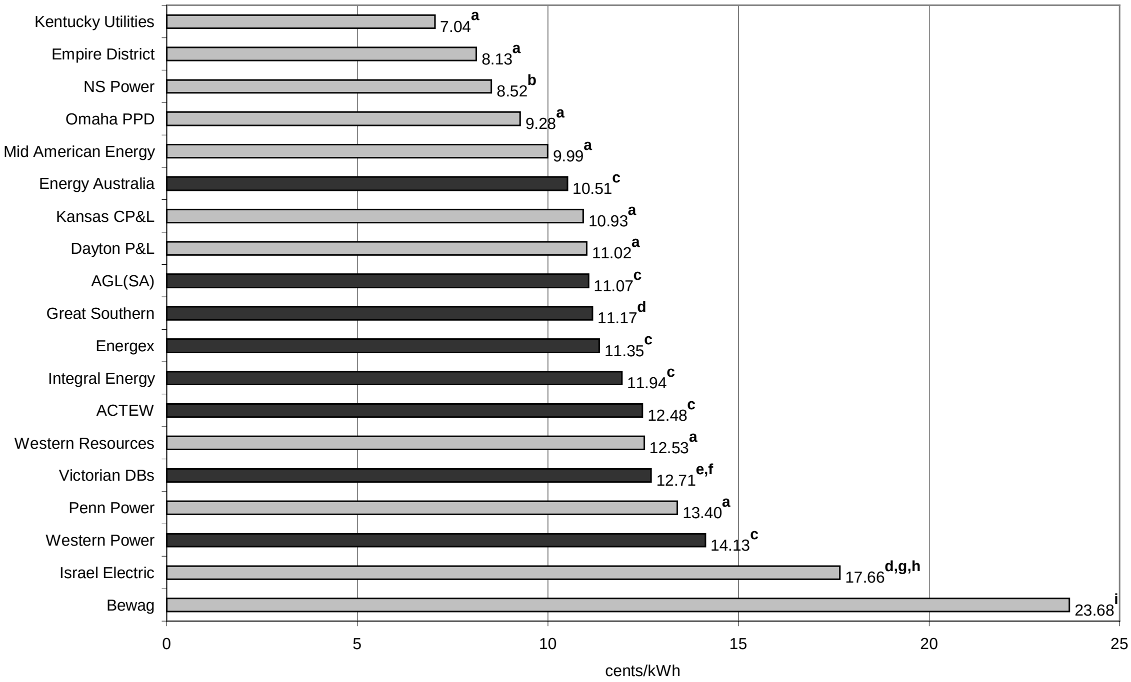
Figure 4.11 Impact of using market exchange rates for MB3, Australian dollars, October 2000



Note MB3 has a peak demand of 250kW, a load factor of 30 per cent, a percentage of off-peak consumption of 28.5 per cent and annual consumption of 657MWh. Prices are converted to A$ using market exchange rates applicable at 31 October 2000. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** Time-of-use tariffs produced the lowest average price per kWh. **c** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge. **d** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **e** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used to represent all five DBs. **g** The Winter off-peak share of annual consumption is adjusted according to the number of hours in the winter period. **h** Exclusion of religious holidays from the price calculations may understate the winter off-peak share of annual consumption. Israeli religious holidays generally take place during the summer and shoulder seasons, and thus their inclusion may increase the winter off-peak share of annual consumption. **i** The lowest average price per kWh is calculated on Bewag's existing tariff schedule. However, individual customers may be able to negotiate lower prices.

Data source: PC estimates.

Figure 4.12 **Impact of using market exchange rates for MB4, Australian dollars, October 2000**



Note MB4 has a peak demand of 250kW, a load factor of 60 per cent, a percentage of off-peak consumption of 46.5 per cent and an annual consumption of 1314MWh. Prices are converted to A$ using market exchange rates applicable at 31 October 2000. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge. **c** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **d** Time-of-use tariffs produced the lowest average price per kWh. **e** Prices for the Victorian DBs were calculated using tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh was used to represent all five DBs. **g** The Winter off-peak share of annual consumption is adjusted according to the number of hours in the winter period. **h** Exclusion of religious holidays from the price calculations may understate the winter off-peak share of annual consumption. Israeli religious holidays generally take place during the summer and shoulder seasons, and thus their inclusion may increase the winter off-peak share of annual consumption. **i** The lowest average price per kWh is calculated on Bewag's existing tariff schedule. However, individual customers may be able to negotiate lower prices.

Data source: PC estimates.

Impact of revised Victorian tariff schedule

On 1 January 2001, a new tariff schedule was introduced for the Victorian Distributors. Table 4.5 indicates that the unit prices introduced under this revised schedule did not have a large impact on their relative rankings.

Table 4.5 **Unadjusted average price index for revised Victorian tariffs for SB1 to MB4, Australian dollars, October 2000 and January 2001**

Consumption bundle	*Unrevised unadjusted prices October 2000*	*Revised unadjusted prices January 2001*
	cents/kWh	cents/kWh
SB1	12.61	12.78
SB2	15.02	15.21
MB1	14.80	14.99
MB2	11.74	11.90
MB3	12.71	12.88
MB4	9.77	9.90

Note Prices include federal, state and/or local taxes where applicable. Prices for Victorian DBs were calculated using tariffs rates applicable at January 2001. In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; AGL (Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. Powercor's average price per kWh is used to represent all five DBs.

Source: PC estimates.

4.4 In summary

Price comparisons of the kind presented in this chapter are inevitably based on assumptions. Although these introduce an element of subjectivity into the price comparisons, there is nevertheless a reasonable basis for making the following broad conclusions:

- There was a wide dispersion in the relative prices of the utilities studied.
- As the size of annual consumption increases, overseas utilities tend to improve their rankings. The reason for this is the use of block tariffs, whereby customers pay progressively lower unit prices as consumption increases.

That said, these conclusions are based on price comparisons that are unadjusted for cost factors outside the control of the industry in the short-run.

The comparisons drawn are not greatly affected by changes in assumptions about the consumption bundles or load factor used. However, the relatively low value of Australia's dollar at October 2000 improved the ranking of Australian utilities relative to those overseas, if the price comparisons are based on market exchange rates.

5 Unadjusted large business prices

In this chapter, Australian and overseas electricity prices are compared for typical patterns of electricity usage by large businesses.

In Australia, most businesses that purchase more than 160MWh annually are eligible to enter the National Electricity Market (NEM).[1] These customers, termed ‘contestable’ or ‘non-franchise’, are able to negotiate an electricity supply contract with a retailer of their choice.[2]

As the electricity bundles specified in this chapter comprise annual consumption well in excess of 160MWh, it was assumed that Australian businesses that purchase the bundles of electricity specified in this chapter would choose to operate in the NEM.

In contrast to the situation for customers who consume less than 160MWh annually, the price of electricity for large customers in Australia is determined by negotiation and is therefore not publicly available in tariff schedules. Consequently, spot market based estimates of contract charges were used instead of the tariff schedules used for calculating average residential and small to medium business prices. For a discussion on financial instruments, such as contracts, and their interaction with spot market prices see chapter 2.

For overseas electricity customers, most electricity distributors operate in a non-contestable market, with large customers purchasing their electricity at rates contained in publicly-available tariff schedules. For these utilities, publicly-available tariff schedules applicable to business customers were used.

The electricity price comparisons reported in this chapter were not adjusted for the effect of costs outside the control of suppliers. Information on these cost factors and their influence on costs, and hence prices, are examined in chapter 7.

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[1] The threshold of 160MWh applies to businesses in New South Wales, Victoria and the Australian Capital Territory as at October 2000. The thresholds in Queensland, South Australia and Western Australia are 200MWh, 750MWh and 8760MWh respectively.

[2] Alternatively, contestable customers can purchase their electricity directly from the wholesale market.

5.1 Methodology

The average price in cents per kilowatt hour (cents/kWh) for the supply of electricity for one year was calculated for typical levels of electricity usage for large businesses in Australia and overseas. Tariff schedules applying in October 2000 were used.

Information on the assumptions underlying the calculation of the electricity prices was presented in chapter 3. Where different assumptions were required in this chapter, they are noted.

Large business electricity bundles

Six consumption bundles were developed to cover the electricity usage of large businesses (see table 5.1). These electricity bundles are a subset of those used by the Electricity Supply Association of Australia (ESAA) (ESAA 2000a).

Table 5.1 **Large business consumption bundles**

Bundle name	*Peak demand*	*Load factor*	*Consumption in off-peak periods*[a]	*Annual consumption*
	kW	per cent	per cent	MWh
LB1	500	30	28.5	1314
LB2	500	60	46.5	2628
LB3	1000	30	28.5	2628
LB4	1000	60	46.5	5256
LB5	2500	30	37.6	6570
LB6	2500	60	46.9	13 140

[a] These are the off-peak percentages used by the ESAA. Where a utility offers off-peak rates for a different number of hours to that assumed by the ESAA, these percentages are adjusted accordingly.

Source: ESAA (2000a).

The main determinant of large electricity user prices is peak demand, rather than annual consumption. As such, the selected consumption bundles are based upon levels of peak demand. Various levels of load factors are then chosen to reflect the intensity of electricity usage. Changing the load factor for a given peak demand has the effect of increasing total annual consumption (see chapter 4 for a discussion of the relationships between the characteristics of the electricity bundles).

Following the methodology used by the ESAA (2000a), the proportion of electricity consumed in off-peak periods was determined according to table 5.2.

Table 5.2 **Proportion of off-peak consumption for selected load factors**

Level of demand	*30% load factor*	*60% load factor*
	per cent	per cent
Up to 1000kW	28.5	46.5
2500kW and above	37.6	46.9

Note These percentages assume the duration of the off-peak period is 98 hours per week. The percentages are adjusted accordingly where the tariff of an electricity supplier applies for a different number of hours.

Source: ESAA (2000a).

Australian prices

The invoice received by contestable customers from their electricity supplier separates the cost of electricity into its non-contestable (network charges) and contestable (energy charges) components. The methodology used mirrors this to identify the overall charge that minimises the cost of each bundle.

The tariff schedules of the electricity companies were used to calculate the network charge whereas the energy component of the electricity bill was estimated. Network and energy charges are defined in box 5.1.

Box 5.1 **Network and energy charges**

Network charges are the charges for the provision and use of the transmission and distribution networks. Network charges comprise two components — Transmission Use of System (TUOS) and Distribution Use of System (DUOS) charges.

The TUOS charge is a payment to the owner of the transmission network for provision of electricity from the generator to the point where the transmission network meets the distribution network. The TUOS charge is regulated by the Australian Competition and Consumer Commission.

The DUOS charge is a payment for providing electricity from the point where the transmission network and the distribution network meet to the customer. The payment is made to the owner of the distribution network. The DUOS charge is regulated by State and Territory governments.

Energy charges are the 'contestable' component of the electricity bill and reflect the cost of energy produced by generators. These charges also include a provision for transmission and distribution losses, wholesale market operation costs and a retail margin.

Calculating the contract charge for Australian businesses

Energy charges reflect the cost of energy produced by generators. The energy charge calculated comprises the following components:

- The 12 month average pool price of electricity for each State;
- A retail margin;
- National Electricity Market Management Company Limited (NEMMCO) fees; and
- Distribution Loss Factors (DLFs).

The 12 months selected was the period up to 1 April 2001. This period was chosen because October 2000, the reference date used in this report, lies in the middle of the period. As such, the average pool price used in the tariff calculations incorporates pool price data for the six months preceding *and* the six months following October 2000. This recognises that contracts are being negotiated through out any year and reflect expectations of future spot market prices.

The 12 month average pool price at any point in time is the weighted average pool price over the preceding 12 months. Data used to construct the State 12 month average pool price was obtained from NEMMCO weekly average spot prices and demand by State (NEMMCO 2001c).

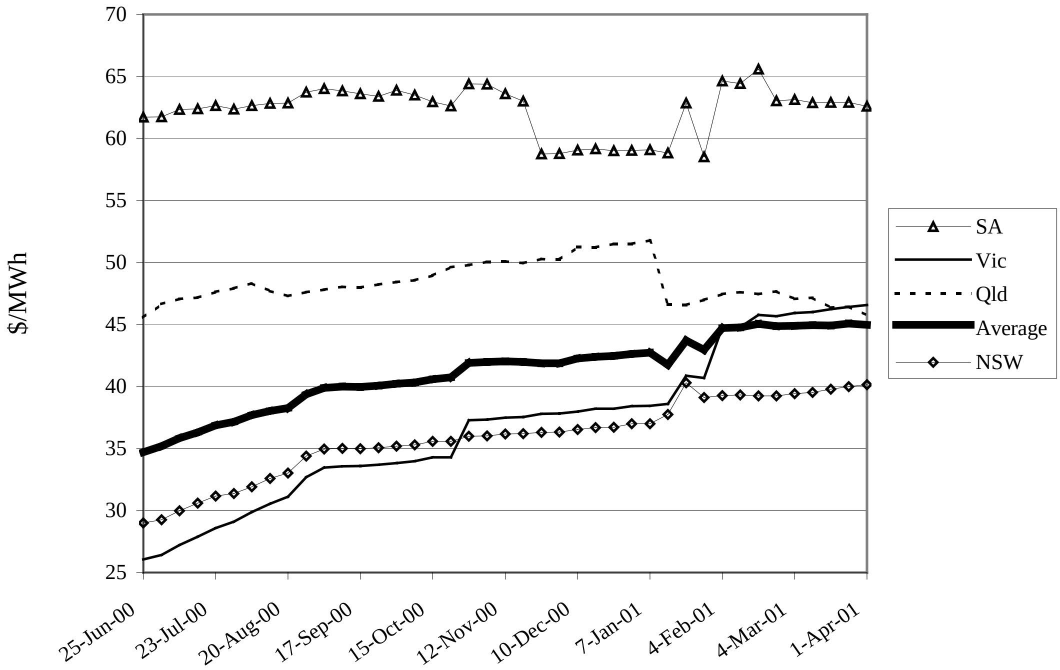
Prices for Western Power were not included in the price indexes as, at October 2000, Western Power did not operate in the NEM.

The behaviour of the 12 month average pool price between 25 June 2000 and 1 April 2001 differs markedly by State (see figure 5.1).

The average pool price in South Australia for the previous 12 months has fluctuated but remains at around the same level ($63/MWh) in April 2001, as it was in June 2000. Likewise, the 12 month average pool price in Queensland remains at around the same level as 18 months ago at $46/MWh.

By contrast, 12 month average pool prices have risen markedly in both New South Wales and Victoria. In New South Wales, the price has increased by about 38 per cent, or $10/MWh. The largest rise, however, has occurred in Victoria, where the 12 month average pool price has increased from $26 to $47/MWh, a rise of nearly 80 per cent. Indeed, since 25 June 2000, Victoria has moved from having the cheapest 12 month average pool price in Australia to being second behind only South Australia.

Figure 5.1 **12 month average electricity pool price by State[a,b]**



[a] These prices exclude Goods and Service Tax. [b] National average price excludes data from the Snowy Hydroelectric Scheme.

Data source: NEMMCO (2001c).

The weighted average pool price of electricity in Australia over the 12 months ending 1 April 2001 was $45/MWh, a rise of about $10/MWh over the comparable price at 25 June 2000.

It should be noted that spot market based estimates of contract charges are an indication of contract prices and some customers could face negotiated prices that differ from those reported. For example, the prices paid by some customers may have been determined earlier and do not reflect contemporary pool prices.

Consequently, the prices are indicative of the prices paid by customers who entered into contracts around October 2000.

DLFs are used to convert the customer's actual metered energy into the equivalent energy passing through the distribution network connection point by allowing for the distribution network losses that the customer's energy use causes between their meter and the transmission network connection point. As such, DLFs differ by distribution network, and hence by electricity distributor.

The four components listed above were used to calculate the energy charge (cents/kWh) as follows:

*Energy charge = (1 + Retail margin) * average pool price * DLF + NEMMCO fees*

where:

- The retail margin that covers administration costs and a premium for price certainty was assumed to be 10 per cent;
- The 12 month average pool price (the average weekly pool price over the preceding 12 months) was that prevailing at 1 April 2001; and
- NEMMCO fees were 0.0387cents/kWh (ESAA 2000a).

A 10 per cent retail margin is consistent with established ESAA methodology. ESAA assumes a 5 per cent retail margin on the overall charge, including the network charge and the energy charge. As the energy charge faced by most customers represents roughly half of the overall charge, a 10 per cent retail margin on the energy charge is consistent with a 5 per cent retail margin on the overall charge assumed by the ESAA.

While the retail margins adopted by individual utilities may differ, changes of one or two percentage points are unlikely to have a noticeable impact upon either the price relativities or rankings of the utilities.

Overseas prices

Most overseas distributors operate in non-contestable markets. Large customers purchase electricity at rates contained in publicly-available tariff schedules.

The single overseas utility operating in a competitive market as at October 2000 — Pennsylvania Power (Penn Power) — provides a tariff schedule that includes the charges associated with transmission and distribution as well as a default energy charge for customers choosing to remain with Penn Power.

Choice of network tariff schedules

In Australia, network tariff schedules vary between electricity suppliers, reflecting the different cost structures of electricity distributors. Both Australian and overseas electricity distributors offer a choice of network tariff schedules for customers. The characteristics of the tariff schedules of electricity distributors are discussed in more detail in chapters 2 and 4.

As in chapters 3 and 4, the reported prices are those that minimise the cost to the customer of the specified bundle of electricity.

Taxes

Indirect taxes and any other government charges and environmental taxes which form part of tariff schedules were included in the price comparisons. The rationale for including taxes in business prices is discussed in chapter 4.

Currency conversion

Purchasing Power Parities (PPPs) were used to compare electricity prices for large businesses across countries. These PPPs were calculated using Australian dollars as a common unit of account. More detail on the PPP methodology was presented in chapter 3.

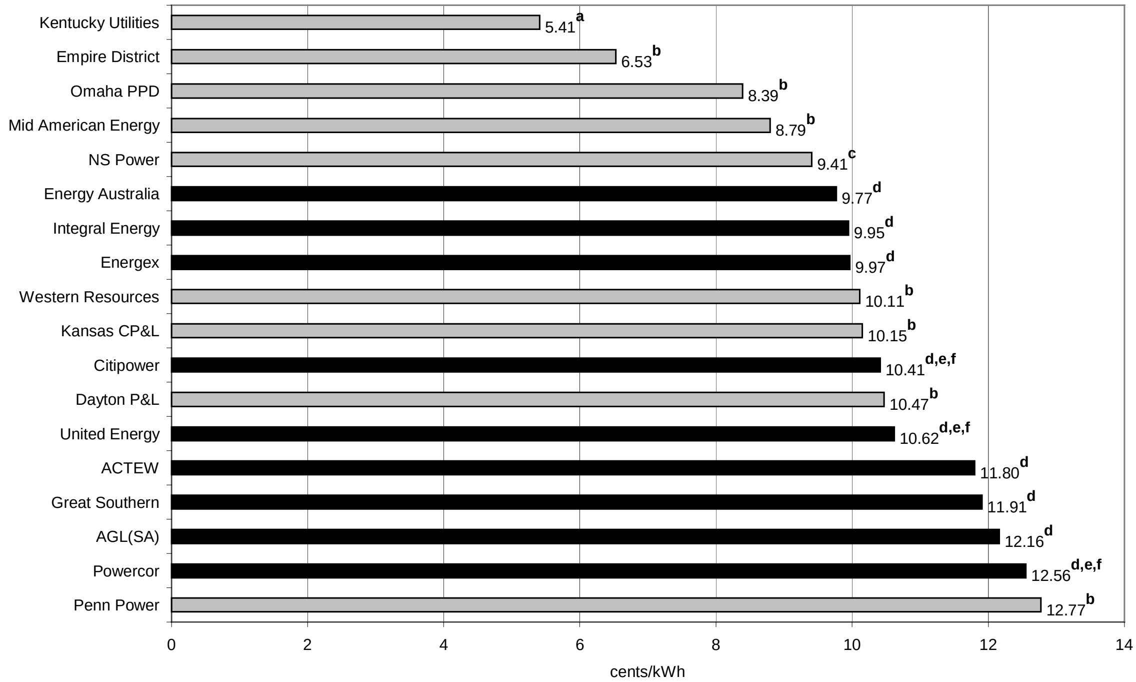
5.2 Prices

Relative prices were calculated for the six electricity bundles defined in table 5.1. As noted above, no adjustment was made for the effect of cost factors outside the control of the supplier.

Bundle LB1

Electricity consumption bundles LB1 and LB2 both comprise peak demand of 500kW with two levels of electricity consumption, 1314MWh and 2628MWh per annum. Electricity prices for LB1 are reported in Australian cents per kWh (see figure 5.2, the Australian utilities are shaded in black).

Figure 5.2 **Unadjusted average price index for LB1, Australian dollars, October 2000**



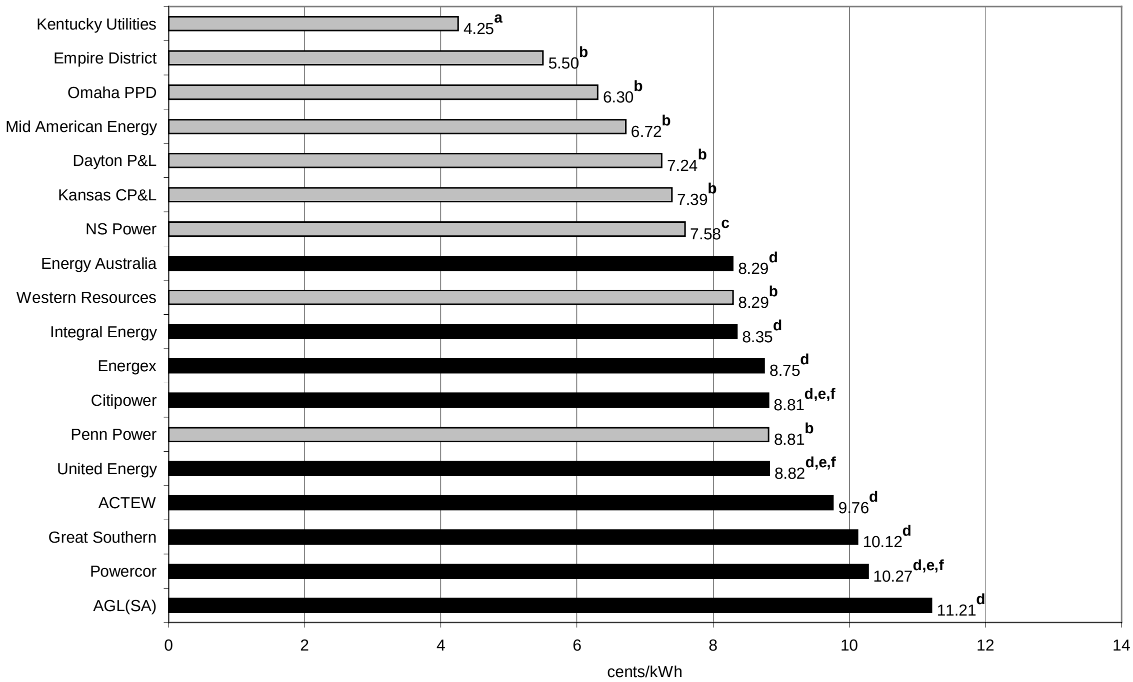
Note LB1 has a peak demand of 500kW, a load factor of 30 per cent, a consumption in off-peak periods of 28.5 per cent and an annual consumption of 1314MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Time-of-use tariffs produced the lowest average price per kWh. **b** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **c** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge. **d** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **e** The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent.

Data source: PC estimates.

Bundle LB2

For LB2, peak demand remains at 500kW whereas annual consumption is double that for LB1 at 2628MWh. Electricity prices for LB2 are reported in figure 5.3.

Figure 5.3 **Unadjusted average price index for LB2, Australian dollars, October 2000**



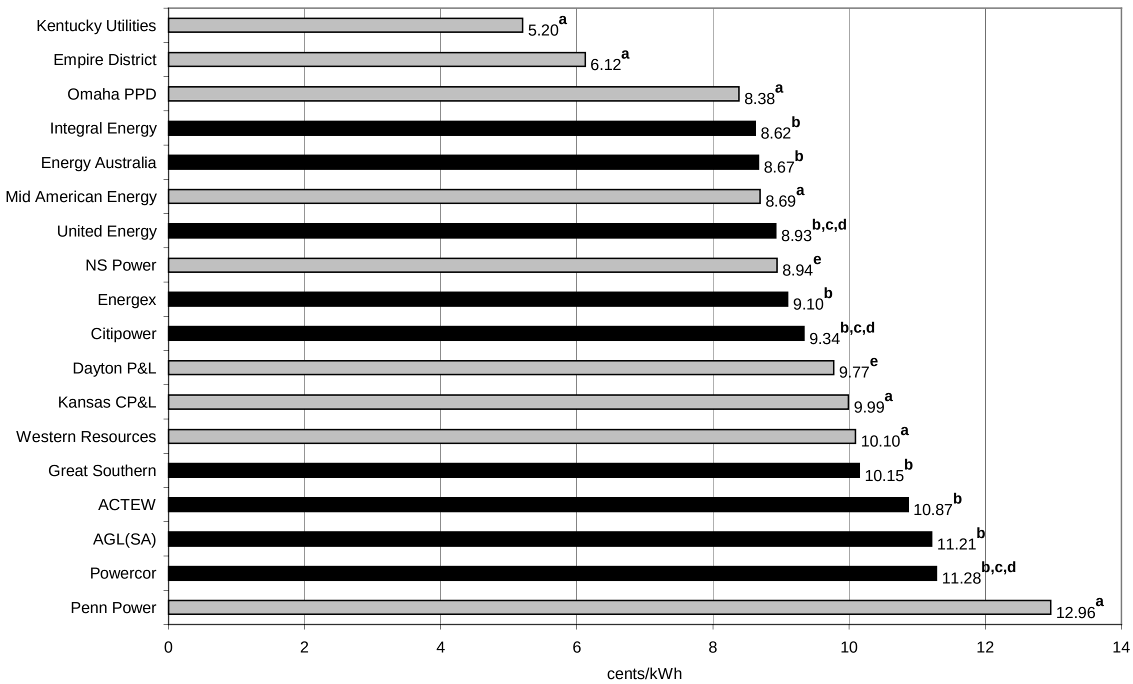
Note LB2 has a peak demand of 500kW, a load factor of 60 per cent, a consumption in off-peak periods of 46.5 per cent and an annual consumption of 2628MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Time-of-use tariffs produced the lowest average price per kWh. **b** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **c** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge. **d** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **e** The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent.

Data source: PC estimates.

Bundle LB3

Electricity consumption bundles LB3 and LB4 both comprise peak demand of 1000kW, with two levels of electricity consumption, 2628MWh and 5256MWh per annum. Electricity prices for LB3 are reported in figure 5.4.

Figure 5.4 **Unadjusted average price index for LB3, Australian dollars, October 2000**



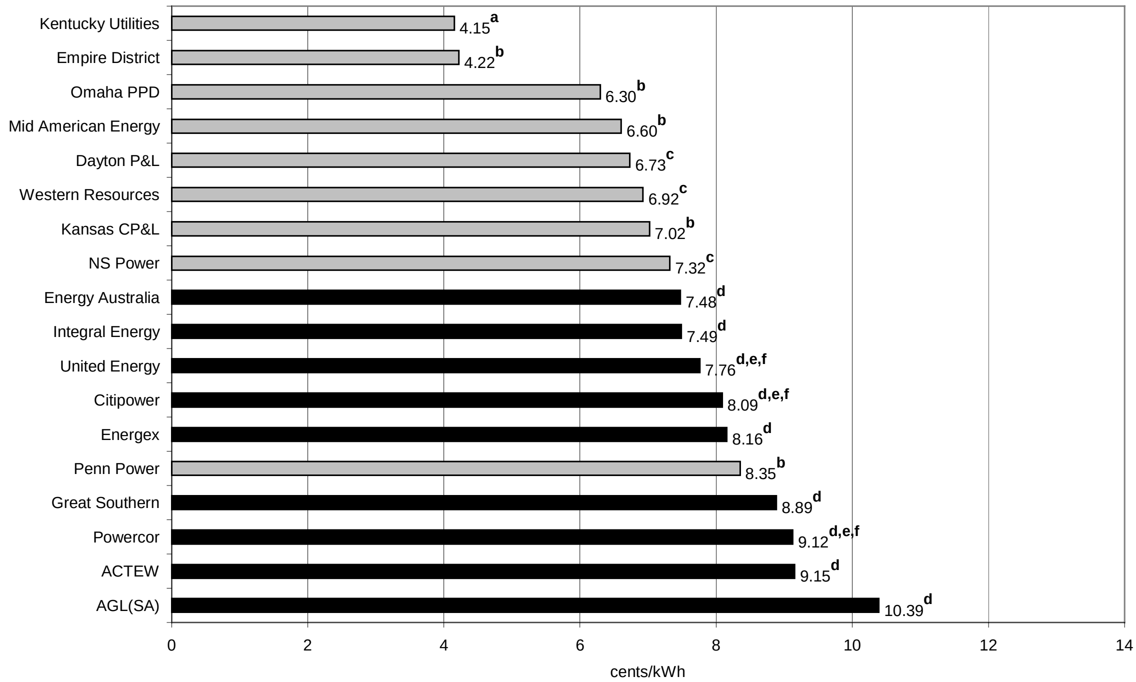
Note LB3 has a peak demand of 1000kW, a load factor of 30 per cent, a consumption in off-peak periods of 28.5 per cent and an annual consumption of 2628MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **c** The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **d** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. **e** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge.

Data source: PC estimates.

Bundle LB4

LB4 differs from LB3 in that although peak demand remains at 1000kW, annual consumption rises from 2628MWh to 5256MWh. Electricity prices for LB4 are reported in figure 5.5.

Figure 5.5 **Unadjusted average price index for LB4, Australian dollars, October 2000**



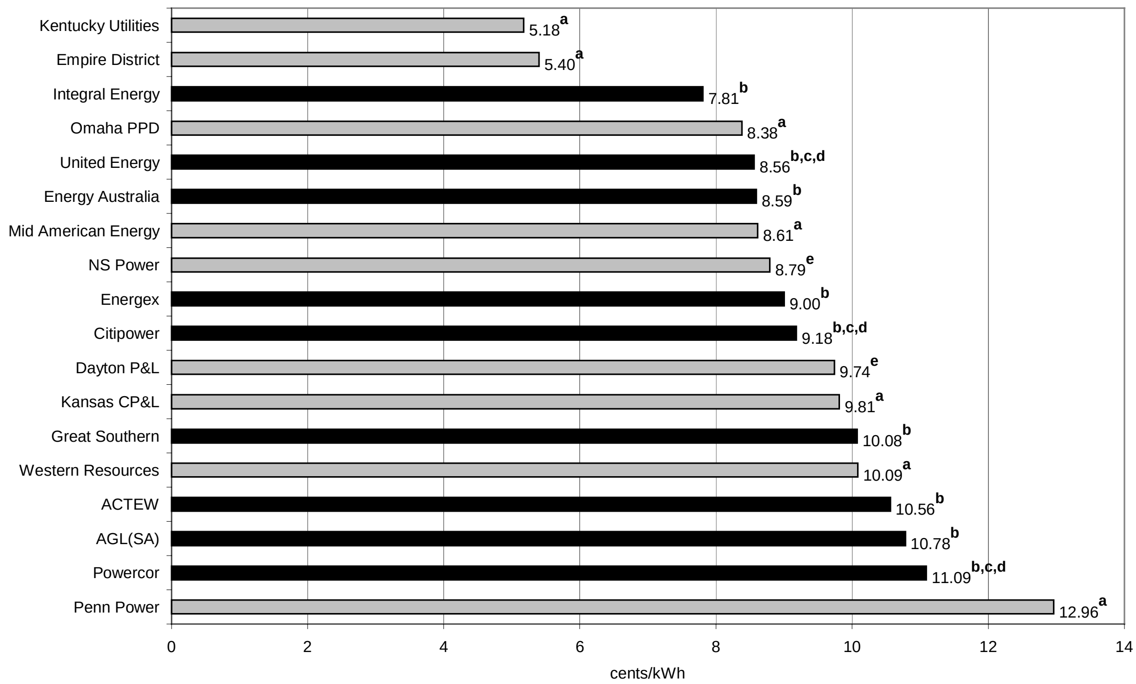
Note LB4 has a peak demand of 1000kW, a load factor of 60 per cent, a consumption in off-peak periods of 46.5 per cent and an annual consumption of 5256MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Time-of-use tariffs produced the lowest average price per kWh. **b** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **c** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge. **d** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **e** The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent.

Data source: PC estimates.

Bundle LB5

Electricity consumption bundles LB5 and LB6 both comprise peak demand of 2500kW, with two levels of electricity consumption, 6570MWh and 13 140MWh per annum. Electricity prices for LB5 are shown in figure 5.6.

Figure 5.6 **Unadjusted average price index for LB5, Australian dollars, October 2000**



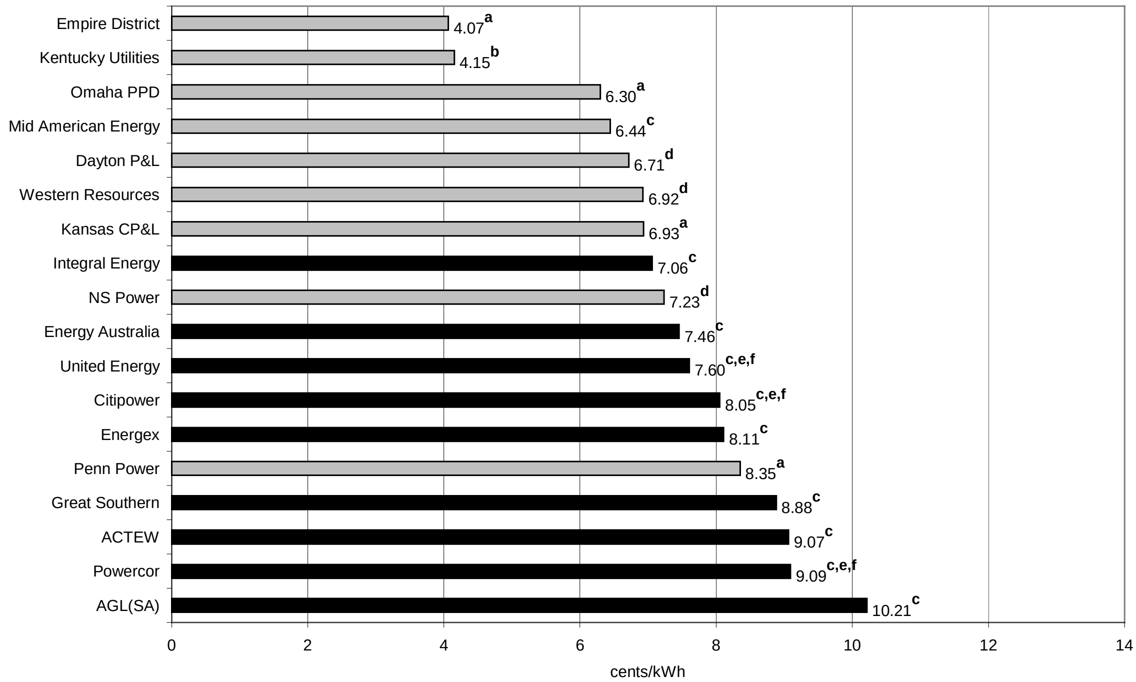
Note LB5 has a peak demand of 2500kW, a load factor of 30 per cent, a consumption in off-peak periods of 37.6 per cent and an annual consumption of 6570MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. [a] The lowest average price per kWh is based on a block tariff that incorporated a demand charge. [b] The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. [c] The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. [d] In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. [e] The lowest average price per kWh is based on a flat rate tariff combined with a demand charge.

Data source: PC estimates.

Bundle LB6

LB6 differs from LB4 in that although peak demand remains at 2500kW, the annual consumption doubles from 6570MWh to 13 140MWh. Electricity prices for LB6 are reported in figure 5.7.

Figure 5.7 Unadjusted average price index for LB6, Australian dollars, October 2000



Note LB6 has a peak demand of 2500kW, a load factor of 60 per cent, a consumption in off-peak periods of 46.9 per cent and an annual consumption of 13 140MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. [a] The lowest average price per kWh is based on a block tariff that incorporated a demand charge. [b] Time-of-use tariffs produced the lowest average price per kWh. [c] The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. [d] The lowest average price per kWh is based on a flat rate tariff combined with a demand charge. [e] The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. [f] In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent.

Data source: PC estimates.

5.3 Sensitivity analysis

Values of peak demand, load factor, percentage of off-peak usage and annual consumption of electricity are assumed for the price comparisons presented in the previous section. The values chosen for the consumption bundles exhibit a range of values for each defining characteristic (see table 5.1). For example, peak demand varies between 500kW and 2500kW and annual consumption increases by a factor of ten from 1314MWh to 13 140MWh.

The consumption bundles were chosen to exhibit a range of values to cover the consumption patterns of most large businesses. In this way, sensitivity analysis is already embodied to some extent in the differences between the bundles.

The sensitivity of relative prices were tested further as follows:

- Increasing peak demand to the subtransmission level, namely 10 000kW.
- Examining the effect of increasing annual consumption across bundles with the same peak demand.
- Increasing load factors to 80 per cent for the three levels of peak demand (500, 1000 and 2500kW).[3]
- Using market exchange rates rather than PPP exchange rates.

Increasing demand to subtransmission level

Price comparisons were conducted for very large electricity customers who consume electricity at the subtransmission level, namely at voltages in excess of 33 000 volts (see table 5.3).

Table 5.3 **Very large business consumption bundles**

Bundle name	*Peak demand*	*Load factor*	*Consumption in off-peak periods*	*Annual consumption*
	kW	per cent	per cent	MWh
VLB1	10 000	30	37.6	26 280
VLB2	10 000	60	46.9	52 560

Note These are the off-peak percentages used by the ESAA. Where a utility offers off-peak rates for a different number of hours to that assumed by the ESAA, these percentages are adjusted accordingly.

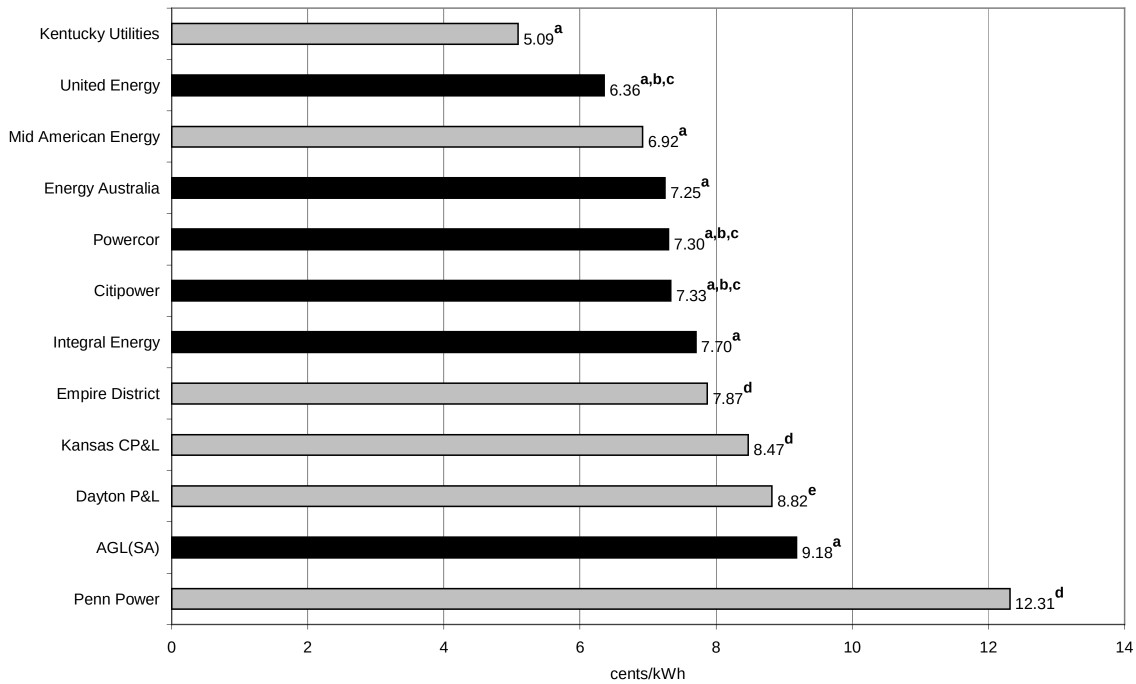
Source: ESAA (2000a).

[3] Only a fraction of businesses would consume electricity at a load factor in excess of 80 per cent.

Bundle VLB1

Electricity prices for VLB1 are reported in figure 5.8. Note that there are fewer utilities represented as some did not have a tariff schedule that matched the characteristics for electricity at the subtransmission level.

Figure 5.8 **Unadjusted average price index for VLB1, Australian dollars, October 2000**



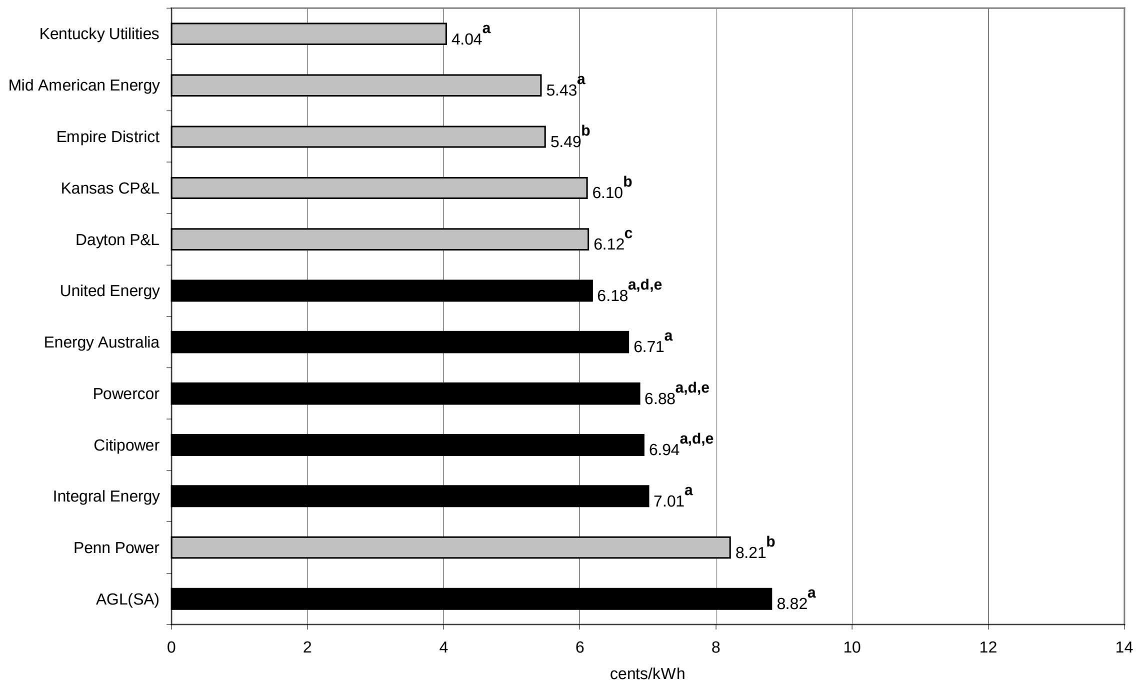
Note VLB1 has a peak demand of 10 000kW, a load factor of 30 per cent, a consumption in off-peak periods of 37.6 per cent and an annual consumption of 26 280MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **b** The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **c** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. **d** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **e** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge.

Data source: PC estimates.

Bundle VLB2

The prices for VLB2 (the same characteristics as VLB1 except the load factor has increased from 30 per cent to 60 per cent) indicate that the overseas utilities improved their performance relative to VLB1 (see figures 5.8 and 5.9).

Figure 5.9 **Unadjusted average price index for VLB2, Australian dollars, October 2000**



Note VLB2 has a peak demand of 10 000kW, a load factor of 60 per cent, a consumption in off-peak periods of 46.9 per cent and an annual consumption of 52 560MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **b** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **c** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge. **d** The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent.

Data source: PC estimates.

Overseas utilities continued to have prices that were lower at the 60 per cent load factor than at the 30 per cent load factor relative to Australian utility prices across all large business bundles examined in this chapter. Further, price relativities increase between bundles with the same peak demand — between LB2 and LB1, between LB4 and LB3, and between LB6 and LB5.

The chief reasons for this, as touched upon above, are the use of block energy rates which fall as consumption increases and high fixed costs (often in the form of demand charges), which fall as consumption increases (as peak demand remains constant).

Effect of increasing annual consumption

The sensitivity of price relativities to the level of annual consumption was examined by comparing across pairs of bundles with the same peak demand (see table 5.4).

Table 5.4 **Change in electricity prices with change in annual consumption levels**

Utility	*Percentage change in price*		
	LB1 and LB2	*LB3 and LB4*	*LB5 and LB6*
Penn Power	-31	-36	-36
Dayton P&L	-31	-31	-30
Kansas CP&L	-27	-30	-29
Omaha PPD	-25	-25	-25
Mid American Energy	-24	-24	-25
Kentucky Utilities	-21	-20	-20
NS Power	-19	-18	-18
Powercor	-18	-19	-18
Western Resources	-18	-31	-31
ACTEW	-17	-16	-14
United Energy	-17	-13	-11
Integral Energy	-16	-13	-12
Empire District	-16	-31	-25
Citipower	-15	-13	-12
Energy Australia	-15	-14	-13
Great Southern	-15	-12	-12
Energex	-12	-10	-10
AGL(SA)	-8	-7	-5

Data source: Figures 5.2 and 5.3.

The increases in annual consumption examined are:

- 1314 to 2628MWh across LB1 and LB2;
- 2628 to 5256MWh across LB3 and LB4; and
- 6570 to 13 140MWh across LB5 and LB6.

As evident from table 5.4, the price reduction as demand increases depends on the nature of the tariff schedules for each distributor. This gives rise to changes in price relativities that vary with utility.

One specific reason for the differences is the use of block charges overseas where prices fall as annual consumption increases. For example, the price between LB1 and LB2 for Penn Power falls significantly because their tariff schedule for LB1 and LB2 has block charges. At the annual consumption level implicit in LB1, only 20 per cent of electricity was purchased at the lowest per unit rate of 3.3 cents/kWh, whilst for the consumption pattern specified in LB2, 65 per cent of annual consumption was at this rate. Dayton P&L has a relatively high demand charge so when this is spread across a higher level of annual consumption (2628MWh instead of 1314MWh), per unit electricity costs fall steeply.

Most of the Australian utilities record only small reductions in electricity prices between LB1 and LB2. The reason for this can be traced back to the way Australian electricity prices for large customers are structured. Neither the network charge nor the energy charge components of the cost of electricity incorporate block rates.

In the US, however, block charges are the norm. As such, the variable cost of electricity in the US falls as annual consumption rises, whereas in Australia it remains constant. This means that in the US, there are two factors working in favour of lower per unit costs when volumes rise — lower per-unit energy charges and the impact of spreading fixed costs over a greater volume.

Within Australia, the price of electricity for utilities operating in South Australia and Queensland does not fall by as much as it does in other parts of the country. Energy charges form a large proportion of the total cost of electricity in these States, and they do not change with the level of annual consumption. With network charges forming a smaller proportion of the overall cost of electricity in South Australia and Queensland, there is less scope for fixed network charges to be spread over a greater volume of electricity.

The only overseas utility which records a small reduction in the cost of electricity is Empire District. Variable charges for this utility are quite high, there is little variation in the energy rates regardless of volume, and demand charges are quite low. As such, the proportion of fixed charges being spread across higher volumes is low, limiting the fall in the per-unit price of electricity.

A similar trend occurs when comparing the price reduction between LB3 and LB4. For example, the costs of electricity provided by Penn Power again falls significantly. With the annual consumption level implicit in LB3, only 20 per cent of electricity was purchased at the lowest per unit rate of 3.3 cents/kWh. By contrast, for the consumption pattern specified in LB4, 65 per cent of annual consumption was charged at this lowest rate. Comparing the price reduction between LB5 and LB6 for Penn Power, 20 per cent of annual consumption was purchased at the lowest per unit rate of 3.3 cents/kWh compared with 65 per cent in LB6.

Another source of variation is the use of fixed voltage charges by some utilities. For example, in contrast to the small price reduction between LB1 and LB2, Empire District recorded a large reduction in the price of electricity between LB3 and LB4. This price reduction is much greater because Empire District's High Voltage tariff schedule is structured such that demand-based charges comprise over 60 per cent of the price. Therefore, increasing annual consumption of electricity from 1314MWh to 2628MWh reduces the impact of the fixed charges, causing electricity prices to fall quite steeply. The High Voltage tariff schedule comprised lower energy rates and fixed costs than the Low Voltage tariff schedule, ensuring a significant reduction in the price as volumes rise.

The tariff schedule for Dayton P&L has a single energy rate combined with a demand charge. These supply costs represent 70 per cent of the charges of supplying LB5. The increase in annual consumption of electricity from 6570MWh to 13 140MWh (whilst keeping peak demand unchanged) reduces the impact of these fixed charges and causes the overall average annual price to fall by 30 per cent.

Increasing load factor to 80 per cent

The electricity bundles described in section 5.1 represent the consumption of electricity at 500, 1000 and 2500kW peak demand, at 30 and 60 per cent load factors. This section examines the impact of increasing load factors to 80 per cent for these three sets of peak demand (see table 5.5).

Table 5.5 **Eighty per cent load factor, large business consumption bundles**

Bundle name	*Peak demand*	*Load factor*	*Consumption in off-peak periods*[a]	*Annual consumption*
	kW	per cent	per cent	MWh
ELB1	500	80	55.0	3504
ELB2	1000	80	55.0	7008
ELB3	2500	80	56.1	17 520

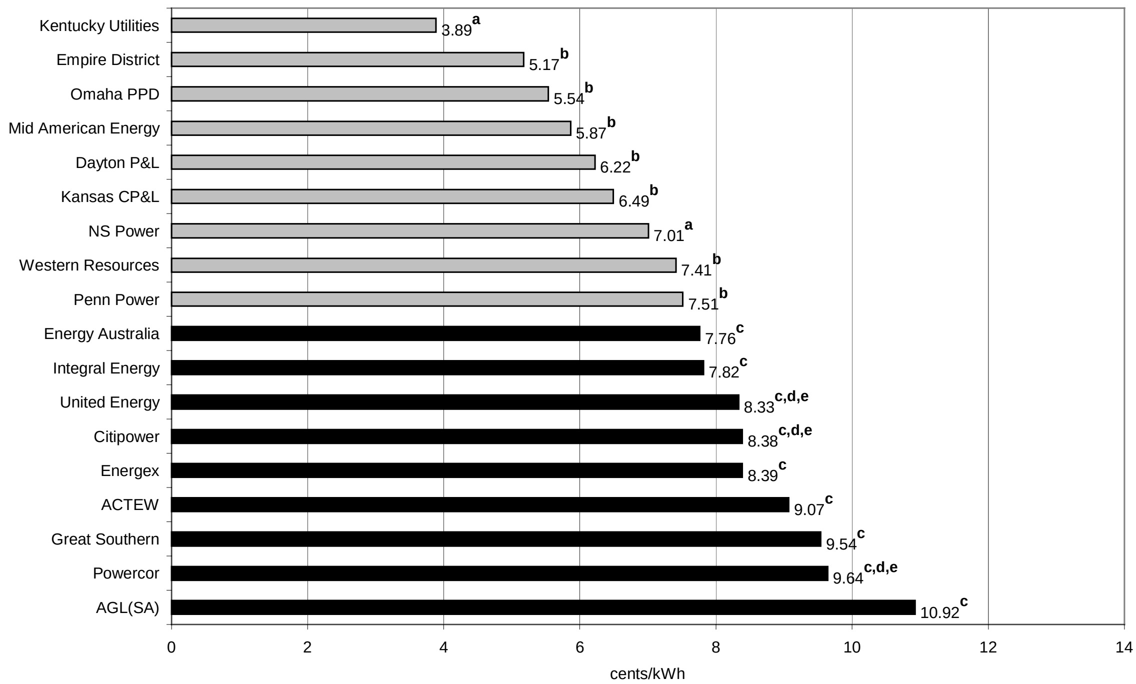
Note These are the off-peak percentages used by the ESAA. Where a utility offers off-peak rates for a different number of hours to that assumed by the ESAA, these percentages are adjusted accordingly.

Source: ESAA (2000a).

Bundle ELB1

Electricity consumption bundle ELB1 with a load factor of 80 per cent was compared with LB1 and LB2, where peak demand is 500kW and the load factors are 30 and 60 per cent. Electricity prices for ELB1 are shown in figure 5.10.

Figure 5.10 **Unadjusted average price index for ELB1, Australian dollars, October 2000**



Note ELB1 has a peak demand of 500kW, a load factor of 80 per cent, a consumption in off-peak periods of 55 per cent and an annual consumption of 3504MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge. **b** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **c** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **d** The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent.

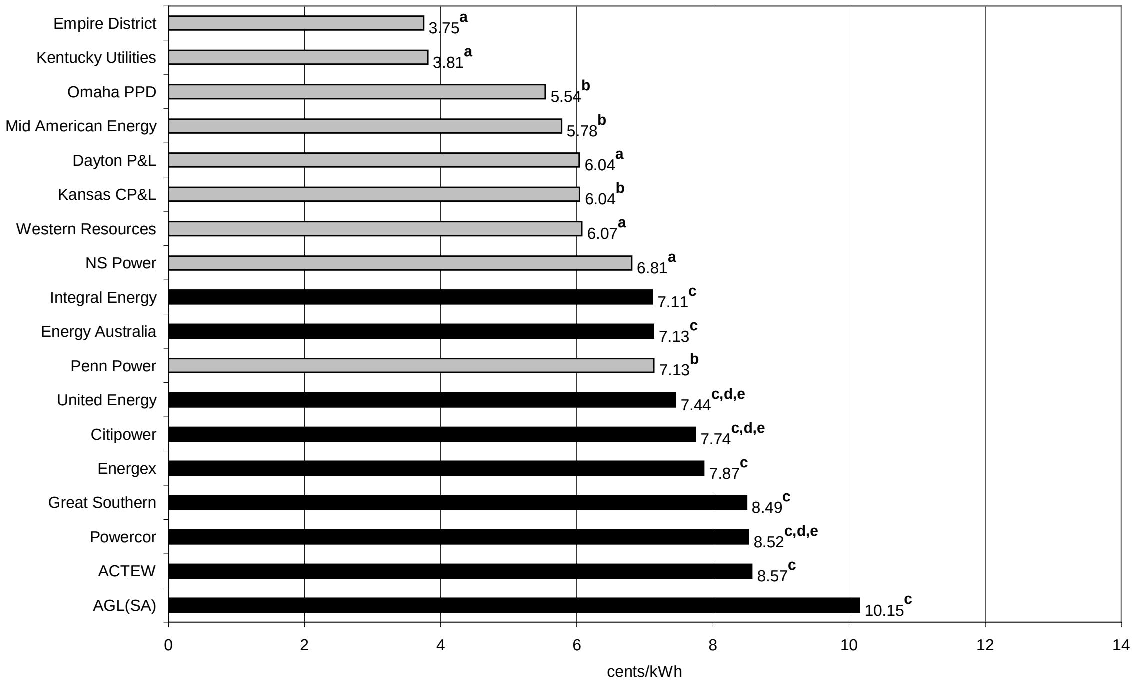
Data source: PC estimates.

The improvement in overseas utility ranking evident when comparing bundles LB1 and LB2 continues when the load factor is increased to 80 per cent (bundle ELB1). In fact, the overseas utilities dominate, with every overseas utility having lower prices than any of the Australian utilities.

Bundle ELB2

Electricity consumption bundle ELB2 was compared with LB3 and LB4, where peak demand is 1000kW and the load factors are 30 to 60 per cent. Electricity prices for ELB2 are reported in figure 5.11.

Figure 5.11 **Unadjusted average price index for ELB2, Australian dollars, October 2000**



Note ELB2 has a peak demand of 1000kW, a load factor of 80 per cent, a consumption in off-peak periods of 55 per cent and an annual consumption of 7008MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge. **b** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **c** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **d** The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent.

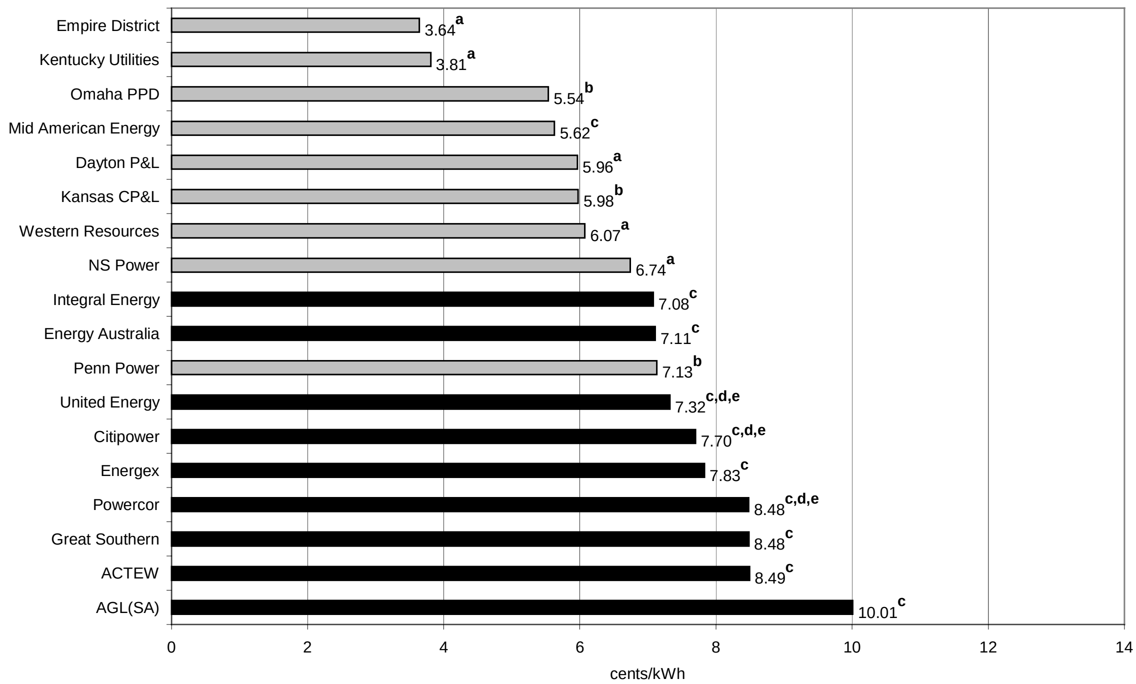
Data source: PC estimates.

The rankings of the overseas utilities improves as peak demand increases. The exception was Penn Power's prices that increase in relative terms to be higher than those of two Australian utilities.

Bundle ELB3

Electricity consumption bundle ELB3 can be thought of as an extension of the series LB5 and LB6 where peak demand is 2500kW and the load factors are 30 and 60 per cent. Electricity prices for ELB3 are reported in figure 5.12.

Figure 5.12 **Unadjusted average price index for ELB3, Australian dollars, October 2000**



Note ELB3 has a peak demand of 2500kW, a load factor of 80 per cent, a consumption in off-peak periods of 56.1 per cent and an annual consumption of 17 520MWh. Prices are an index of the price of electricity relative to other goods and services in that country in A$ using PPP exchange rates. The price index is valued at October 2000 prices, based on the tariff rate that minimised the cost of the bundle to the customer. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge. **b** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **c** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **d** The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent.

Data source: PC estimates.

Once again, prices generally become relatively cheaper than those of Australian utilities as the load factor is increased.

In summary, the sensitivity analysis at the 80 per cent load factor improves the rankings of the overseas utilities relative to Australian utilities.

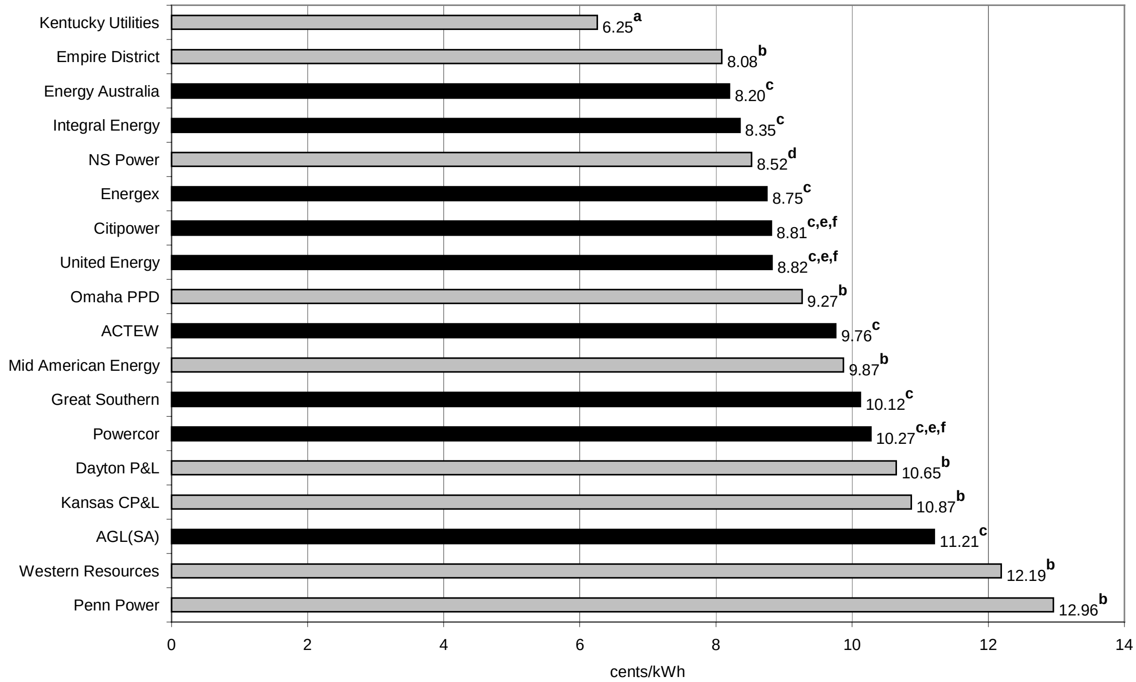
Changing the basis for currency conversion

The price comparisons have been conducted using PPP rates to convert the cost of electricity in local currency to Australian dollars as a common unit of account. These price comparisons were recalculated using market exchange rates for bundles LB2, LB4 and LB6, using the exchange rates from table 3.5 in chapter 3.

The effect of using market exchange rates rather than PPPs on the three large business bundles can be seen in figures 5.13, 5.14 and 5.15. The market exchange rate between Australia and the US, for example, was lower than the PPP rate in October 2000. Consequently, the local price of electricity in the US converts into more Australian dollars than at PPP rates.

The effect of using market exchange rates is to improve the position of the Australian utilities relative to those in the US. However, for reasons discussed in chapter 3, the use of market exchange rates for currency conversion has a number of major disadvantages.

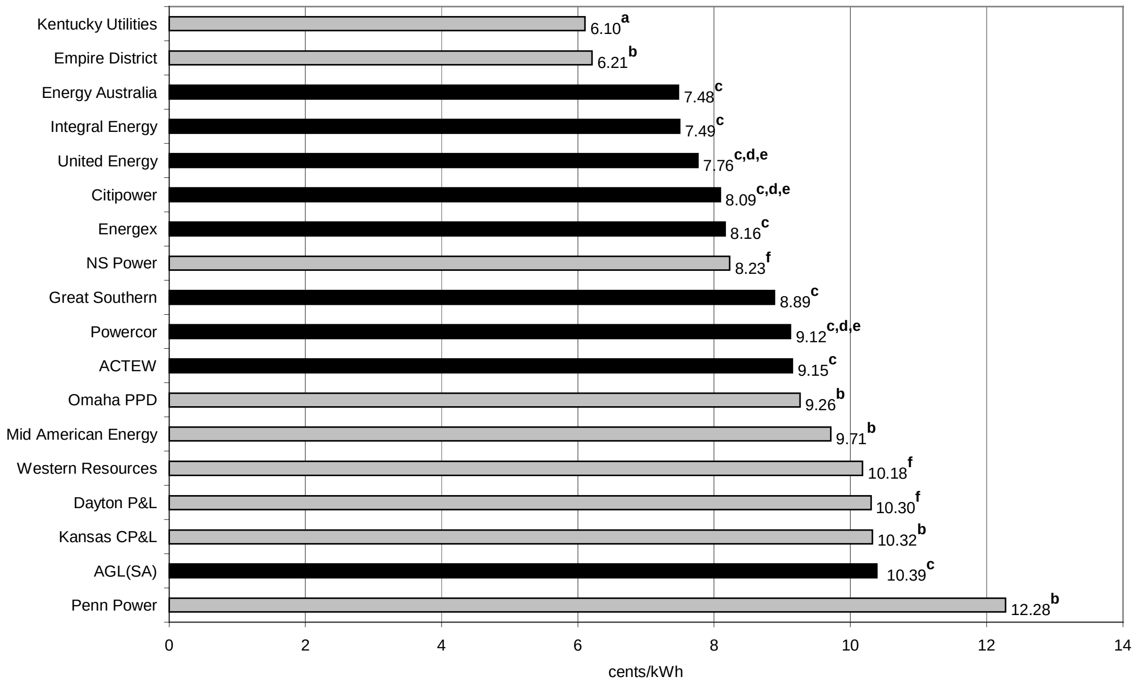
Figure 5.13 **Unadjusted average price index for LB2 using market exchange rates, Australian dollars, October 2000**



Note LB2 has a peak demand of 500kW, a load factor of 60 per cent, a consumption in off-peak periods of 46.5 per cent and an annual consumption of 2628MWh. Prices are converted to A$ using market exchange rates applicable at 31 October 2000. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, State and/or local taxes where applicable. **a** Time-of-use tariffs produced the lowest average price per kWh. **b** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **c** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **d** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge. **e** The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **f** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent.

Data source: PC estimates.

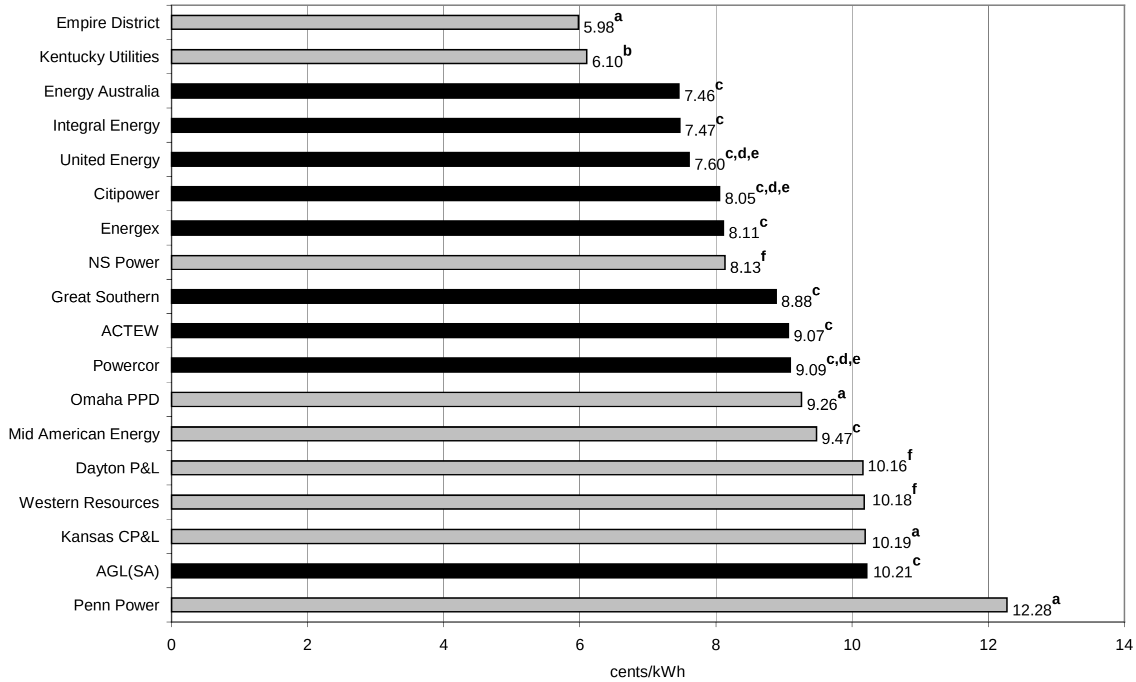
Figure 5.14 **Unadjusted average price index for LB4 using market exchange rates, Australian dollars, October 2000**



Note LB4 has a peak demand of 1000kW, a load factor of 60 per cent, a consumption in off-peak periods of 46.5 per cent and an annual consumption of 5256MWh. Prices are converted to A$ using market exchange rates applicable at 31 October 2000. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** Time-of-use tariffs produced the lowest average price per kWh. **b** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **c** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **d** The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. **f** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge.

Data source: PC estimates.

Figure 5.15 **Unadjusted average price index for LB6 using market exchange rates, Australian dollars, October 2000**



Note LB6 has a peak demand of 2500kW, a load factor of 60 per cent, a consumption in off-peak periods of 46.9 per cent and an annual consumption of 13 140MWh. Prices are converted to A$ using market exchange rates applicable at 31 October 2000. Prices do not indicate relative efficiency because there are significant cost differences caused by factors outside the control of the utilities. All prices include federal, state and/or local taxes where applicable. **a** The lowest average price per kWh is based on a block tariff that incorporated a demand charge. **b** Time-of-use tariffs produced the lowest average price per kWh. **c** The lowest average price per kWh is based on a time-of-use tariff that incorporated a demand charge. **d** The network charges used in the calculation of the Victorian DBs prices were based on tariff rates applicable at October 2000 and therefore do not reflect the changes to tariff rates introduced on 1 January 2001. **e** In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices is: Citipower 9.85 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. **f** The lowest average price per kWh is based on a flat rate tariff combined with a demand charge.

Data source: PC estimates.

Impact of revised Victorian tariff schedule

On 1 January 2001, a new tariff schedule was introduced for the Victorian Distributors. The new tariffs impact upon the network charges used in the calculation of the prices and result in only minor changes in the relative rankings (see table 5.6).

Table 5.6 **Unadjusted average price index for revised Powercor tariffs: LB1 to LB6, Australian dollars, January 2001**

Consumption bundle	*Unrevised unadjusted prices October 2000*	*Revised unadjusted prices January 2001*
	c/kWh	c/kWh
LB1	12.56	11.21
LB2	10.27	9.70
LB3	11.28	10.05
LB4	9.12	8.63
LB5	11.09	9.92
LB6	9.09	8.61

Note Prices include federal, state and/or local taxes where applicable. Prices for Powercor were calculated using tariffs rates applicable at January 2001. In Victoria, marginal variation on allowable GST pass-through results in a small variation on final prices between distributors. GST price impact on regulated electricity prices for Powercor is 9.87 per cent.

Source: PC estimates.

5.4 In summary

Despite the considerable diversity in the electricity bundles between chapters 4 and 5, Australian utility price relativities remain generally stable. This suggests that the conclusions drawn from this study are reasonably robust.

As the size of annual consumption increases, overseas utilities tend to improve their rankings. Unlike Australian utilities, overseas utilities incorporate block charges and/or demand charges. This leads to significant reductions in price as annual consumption rises.

Sensitivity analysis using a higher level of peak demand and a higher load factor produced only a minor change in the ranking of Australian and overseas utilities.

6 Quality of service

Higher quality of service usually requires additional capital and recurrent expenditure. Consequently, differences in quality of service among utilities, such as interruptions to supply, can be expected to affect relative prices as well as costs.

Utility prices should be adjusted to reflect cost differences derived from different quality of service if relative performance is to be inferred from prices. For example, the price of a rural utility would have to be adjusted upward, if its prices are to be compared with those of an urban utility with a higher quality of service.

From a consumer outcome perspective — a focus of this study— the issue is whether utilities have arrived at an efficient quality of service–price tradeoff. That is, whether large service quality differences, which exist between urban and rural utilities, are generally consistent with customer quality of service preferences — determined by both the cost of quality and the costs of disruptions and voltage fluctuations.

Prima facie, it is possible that utilities could reduce their costs and increase their profitability by lowering quality of supply. However, at best, any reduction in quality of services would only produce short-term gains to the utility. Most of the utilities studied have been regulated over many years by governments, both as owners and regulators. Consequently, it was assumed that electricity prices largely reflect the cost of the quality provided.

For this chapter, the likely size of an adjustment to price required to account for any difference in quality of services or departure from a preferred quality of service–price package was examined. Specifically, the size of adjustments relative to the prices measured in chapters 3, 4 and 5 were estimated.

Quality of service is reported in terms of the reliability of distribution networks, using reliability indexes. This is followed by an examination of the cost of improving reliability and the willingness of customers to pay for a more reliable electricity supply. This was done in order to ascertain the likely significance of differences in quality of service and any departures from an efficient quality of service–price package.

6.1 Definitions and nature

Quality of service encompasses supply quality, reliability and customer service.

Supply quality

Supply quality refers to how well the flow of electricity serves the customer in terms of the voltage and frequency characteristics of the electricity supplied. There are a number of factors that can affect the voltage and frequency of an electricity supply (see table 6.1).

Electrical equipment operates at a rated voltage (nameplate) level, but voltage levels can fluctuate. A deviation from that nominal voltage level can affect the performance of the device, even though the fluctuation does not exceed the voltage range specified by standards.

Overhead earth-wires on critical transmission feeders, surge arrestors, relays and insulation are all used to prevent or reduce voltage fluctuations. For example, to restore normal operating conditions, relays can initiate control action by energising circuit breakers that have cut out.

Another aspect of supply quality is frequency fluctuation or a deviation of a power system's frequency from its specified nominal value. A frequency fluctuation occurs when electrical energy supply is not equal to the consumption at each moment in time. Automatic load frequency control devices are used to minimise power imbalances and hence frequency fluctuations.[1] Notwithstanding these supply quality problems, a power system is mostly found in its normal state, with frequency and voltage at the prescribed level.

1 The National Electricity Code and the frequency standards set by the National Electricity Code Administrator's Reliability Panel, establish frequency values between 47 Hertz (Hz) and 52Hz for 'multiple contingencies' (more than one generator tripped) and a 'normal contingency band' of 49.9Hz to 50.1Hz.

Table 6.1 **Factors affecting quality of supply**

Factors	*Definition*
Voltage fluctuation (flickers)	A series of random voltage changes, the magnitude of which does not normally exceed the voltage range specified by standards. For example, lamps flicker due to voltage fluctuations caused by operation of such items as welding machines and wind power generators.
Power surge (spike)	A high voltage increase by several thousand volts that lasts for less than 1/1000ths of a second. Spikes are caused by lightning strikes or by simply turning equipment on and off. Spikes are also known as transients and they can damage sensitive electronic equipment.
Power dip (sags)	A reduction in voltage that lasts up to 15 seconds. Sags can shut down and possibly harm sensitive electronic equipment. These are caused by temporary power drains when other equipment starts up or overloads an electrical system. Examples include energising of heavy loads or starting a large motor.
Frequency fluctuation	The deviation of frequency from its specified nominal value as a result of system energy imbalance. Frequency fluctuation can be caused by a large source of generation going off-line, a fault in the bulk power transmission system, or a large block of load being disconnected.
Harmonic distortion	Harmonics are distortions of voltage or current waveform due to electromagnetic interference from radio or television broadcasts or the operation of electronic switches, fax machines, copiers and computer equipment. Harmonics result in computer monitor screen distortion.

Sources: Dugan, McGranaghan and Beatly (1997), Energy Australia (1998a).

Reliability

The term reliability refers to the ability of the various power system components — generation, transmission and distribution — to deliver electric power to all points of consumption. A failure in generation may disrupt customer supply, requiring a co-ordinated response to restore system-wide stability (see box 6.1). This kind of failure can cover a large geographical area. In contrast, a failure in the distribution system generally results in disruptions on a more localised basis.

Box 6.1 **Electricity supply interruption due to generation failure**

On 23 January 2000, two 660MW generating units in NSW tripped, Bayswater Unit 2 and Mt. Piper Unit 1. The Bayswater generation unit (Macquarie Generation) failed due to low boiler airflow during a maintenance procedure and Mt Piper (Delta Electricity) tripped because of failure in a DC power supply associated with the boiler. As a consequence, frequency fluctuated between 49.0Hz and 49.9Hz which further tripped the Torrens Island Unit B4 in South Australia and Newport generating unit in Victoria. The loss of generators resulted in load shedding of small industrial loads in South Australia, Tomago Aluminium smelter potline in New South Wales and Point Henry smelter potline in Victoria.

The arrangements that independent market operators have in place with the generators can also affect reliability. To maintain system load requirement and hence frequency, the National Electricity Market Management Company Ltd (NEMMCO) has various agreements with the generating units. For example, Automatic Generation Control (AGC) is a response protocol for generating units when signals are sent by NEMMCO to ensure that system frequency recovers to and is maintained within the normal levels set by the Reliability Panel. Such agreements are known as ancillary service agreements.

Of the nine generators that did not trip at the time of the 23 January incident, five withdrew their AGC ancillary services, leaving only 42.5MW of the 250MW normally available to recover frequency under the NEMMCO ancillary service agreements.

Source: NEMMCO (2000).

Generation

Shortages of available generating capacity can lead to shortages of supply particularly during peak periods, reducing reliability. Reductions or loss of supply can result in brownouts (causing lights to dim) and blackouts. Commonly used measures of generation reliability are:

- *Loss of Load Expected (LOLE)* — indicates the expected number of days in the year when the daily peak demand exceeds the available generating capacity. LOLE is also commonly referred to as Loss of Load Probability; and
- *Forced Outage Rate (FOR)* — indicates the percentage of time that capacity is lost due to forced outage. A forced outage is defined as an unplanned component failure or other condition that requires a unit to be removed from service.

The level of reserve capacity in generation influences the reliability of electricity supply. High levels of reserve capacity can increase reliability levels, but has associated cost implications (see chapter 7). Generators' reliability can also be influenced by unexpectedly high peak demands, which cause the level of demand to exceed available capacity. A commonly used measure for outages caused by excess demand is the number of days interruption in every seven, ten or 12 years depending on the utility (Campbell 1982).

Transmission

Quality of service of electricity supply depends on reliable transmission services. For example, overall reliability is reduced when transmission systems are overloaded in periods of heavy demand.

Two of the most common measures of transmission reliability are:

- *System minutes lost* — a measure of the energy (MW) not supplied if the whole system shuts down for one minute. It is defined as 60 times the energy not supplied because of unplanned outages from all causes and on all parts of the network (MWh) divided by annual system maximum demand (MW). This measure indicates the overall system reliability, combined with the effectiveness of network design and maintenance.
- *Circuit availability (per cent)* — is a measure that indicates the extent to which circuits are available for power transfer, but it does not indicate if that availability is at a time when power transfer is required. It is defined as 100 times the sum of available hours for each transmission circuit per annum, divided by 8760 hours in a year, times the total number of transmission circuits (Centre for Advanced Engineering 1993).

Comparisons of intrinsic reliability on the basis of these measures are not straight forward because no two networks are the same. For example, where a system is more interconnected with another, its reliability is enhanced because outages on one transmission line can be compensated by redirecting power flows along another line.[2]

Transformers, which are part of transmission networks, can also result in power interruption as a result of faults. An example of a transformer and high voltage cable breakdown is the incident at ComEd's Jefferson substation (Chicago USA) from 30 July to 12 August 2000. Loss of three transformers and several 69kV cable faults resulted in 3000 customers experiencing outages (DOE(US) 2000).

2 The extent to which this can be achieved is limited by the available capacity of compensating transmission line and the current already flowing through it.

Distribution

A large percentage of electricity supply reliability problems are associated with the distribution network. For example, US national statistics indicate that over 85 per cent of supply interruptions occur because of distribution system outages (Sanghvi 1990). Of the remainder, substation failures account for 9 per cent, transmission 4 per cent and generation for 2 per cent.

The reliability of distribution systems is related to temperature and network age. Equipment exposed to severe climatic conditions may fail frequently and falling tree branches associated with storms can also cause large-scale outages. Aged networks typically have more frequent breakdowns than newer networks. Other characteristics of the distribution system may also affect reliability, such as the choice of materials used. For example, the use of concrete poles and steel cross arms in parts of the Victorian distribution network increases the incidence of animal-related interruptions (ORG(Vic) 2000c).

The design of distribution network connection (radial, banked or meshed) also affects reliability. The difference in these network types is in the level of interconnection to the primary main that carries energy at high voltage from substation to the distribution transformer. Greater interconnection enables greater segmentation and isolation of faults, thereby reducing the impact of outages.

The rate of interruption to overhead networks is usually greater than for underground cable networks because of exposure to falling trees, wind, ice and automobile collisions with power poles. For example, for Integral Energy, the annual number of interruptions is 30.3 per 100 kilometres of line for high voltage overhead cables and 2.8 interruptions for underground cables (Sinclair Knight Mertz 1998). However, despite greater protection from these hazards, underground networks take more time to repair than overhead networks, thereby increasing the duration of the, albeit fewer, outages.

Maintenance

The maintenance policy which a utility has in place affects the duration and frequency of outages. For example, the duration of outages can be lengthened where inadequate maintenance programs result in undermanning of maintenance services and sufficient manpower is not available to restore equipment to service quickly.

In the case of the distribution network, supervisory control and data acquisition (SCADA) and distribution automation systems, permit more centralised monitoring and control of power distribution systems, reducing the extent and duration of interruptions.

Customer service

The quality of an electricity supply is also affected by the response of customer services to enquiries, complaints and customer connection requests. Some utilities establish their own in-house standards for customer service. For example, Energy Service (the licensed retail business of Integral Energy) has a target of answering 90 per cent of customer calls within 60 seconds.

6.2 Quality of service comparisons at distribution level

Measures of the reliability of distribution services are only available on the frequency and duration of supply interruption, both sustained and momentary. Information is not generally available for supply quality measures such as voltage sags, dips and surges.[3]

The following indexes are used for reliability measurement:

- *System Average Interruption Duration Index (SAIDI)* — the average duration a customer is without power in a year, expressed in minutes. It is calculated using the total number of customers affected times duration of outage divided by total number of customers served. The smaller the number the better the system reliability.
- *System Average Interruption Frequency Index (SAIFI)* — indicates the average number of interruptions that customers experience in a year. It is calculated using the number of customers interrupted times the number of interruptions, divided by the total number of customers served. Usually only interruptions of longer than one minute are counted.[4] The lower the number the better the system reliability.
- *Customer Average Interruption Duration Index (CAIDI)* — the average duration of outage for customers who experience an interruption. It is calculated using the sum of customer interruption duration divided by total number of customers interrupted. The lower the number the better the system reliability.
- *Customer Average Interruption Frequency Index (CAIFI)* — the number of interruptions that affected customers experienced in a year. It is calculated using the total number of customer interruptions divided by number of customers who

3 System Average Root Mean Squared Variation Frequency Index ($SARFI_x$) is the average number of short duration Root Mean Squared (RMS) variation events with a voltage magnitude of less than a specified percentage of nominal voltage.

4 This is because interruptions of less than one minute will be included in the MAIFI measure, subject to the utility’s definition of ‘momentary’ interruption.

experienced an interruption. The lower the number the better the system reliability.

- *Average System Availability Index (ASAI)* — the availability of power (in hours) compared to customer demand for power during a year measured in percentage terms. It is calculated using the customer hours of available service divided by customer hours service demand. The higher the percentage the better the system reliability.
- *Momentary Average Interruption Frequency Index (MAIFI)* — the number of short duration interruptions that a customer experienced. It is calculated using the total number of customer interruptions of less than one minute divided by the total number of customers. The lower the number the better the system reliability.

The main difference between SAIDI and SAIFI, and CAIDI and CAIFI is that the first two relate to the distribution system as a whole, whereas the latter two relate only to those customers whose power has been interrupted.

Factors affecting reliability indexes

There are various factors to be taken into account when comparing reliability indexes between utilities.

SAIDI, SAIFI and CAIDI are inter-related. The average duration that a customer is without power (in a year) depends on the average duration of each particular outage and the frequency at which outages occur.

To some extent utilities can control the average duration of any particular outage (CAIDI) as it partly depends on a utility's supply restoration procedures. However, they do not possess the same degree of control over the frequency of outages (SAIFI), as outages are most often caused by factors such as severe weather and climatic conditions and motor vehicle accidents.

The number of customers connected to a distribution line can affect the SAIDI and SAIFI indicators. For example, a utility with a large number of customers on a feeder line will have smaller values for SAIDI and SAIFI than another utility with fewer customers, provided both lines have the same duration and number of interruptions. This indicates that a distinction should be made between CBD, urban and rural areas because customer density on networks varies significantly between these areas. Differentiation of areas according to customer density in this way, improves the comparability of reliability measures between utilities.

The length of not just feeder lines but of the entire distribution network, also affects these indexes. Distributors with short meshed networks (highly urbanised) will have better reliability than those with long lines (rural), where it takes longer to find faults and make repairs and electricity is usually only supplied from one source.

Reliability indexes are often measured inconsistently, making comparisons between utilities difficult. Some utilities include storm-caused interruptions in the calculation of their quality of service indicators and others do not. Where storm-caused interruptions are included in the calculation of indicators, there is likely to be more variation from year-to-year.

The criteria for excluding storm-caused interruptions may vary among utilities. For example, storm-caused interruptions are excluded from reliability indicators for Penn Power if the service interruption affects at least 10 per cent of the customers in an operating area for a duration of five minutes or greater. For utilities operating in NSW, storm-caused interruptions are excluded if there is a severe thunderstorm or gale force winds (wind speeds in excess of 80 km per hour) which cause widespread extensive damage and lead to call centre customer calls reaching overflow capacity.

Another inconsistency lies in the recording procedures used. Some utilities do not include interruptions of less than five minutes in the calculation of the reliability indexes (SAIDI, SAIFI, CAIDI and CAIFI) but include them in MAIFI. Other utilities include interruption of more than one minute in the calculation of the reliability indexes (SAIDI, SAIFI, CAIDI and CAIFI) and less than one minute in MAIFI. Moreover, some utilities exclude outages if the customer is given two days notice of a planned outage.[5]

Reliability comparisons

Data on several quality of service indicators was available for most of the utilities studied (see table 6.2). However, data on CAIFI, ASAI and MAIFI was not generally available.

Reliability indicators such as SAIDI and SAIFI are averages. However, the frequency and duration of interruptions that a customer experiences may differ significantly across a distributor's network. For example, the average frequency of interruption including storms for customers within different regions of Integral Energy's service area in 1999-00 varied from 1.02 to 5.24 interruptions per customer (DOE(NSW) 2000). The overall average frequency of interruption including storms for Integral Energy's customers was 2.13.

5 Energy Australia also excludes interruptions of less than one minute caused by major storms in the calculation of SAIDI.

Table 6.2 **Utilities distribution reliability, 1999**

Utility	*SAIDI*	*SAIFI*	*CAIDI*
Kansas CP&L[a]	247	1.13	218
NS Power[a]	245	2.10	118
Powercor	237	5.19	46
Western Resources[a,b]	229	1.95	118
Great Southern[b,c]	221	1.90	116
Penn Power[b]	144	1.31	110
Energex[b,c]	142	1.80	79
Western Power[b,c]	136	1.28	106
Integral Energy[b,c]	124	1.23	101
Israel Electric[b]	118	3.30	36
Empire District	108	2.03	53
United Energy	78	2.88	27
Energy Australia[b,c]	74	1.27	58
ETSA Utilities[b,c]	69	0.77	89
ACTEW[d]	68	1.21	56
Omaha PPD[a,b]	61	1.30	47
Mid American Energy	50	1.00	50
Citipower	45	0.89	51
Bewag	**n.a.**	**n.a.**	**n.a.**
Dayton P&L	**n.a.**	**n.a.**	**n.a.**
Kentucky Utilities	**n.a.**	**n.a.**	**n.a.**

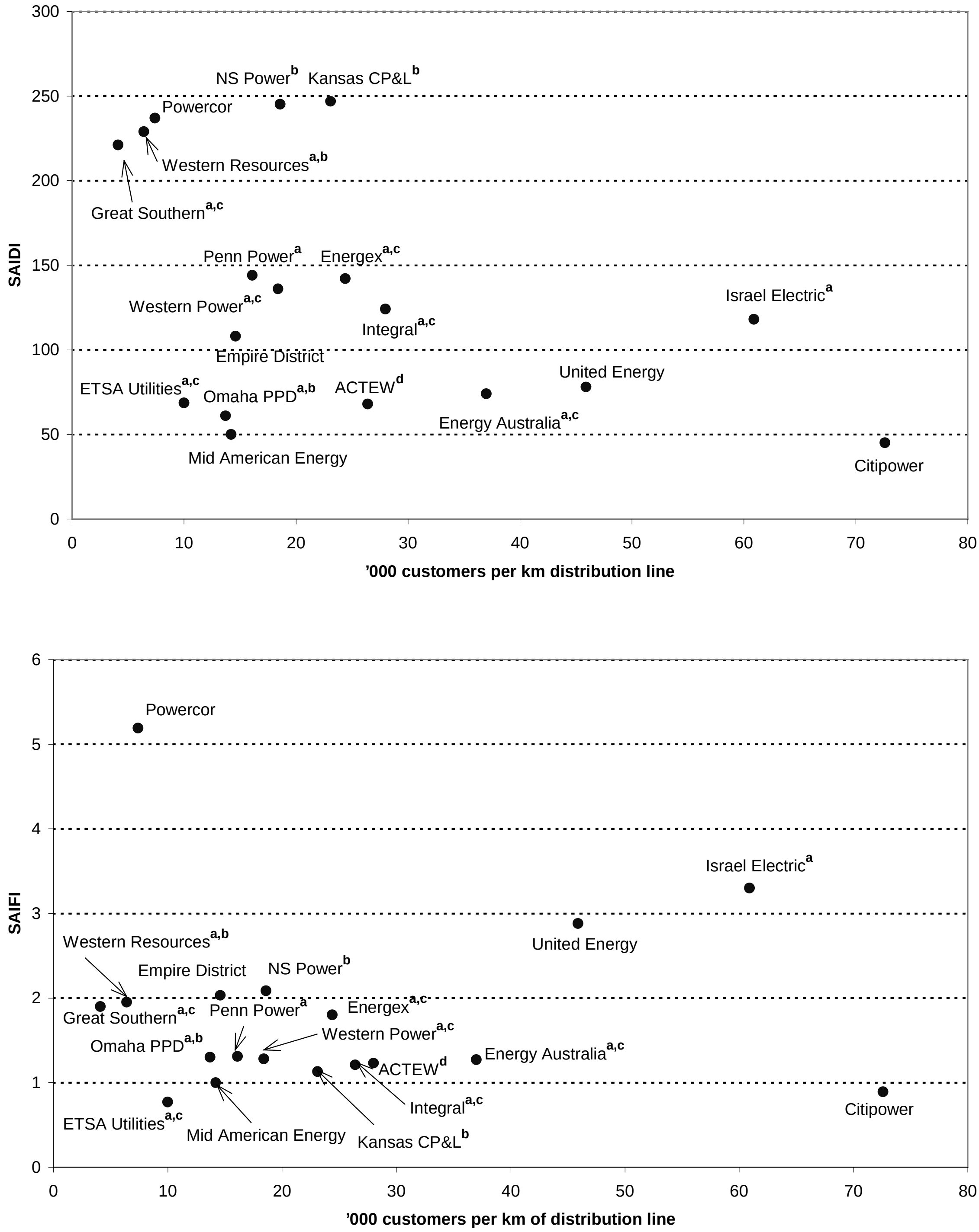
n.a. Not available. [a] 2000. [b] Excludes storms and other major events. [c] 1999-2000. [d] 1997-98.

Sources: Data provided by utilities; DOE(NSW) (2001); ORG(Vic) (2000a); IPARC (1999); Energex (2000); Stump, L., Iowa Utilities Board, pers. comm., 29 May 2001; Loper, B., Pennsylvania Public Utility Commission, pers. comm., 25 May 2001; Ketter, J., Missouri Public Service Commission, pers. comm., 2 May 2001; Wolf, J., Kansas CP&L, pers. comm., 19 April 2001.

To the extent possible, the data in table 6.2 are reported on a consistent basis. However, care should be taken when making comparisons between utilities because of differences in the construction of indicators and differences in operating environment. For example, nine of the 18 utilities for which quality of service information was available include storm-caused interruptions in the calculation of reliability measures. Where storm-caused interruptions are included in the indicators, they are more likely to vary from year-to-year. The inclusion of storms also leads to higher reliability indicator values — indicating lower levels of reliability than if storm-caused interruptions are excluded.

The average duration and frequency of interruptions may be related to a utility's operating environment and network design (see figure 6.1). For example, supplying electricity to less densely populated areas generally involves longer distribution line lengths. This can lead to greater exposure to climatic conditions, such as storms. The duration of interruptions can also be longer if maintenance crews have problems locating faults and have to travel further to repair faults.

Figure 6.1 **Distribution reliability indicators and customer density, 1999**



n.a. Not available. **a** 2000. **b** Excludes storms and other major events. **c** 1999-2000. **d** 1997-98.

Sources: Data provided by utilities; DOE(NSW) (2001); ORG(Vic) (2000a); IPARC (1999); Energex (2000); Stump, L., Iowa Utilities Board, pers. comm., 29 May 2001; Loper, B., Pennsylvania Public Utility Commission, pers. comm., 25 May 2001; Ketter, J., Missouri Public Service Commission, pers. comm., 2 May 2001; Wolf, J., Kansas CP&L, pers. comm., 19 April 2001.

There were no statistically significant rank correlations between the number of customers per kilometre of distribution line and SAIDI or SAIFI.[6]

Although reliability levels may vary with customer density, there does not appear to be a pattern of overseas utilities having significantly lower levels of reliability (see figure 6.2). *Prima facie*, the lower prices of some overseas utilities have not been achieved by having a less reliable supply. However, with data for only one year and inconsistencies in the way the indicators are measured, this evidence is inconclusive.

To test the relationship between quality of service and the price outcomes, rank correlations (using Spearman's technique) were performed on the rankings of the utilities in figure 6.2 and the utility rankings resulting from the price outcomes in chapters 3, 4 and 5.

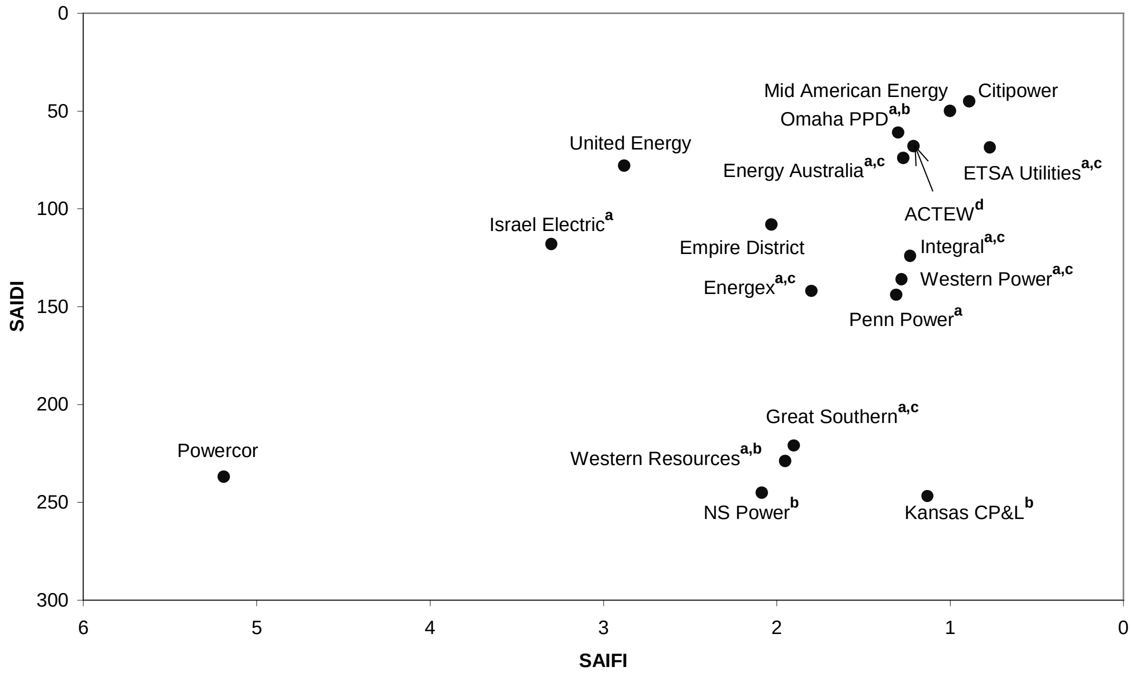
No significant relationship between prices and SAIFI or SAIDI was observed for any of the consumption bundles. A significant relationship was only observed between CAIDI and four of the consumption bundles (three residential and one small business).

Further insights into the relationship, if any, between prices and service quality can be gained by examining the cost of improving the reliability of distribution networks and the willingness of customers to pay for these improvements. Willingness to pay is relevant because utilities will not invest in service quality improvements unless they believe they can recover the costs by convincing regulators that demand exists to justify the increased capital expenditure.

The cost of improving reliability at the margin provides an indication of the materiality of any difference in quality of service. Willingness to pay provides an indication of the ability of utilities to recover the cost of reliability improvements and, hence, the likelihood of prices being affected.

6 Spearman's rank correlation coefficient was used to measure the absolute differences in the ranking of utilities by reliability measure and density measures such as the number of customers per kilometre of distribution line. The coefficient can be used to determine whether there is a negative, positive or no relationship between the ranked individuals or characteristics (Gujarati 1988). Critical values for statistical significance were calculated at the 95 per cent confidence level.

Figure 6.2 **Utilities distribution reliability, 1999**



n.a. Not available. **a** 2000. **b** Excludes storms and other major events. **c** 1999-2000. **d** 1997-98.

Sources: Data provided by utilities; DOE(NSW) (2001); ORG(Vic) (2000a); IPARC (1999); Energex (2000); Stump, L., Iowa Utilities Board, pers. comm., 29 May 2001; Loper, B., Pennsylvania Public Utility Commission, pers. comm., 25 May 2001; Ketter, J., Missouri Public Service Commission, pers. comm., 2 May 2001; Wolf, J., Kansas CP&L, pers. comm., 19 April 2001.

6.3 Influence of quality of service on costs

The level of reliability achieved and the associated cost, depends on the network type and the level of expenditure on reliability improvement. Greater reliability can be achieved with increased expenditure. However, there is an optimal level of reliability.

> No electricity system is 100 per cent reliable. The expense required to make a system outage free would be exorbitant and beyond what customers could be expected to pay for (ORG(Vic) 1997).

Expenditure required to improve service quality

Expenditure is required to maintain or improve reliability as assets age. The amount of expenditure depends on the level of interconnection, the age of the network and the operating environment, among other things. Assessment of the cost-effectiveness of such expenditures is usually based on the engineering relationships between particular investments and their expected reliability outcome. For example:

- It has been shown that as the age of urban distribution lines and poles increases, maintenance costs must increase in order to maintain reliability (UMS Group 2000).
- Strong winds and ice storms are drivers of investment in sophisticated systems to maintain reliability.
- Lightning strikes also make a significant contribution to SAIDI, but solutions to reduce its impact, such as earth wires or undergrounding, are costly (Eastern Energy 1999).

There are diminishing returns from capital investment in reliability improvement, with some reliability projects more cost-effective than others. For example:

- Energy Australia estimates that remote control reclosers on 11/22kV overhead feeders in its urban areas would result in a maximum SAIDI reduction of 23.2 minutes at a cost of $1.8 million per minute reduction. It would also result in a maximum SAIFI improvement of 0.2273 fewer interruptions per year.
- Undergrounding of Energy Australia's overhead urban 11/22kV bare wire feeders would result in an estimated SAIDI improvement of 54 minutes at a cost of $20.3 million per minute. It would also result in a maximum SAIFI improvement of 0.99 fewer interruptions per year (Energy Australia 1998b).

Recently, as part of a distribution price review, the Victorian distributors provided the Office of the Regulator-General (ORG(Vic)) with information on the additional capital, operating and maintenance expenditure that would be required to achieve 'enhanced' service quality levels. These levels were outlined in the proposal that the distributors submitted to the ORG(Vic) as part of the price review process.

The level of additional capital and operating expenditure proposed by the distributors varied between them. For example, AGL(Vic) proposed to spend around $2 million per year on reliability improvement to reduce SAIDI by 15 minutes (from 98 minutes in 2000 to 83 minutes in 2005), whereas Eastern Energy (TXU) proposed to spend $7 million per year to reduce it by 37 minutes (from 255 minutes in 2000 to 218 minutes in 2005) (ORG(Vic) 1999, ORG(Vic) 2000b).

In their preliminary analysis of all five distributor submissions, the ORG(Vic)'s consultant (PB Power) estimated that the average capital cost of service enhancement projects proposed by all the distributors would be around $1 million per minute of reduced SAIDI (PB Power 2000).

In its final determination, the ORG(Vic) reported annualised marginal cost estimates based on submissions by the Victorian distributors in their enhanced service proposals. These savings, expressed as the cost per MWh of unserved energy saved (or the reduction in revenue foregone due to the inability to supply), are outlined in table 6.3.[7] This is more than the revenue foregone to the supplier, but less than current estimates of the value placed on continuous supply by customers.

It is sometimes argued that for the same amount of capital expenditure, a higher percentage SAIDI improvement is achievable in the urban network than in rural areas. However, figures on percentage improvement can be confounded by the baseline level being different. For example, Citipower (a predominantly urban distributor), had a SAIDI of 61 minutes in 2000, compared with Powercor's (a predominantly rural distributor) SAIDI in 2000 of 255 minutes.

Table 6.3 **Annualised marginal cost of proposed reliability improvements, 2000 to 2005**

Distributor	*SAIDI improvement*	*Cost of unserved energy saved*
	Minutes	$ per MWh
Citipower	19	10 360
AGL(Vic)	15	4 215
Eastern Energy	37	8 610
Powercor	43	9 450
United Energy – 'customer value'	47	4 755

Source: ORG(Vic) (2000b).

An alternative means of expressing the cost-effectiveness of reliability improvement is to estimate the cost per minute of SAIDI improvement. Then, for the purpose of comparing prices this cost can be converted to a cost in cents per kWh of electricity supplied.

In Citipower's case, $22.5 million is committed to improve the quality of supply and reliability over the five year period from 2001 and 2005 (ORG(Vic) 1999, table 3.7). This level of expenditure is expected to improve SAIDI by 19 minutes (or about 30 per cent from 61 minutes in 2000 to 42 minutes in 2005), at a cost of just over $1 million per minute saved (ORG(Vic) 2000b, table 2.3). Citipower's

7 These annualised marginal costs in dollars per MWh are calculated using the level of energy sales per minute and the number of minutes each utility indicated that they will improve their SAIDI over the five year determination period. The estimated amount of expenditure over the five years to achieve the improvement is then divided by the number of additional MWh sold during the cumulative minutes of SAIDI improvement over the five years.

estimated revenue over the period was $828 million. Therefore, the cost of improving reliability by this amount is equal to about 2.7 per cent of revenue, or about 0.08 cents per kWh of forecast electricity supplied (ORG(Vic) 1999, table 4.2).

In contrast, Powercor committed $30.2 million to improve reliability by 33 minutes (or just 13 per cent from 255 minutes in 2000 to 218 minutes in 2005) at a cost of around $1 million per minute saved (ORG(Vic) 2000b, table 2.3). Powercor’s estimated revenue over the period was $1.8 billion. Therefore, its cost of improving reliability by this amount is equal to about 1.7 per cent of revenue, or about 0.06 cents per kWh of electricity supplied (ORG(Vic) 1999, table 4.2).

These recent costings suggest that some quality improvement can be achieved at relatively low cost. Moreover, there is scope to install equipment that enhances the quality of electricity supply on the customer premises, rather than improving the whole network and thereby imposing costs on customers that do not require the same level of quality.

This suggests that there is little incentive to decrease prices by lowering quality of service at the margin. Even if there were systematic quality of service differences between similar utilities — contrary to the findings in section 6.2 — the price differences observed in chapters 3, 4 and 5 are unlikely to be explained by differences in quality of service.

The above analysis does not imply that lower levels of quality may be optimal for some utilities. For example, it may be efficient for rural distributors to provide lower quality of service because of the very high cost of building a network with the same level of reliability as an urban network. The relevant issue is whether a utility is minimising costs, and hence prices, while also providing a level of service quality expected by its customers.

In terms of customer outcomes, any price reductions made possible by lowering quality of service to below required levels would be offset by higher costs to the customer.

6.4 Influence of quality of service on prices

Willingness to pay for higher quality supply influences decisions to make quality enhancing investments because it affects the return that can be obtained through increased price revenue. It must be taken into account along with any reduction to operating costs that come about because of the investment, as discussed in the preceding section.

Customer willingness to pay is typically influenced by their service experience and expectations. Nevertheless, it provides another indication of the extent to which prices might vary because service quality is not at optimal levels.

Customer cost of unreliable supply

Willingness to pay for a higher quality of service often depends on the cost imposed by a lesser service. Customers see value in paying higher prices for better service if it produces savings in the costs that they would otherwise incur. These costs may include disruption to business, work or leisure pursuits and having to provide for contingency and alternative energy sources.

Direct estimation of the value placed on reliability requires an understanding of the consequences of disruption. For example, voltage surges or dips can cause damage to customers' property. Voltage sag may result in the loss of memory or data error in a computer and a voltage spike can burn out computer components. Even where devices such as un-interruptible power supply (UPS) can prevent such data loss or equipment damage, they come at a cost to the customer.

Costs of unreliable electricity supply depend on the type of customers, the duration and timing of outages and the type of appliances used by customers. For some customers the cost can be substantial. For example, supply interruptions can cause lost production and product spoilage in businesses or necessitate investment in back-up generating capacity.

A term commonly used to describe the cost of outages to users is the Value of Lost Load (VoLL). The VoLL is the average price customers are theoretically assumed to be willing to pay to maintain their supply. It is used to cap prices in the Australian National Electricity Market (NEM).

In 1997, the Victorian Power Exchange sponsored a study by Monash University into the value of supply reliability and the level of VoLL for Victorian customers (Kahn and Conlon 1997). The study findings indicate that the cost of disruptions differs according to the type of customer affected by an outage (see table 6.4).[8]

8 There have been some problems in the estimation of the VoLL. Mail survey response rates of around 10 to 20 per cent overall mean that there might not have been enough responses to obtain a representative selection of each stratified group within the sample. Further, the VoLL may be upwardly biased because respondents to a mail survey are usually individuals or organisations that have a greater interest in the loss of supply than those who place a low value on continuity of supply.

Table 6.4 **Value of Lost Load (VoLL)**

Type of customer	*VoLL*
	$ per MWh
Composite value of lost load for all customers	28 000
Residential sector	700
Commercial sector	70 000

Source: Kahn and Conlon (1997).

Sinclair Knight Merz estimated that the interruption cost incurred by a commercial customer with a 20kW demand, a 2 second interruption and using a VoLL of $45 534 per kWh (Monash study), would be $505 (Sinclair Knight Merz 1998).[9] In contrast, a residential customer with a VoLL of $2.80 per kWh, 8 hours outage time and demand of 1kW, would incur a cost of $17.44.[10]

Similarly, a study conducted for the Duke Power Company in the US by Momoh (1998) estimated that an outage lasting an hour on a summer afternoon and originating in the transmission or distribution system would cost a residential customer about A$2.07 per kWh of lost load while the average commercial customer would experience a cost of about A$45.82 per kWh of lost load.

Customer willingness to pay

Theoretically, customer willingness should be related to the perceived cost of interrupted supply discussed above.

In a discussion paper prepared for the Independent Pricing and Regulatory Tribunal (IPART) in NSW, Energy Australia described a survey of 1000 customers and the use of conjoint analysis to estimate how much customers would be prepared to pay for improved supply quality (Energy Australia 1999).[11] Their research indicated

9 This is calculated by multiplying the VoLL of the commercial customer by the 2 second duration of interruption, converted to hours, and multiplied by the assumed total demand during the outage $45 534 * 2/3600 * 20.

10 Under the NEM arrangements, VoLL is set as an average figure for all customers (currently, it is $5000 per MWh). The National Electricity Code Administrator in its first annual review recommended that the VoLL be increased in stages to $10 000 per MWh by 2001 and $20 000 per MWh by 2002.

11 Conjoint analysis assumes that customer purchase decisions are based on multiple attributes (measures of electricity supply quality in this case) that are 'considered jointly'. The technique presents customers with a selection of attributes and computer-based choices that force them to tradeoff between the levels shown and thereby implicitly value the attribute levels that describe the product.

that 28 per cent of residential customers prefer overhead cables to be underground (Energy Australia 1999).

The cost difference between having cables above or below ground is $140 per quarter, $15 for overhead and $155 for underground. This $140 increase in fixed quarterly charge is relatively expensive and is estimated to cost 2.8 cents per kWh, even for the highest consumption residential bundle of 20 000kWh per annum used for price comparisons in this study (see chapter 3).

High income households may be prepared to pay such increases, as there was evidence in the Energy Australia survey that preference for underground lines was strongly linked to household income. In contrast, household income was not strongly linked to preferences for reliability among residential users.

Strong diversity of preference between residential and small business customers for reliability improvement is apparent from the Energy Australia study. Small business customers tended to select a more expensive and reliable option than residential customers. The results indicated that 67 per cent of small businesses would pay $50 or more in a fixed quarterly charge to achieve one interruption or less per annum.[12] In contrast, only 39 per cent of residential customers were prepared to pay this amount.

A $50 increase in the fixed quarterly charge would be equal to a cost of about 0.33 cents per kWh if applied to the small business consumption bundle of 60 000kWh per annum examined in chapter 4.[13]

In the United Kingdom, the Office of Electricity Regulation (OFFER) sponsored a study by Market and Opinion Research International (MORI), to conduct a survey of domestic and business customers with maximum demand ranging from under 100kW, to more than 100kW and more than 1MW (OFFER 1999).[14] The results indicated that on average, residential customers surveyed were willing to pay A$24 on top of their current annual bill for improvements in the quality of electricity supply. The improvements included new telephone answering standards, a 3 per cent increase in the number of customers' supplies restored within 3 hours and automatic penalty payments. However, subsumed within this average was a large group (57 per cent) that did not want to spend anything at all (OFFER 1999, p. 36).

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12 Energy Australia's current average frequency of interruption is approximately two interruptions per annum (Energy Australia 1999).

13 This is calculated by dividing the total fixed charge for the year (3*$50) by total annual consumption of 60 000kWh.

14 The Office of Electricity Regulation is now the Office of Gas and Electricity Management.

For installing underground lines, for example, domestic customers were willing to pay A$14 more on top of their current bill. Businesses were prepared to pay 2.5 per cent more than their current bills for a specific improvement in quality of service, namely restoration of power within 3 hours (OFFER 1999).

The results from this kind of research can be inaccurate because customers are responding to sophisticated but nonetheless hypothetical survey questions. Although they must be treated with caution, they indicate that prices could only be increased by small amounts to improve supply reliability.

6.5 In summary

There are three elements of quality of service — quality of supply (the flow of electricity in terms of voltage and frequency), reliability of supply (continuity of electricity supply) and customer services (handling of customers' inquiries and complaints).

Reliability of supply was the main focus of this chapter because of its importance and the unavailability of data on other aspects of service quality. Reliability of supply was measured using the duration and frequency of interruptions to customers on a system-wide basis.

The data show that there is variation in quality of service across all of the utilities included in this study. This is consistent with significant supply cost differences due to scale economies that have led to different price–quality of service tradeoffs.

Although reliability varies considerably between urban and rural-based utilities, no pattern of variation between Australian and overseas utilities is apparent (see figure 6.1). That said, there are inconsistencies in the way reliability measures are defined. For example, some utilities include interruptions caused by major events such as storms, whereas others exclude them. These differences in calculation of the indexes may have a significant impact on the apparent reliability performance of a utility if, for example, a large proportion of its network is in areas that are prone to severe weather.

The apparent absence of a systematic difference in quality of service (as measured by reliability) suggest that it is unlikely then that overseas utilities with similar supply areas possess a systematic cost advantage due to inferior quality of service. However, the overall variation in quality of service underlines the importance of adjusting for differences in quality of service costs if the relative performance of urban and rural-based utilities is to be inferred from prices.

The expenditure required for incremental improvements to reliability of supply appears to be small compared with the cost of supply. As indicated in the previous section, the cost of SAIDI improvement estimated by the ORG(Vic) and their consultants was about $1 million per minute. Similarly, Energy Australia published a figure of $1.8 million per minute for its high priority, low cost reliability improvement projects. Expenditure on the full five year reliability program, would add approximately 0.13 cents per kWh to electricity prices.

It is likely that quality of service preferences are also being met. Surveys conducted by utilities revealed that customers are willing to pay only small amounts for improvements in supply quality and reliability. This suggests, in Australia at least, that the scope for service quality improving investment is limited.

Cost outcomes to consumers due to departures from an efficient quality of service–price tradeoff are likely to be minor. Surveys reveal that consumers are not prepared to pay significantly more for improvements to quality of service.

Quality of service is to some extent a legacy of history and hence largely outside the control of current managers. Only incremental changes are likely to be possible in the short-run, with minor consequences for prices. Nevertheless, comparisons of performance between urban and rural-based utilities should only be undertaken on the basis of prices adjusted for the different costs associated with their quality of service differences.

7 Cost factors outside the control of industry

As outlined in chapter 2, there are factors outside the control of industry that affect the cost of supplying electricity. These factors must be taken into account before the unadjusted prices presented in chapters 3, 4 and 5 can be used as indications of relative efficiency.

A consultant, UMS Group, was engaged to collect cost driver information and associated cost data from the selected utilities included in this study. Some of the utilities approached either did not have the resources available to assist in the data collection, or could see no benefit from participating in this study.

With the data made available, it was possible to provide only an indication of the likely cost impact of these factors. Consequently, the analysis should not be viewed as providing definitive conclusions on the influence of the cost factors upon prices.

7.1 Methodology

The factors chosen for analysis were identified following discussions with industry representatives, with input from UMS Group and their industry contacts. The factors discussed in this chapter are those believed to have the most significant impact upon costs.

Only factors considered to have a direct impact upon costs were considered. Government interventions that have an indirect influence by affecting internal factors, for example, the productive efficiency effects of competition policy, were not examined. See chapter 2 for a discussion of indirect factors.

Information was gathered from each of the studied utilities, using a questionnaire developed by UMS Group in consultation with the Commission. In the main, operational and financial data were requested. For some factors, however, the participating utilities were asked to quantify or estimate their likely contribution to costs.

Cost structures were used to gauge the influence of factors affecting one part of the industry on overall costs. To this end, the industry was disaggregated into its component sectors — generation, transmission, distribution and retail— as appropriate, to analyse the influence of a particular factor upon each sector of the industry.

The information was collected and analysed on a comparative static basis. That is, the contribution of each factor upon relative costs was quantified holding all other cost factors constant. A factor that produces a response, for example, capital investment, can affect other costs. Nevertheless, this approach is a systematic way of examining the costs of external factors that provide a general indication of the effect on overall costs.

To protect commercially-sensitive information provided by the utilities, only publicly-available information on the cost drivers underlying each factor is presented. For example, the number of customers per square kilometre, the principal cost driver of economies of customer density, was reported for each utility, but not the details of the underlying cost structures.

Cost comparisons were conducted on a cents per kWh basis, rather than using the units of the cost driver that may be more reasonable in engineering terms. The aim of this was to provide a common unit of comparison across the factors so that the influence of each factor, relative to the others, could be assessed.

A criterion of significance was developed as an indication of a factor's likely significance in explaining the price outcomes observed in chapters 3, 4 and 5 (see table 7.1). For example, if the cost of a factor varied by less than 1 cent per kWh between the utilities, it was considered that this factor would explain only a small proportion of the differences in observed prices.

Table 7.1 **Criteria of significance of each factor in explaining price outcomes**

Significance of factor in explaining price outcomes	*Difference in cost between utilities*
	cents per kWh
Small	<1
Moderate	1–3
Large	>3

The data collected are for the financial year January 1999 to December 1999 for the overseas utilities, and July 1999 to June 2000 for the Australian based utilities. All costs were converted to Australian dollars using the purchasing power parities listed in chapter 3.

7.2 Generation

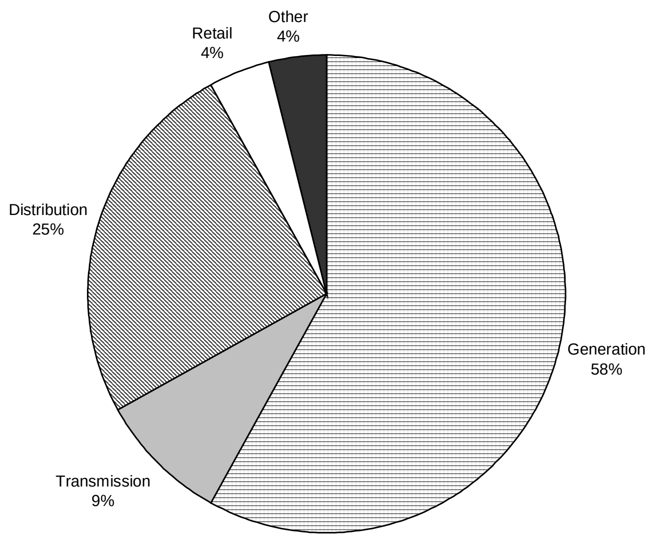
Indicative estimates of industry cost structures provided by UMS Group indicate that generation costs account for around 60 per cent of total costs in the industry (see figure 7.1). This suggests that differences in generation costs between the studied utilities can have significant implications for the price comparisons in chapters 3, 4 and 5.

It should be noted that industry cost structures may vary across countries, and between rural-based and urban-based utilities. For example, generation costs account for around 63 per cent of Western Power's total costs. The overseas utilities indicated that generation costs ranged between 48 and 65 per cent of total costs.

The operation of the wholesale market may also affect the flow-through of differences in generation costs to final prices. Where the marginal generator sets the pool price, cost reductions achieved by base-load generators may not be reflected in final prices. See chapter 2 for a further discussion of the operation of the wholesale market and the role of generators.

The major drivers of generation costs are the delivered costs of fuel and water, the holding of reserve plant to ensure reliability, the age of plant and environmental requirements.

Figure 7.1 **Indicative composition of industry costs, per cent, 2000**



Data source: UMS Group (2001).

Delivered cost of fuel

Coal is the principal type of fuel used in the generation of the electricity supplied by the utilities included in this study. The price that generators pay for coal is influenced by the quality of the coal (see box 7.1) and transportation costs.

Box 7.1 **The quality and value of coal**

The quality of coal is determined by its properties. The properties that are of greatest concern to operators include calorific value, ash content, sulphur content, moisture content, grindability and volatile matter content.

Generally, the value of coal increases as its calorific value and grindability increases. A high calorific value means that less coal is required to fire a generation unit for a given period of time than a coal with low calorific value. Also, the more grindable is coal, the lower are the capital and operating costs associated with preparing the coal for use.

The value of coal will also increase as the ash, sulphur, moisture and volatile matter content of the coal decreases. This is because it reduces the capital and operating costs associated with the installation and operation of specialist equipment, such as scrubbers and handling systems, designed to handle problems with constituent materials.

For example, the ash produced from burning coal creates fouling problems. Coal with greater fouling tendencies requires more expensive capital investment in a power station, both to handle the fouling and to offset the reduction in plant availability due to fouling.

Different types of coal possess these range of properties in different proportions. For example, brown coal is considered inferior in quality compared with black coal, primarily because it contains a relatively high level of moisture. The poor quality of brown coal means that boilers must be about twice the volume of black coal boilers, and are thus about 60 per cent more expensive.

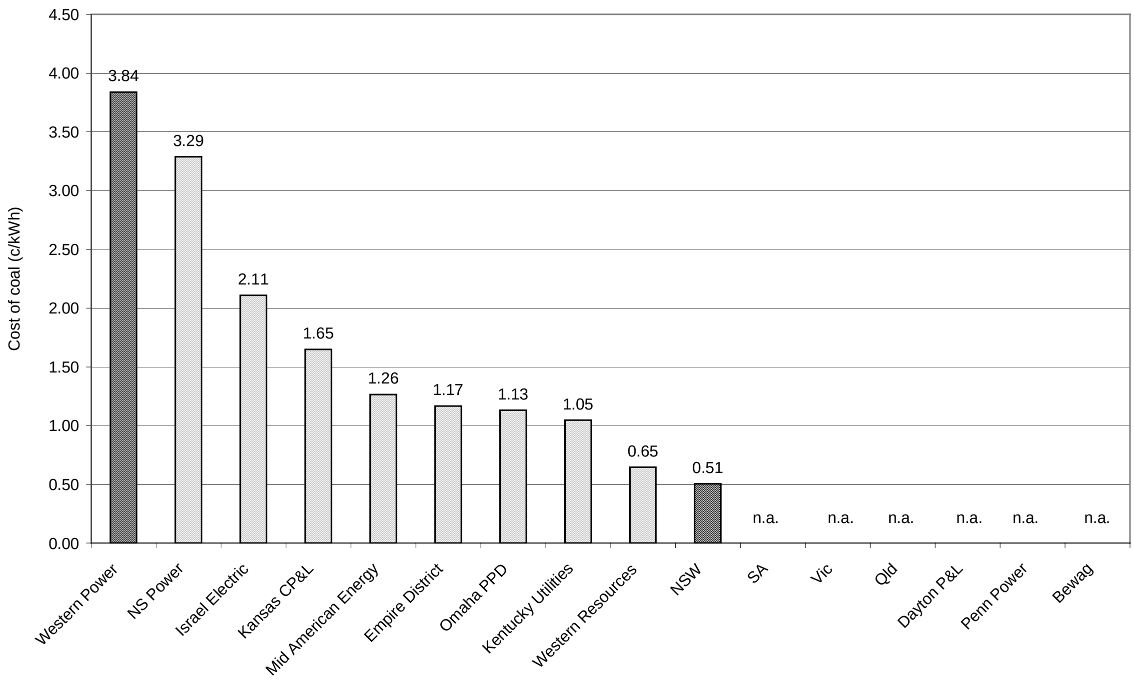
Sources: IEA (1997); Victorian Brown Coal Council (1983).

Information on the delivered cost of coal was only available for some of the generators supplying the utilities (see figure 7.2, the Australian utilities are shaded black). Coal costs for these utilities ranged between 0.51 and 3.84 cents per kWh. This suggests that differences in the delivered cost of coal may be a significant explanator of the price outcomes observed in chapters 3, 4 and 5.

These estimates are derived from the total cost of coal delivered to the generation facilities of each utility. The total annual cost of coal input is divided by the quantity of electricity generated from coal to derive a unit cost estimate.

The estimates include any purchasing and transportation costs, but exclude the costs associated with processing the coal in preparation for use.[1]

Figure 7.2 **Delivered cost of coal, Australian dollars, 1998 and 2000**



Note Prices are converted to Australian dollars using the purchasing power parities listed in table 3.2.

Data sources: Data provided by utilities; EIA(US) (1999b); IPART (2000).

Delivered cost of water

Water is used in coal-fired generators for steam condensing. The cost to generators of acquiring an adequate and reliable source of water depends upon its quality, the quantity required and the cost of transporting it to the generation facility. Each of these factors determines the type and quantity of infrastructure needed to maintain an adequate supply of water.

Poor water quality increases capital and operating costs because of the possibility that impurities in the water may cause corrosion, scaling and fouling problems. For example, turbines may lose efficiency because of silica build-up on turbine blades.

1 Transport costs are likely to vary between the studied utilities because of the haulage distances involved. In some cases, utilities have their own coal mining operations and only incur the cost of conveying it to the generator. In other cases, utilities pay a higher transport cost.

As water quantity requirements and the distance between the source and the generation facility increase, the capital and operating costs of the infrastructure (such as dams, pipelines and pumps) required to ensure a supply of water also increase. For example, larger dams may have to be constructed and maintained as the quantity of water demanded increases.

Estimates of the likely cost impact of the delivered cost of water were unavailable.

Economies of massed reserves

Economies of massed reserves arise when it costs proportionally less to maintain the capacity required to meet peak demand and allow for equipment failure when there are a large number of interconnected generation units.

To ensure reliability of supply, an electric power system must hold a certain quantity of generation plant in reserve in order to cover for unplanned generation unit failures or unexpectedly high demand peaks. These reserves are in addition to capacity held to meet expected peak demand.

In Australia, reserve plant is shared among the member States of the Australian National Electricity Market. To some extent, South Australia’s reserves are supplemented by reserves in Victoria, and ultimately New South Wales. However, the extent to which reserves can be shared is constrained by the capacity of the interconnectors between the States.

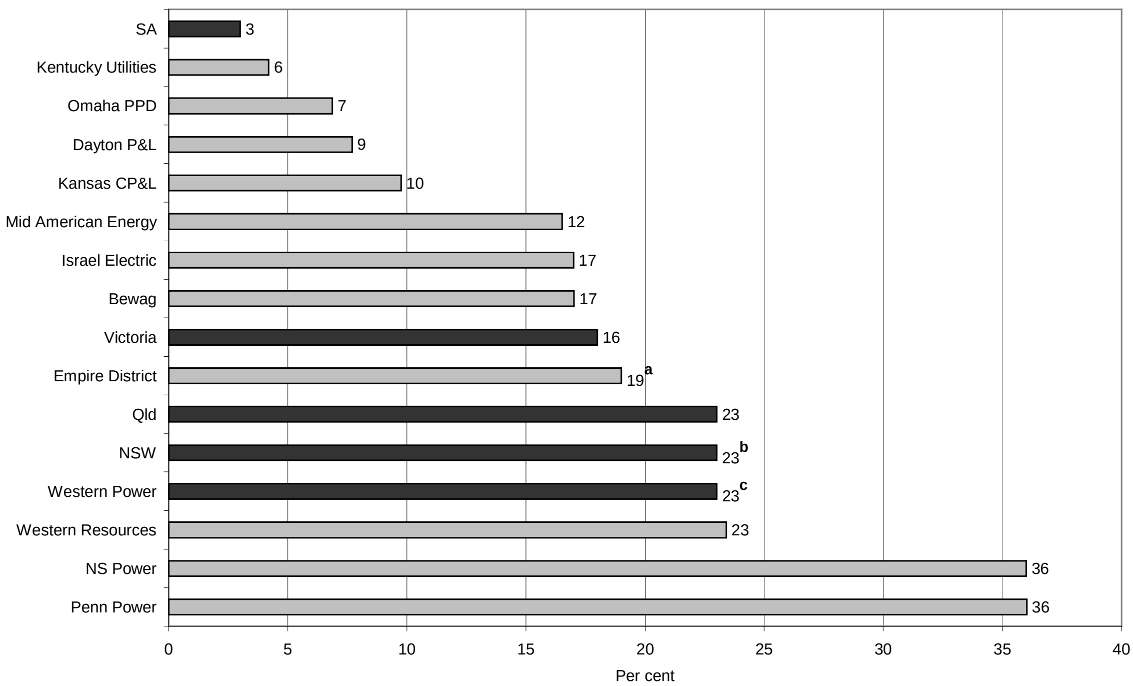
With the exception of Israel Electric, each of the overseas utilities is interconnected with larger systems. For example, NS Power is interconnected with the Northeast Power Coordinating Council which includes the States of New York, six New England States and the provinces of Ontario, Quebec and New Brunswick. Similarly, Bewag is interconnected with the German and, even larger, European electricity systems.

Kapoor and Mazumdar (1996) demonstrated how the level of reserves necessary to meet an expected mean energy demand would vary as the number of generation units attached to a system increased. For a 3-unit system (combined capacity of 54MW), reserves needed to be around 6.3 per cent higher than the expected mean energy demand to ensure a 95 per cent chance of meeting that demand. For a 32-unit system (combined capacity of 11 900MW), the required reserve fell to 1.66 per cent.

Massed reserves are interrelated with the investment cycle. The reserve plant margin will increase where the decision is taken to build new generation capacity to meet future demand growth.

Empirical analysis of the influence upon costs of holding reserve plant is unavailable. However, it is expected that, for a given level of interconnection with other systems, the larger the number of generating units available within a system, the lower is the reserve plant required by individual generators, and thus the lower are costs to each generator. As interconnection with other systems increases and larger amounts of energy can be sourced from more units, the reserve required by individual generators, and the associated costs incurred, decreases further.

Figure 7.3 **Reserve plant margin, per cent of system peak, 1999 and 2000**



Note Reserve plant margins exclude reserve plant available through interconnections with other systems. Reserve plant margin is calculated as installed capacity minus system peak demand divided by the system peak demand. **a** Includes capacity purchased to meet customer requirements. **b** ACTEW is supplied by the NSW power system. **c** Western Power is supplier of last resort for independent power producers. This calculation includes Western Power demand only.

Data sources: Data provided by utilities; Bewag (1999); Dayton P&L (2000); Empire District Electric Company (2000); ESAA (2000b); First Energy Corporation (2000); Kansas CP&L (2000); Western Resources (2000); LG&E Energy Corporation (2000); Mid American Holdings Company (2000); NS Power (2000); Omaha PPD (2000).

The results of rank correlations (using Spearman's technique[2]) conducted on reserve plant margin and the average prices per kWh reported in chapters 3, 4 and 5

2 Spearman's technique calculates a rank correlation coefficient from the absolute differences in the ranks of a collection of individuals or characteristics (in this case, utilities) (Gujarati 1988). The coefficient can be used to determine whether there is a negative, positive or no relationship between the ranked individuals or characteristics.

showed positive and significant relationships for only some of the large business bundles. The calculated correlation coefficients indicated that there was only a weak to moderate positive relationship (0.01 to 0.45) between the two variables for each residential, small to medium and large business consumption bundle.

In the absence of more comprehensive data, an estimate of the annual value of generation assets held in reserve is provided as a proxy of the likely cost impact of holding reserve plant margin (see figure 7.4).

The annual value of reserves was calculated by multiplying the value of plant and equipment (see box 7.2 for a discussion of asset values in the US) by the reserve plant margin and the annual rate of depreciation plus an assumed weighted average cost of capital. This was then divided by the quantity of electricity generated to convert it to cents per kWh.

Box 7.2 **Asset valuations in the US**

In line with US accounting standards, the value of utility plant is recorded at historical cost of construction or acquisition. Construction costs include labour, materials and taxes. They also include an allowance for funds used during construction (the net cost for the period of construction of borrowed funds and a reasonable return for other funds used for construction purposes).

Assets are depreciated on a straight line basis over the estimated life. Depreciation rates for a number of the studied utilities averaged between 3 and 4 per cent in recent years. The cost of plant retired plus any net cost of removal is generally charged to accumulated depreciation.

It is difficult to determine the extent to which utility plant has been retired in the US. However, all the studied utilities incur depreciation and amortisation expenses. As an example, Kentucky Utilities' depreciation and amortisation expenses accounted for 10 per cent of company expenses in 1999.

In 1999-2000, most of the studied utilities were undertaking construction, including investment in new peaking plant.

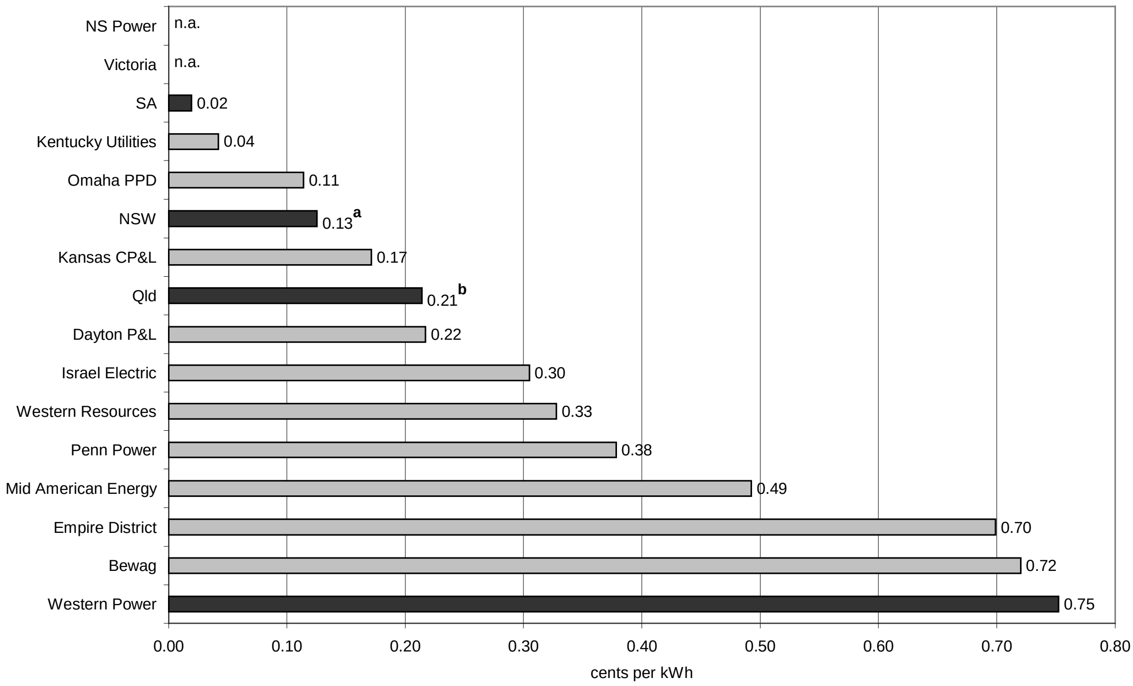
Source: Various utility annual reports.

The values in figure 7.4 may overstate the cost of the reserve required for efficient operation, as not all the cost may be outside the control of the generators in the short-run.

There was a wide dispersion in the value of generation assets held in reserve. However, the size of the cost estimates suggest that the costs of holding reserve plant are unlikely to be a major explanator of the price differences.

These data should not be used to draw strong conclusions about a particular utility's performance in terms of the cost of holding reserve plant margin. These data are only estimates of the likely cost impact of holding reserve plant and, therefore, only provide a suggestion of how the need to hold reserves may affect costs.

Figure 7.4 **Value of generation assets held in reserve, annualised, Australian dollars, 1999 and 2000**



n.a. Not available. **Note** The annual value of reserves was calculated by multiplying the value of plant and equipment by the reserve plant margin and the annual rate of depreciation plus an assumed weighted average cost of capital. This was then divided by the quantity of electricity generated to convert it to cents per kWh. Rates of depreciation ranged between 3 and 5 per cent, while a 7 per cent weighted average cost of capital was assumed. Asset values were converted to Australian dollars using the purchasing power parity exchange rates listed in table 3.2. **a** May under-estimate the value of reserve plant as figure is based upon the combined value of reserve plant for Macquarie Generation and Delta Electricity. The value of power station buildings, plant and equipment held by Pacific Power and Sithe Energies was unavailable. **b** May under-estimate the value of reserve as the estimate is based upon the combined value of reserve plant for CSEnergy, Stanwell Corporation and Tarong Energy Corporation. The value of generation assets held by Origin Energy and Qld Power Trading Company were unavailable.

Data sources: Data provided by utilities; Bewag (1999); CSEnergy (2000); Dayton P&L (2000); Delta Electricity (2000); Empire District Electric Company (2000); ESAA (2000b); First Energy Corporation (2000); Kansas CP&L (2000); Western Resources (2000); LG&E Energy Corporation (2000); Macquarie Generation (2000); Mid American Holdings Company (2000); Omaha PPD (2000); Stanwell Corporation (2000); Tarong Energy Corporation (2000).

Age of generation plant

The age of plant affects the capital and operating costs of a utility. Capital costs can be reduced by extending the useful life of generation plant, thus lowering depreciation expenses and avoiding the costs associated with building new plant. However, as plant ages, its operating efficiency declines and fuel and maintenance costs increase.

The age of generation plant in Australia is similar to that used by the overseas utilities (see table 7.2). Although this suggests that the age of plant is unlikely to result in significant cost differences between the utilities, variations in the methods used for valuing and depreciating assets can affect the accounting expenses reported by utilities. Accounting methods that under-value assets and thus reduce accounting expenses allow utilities to earn normal rates of returns with low prices. In the long-run, prices must reflect actual costs if utilities are to remain financially viable, without compromising quality of service and efficient investment.

Table 7.2 **Age of generation plant, largest plant by capacity, 1999**

	Name of largest plant	*Age of largest plant*
		Years
Overseas utilities		
Bewag	n.a.	n.a.
Dayton P&L	Killen Station	17
Empire District	Asbury	29
Israel Electric	Orot Rabin	11
Kansas CP&L	La Cygne	26
Kentucky Utilities	Ghent	25
Mid American Energy	Neal North	16
NS Power	Lingan	approx. 20
Omaha PPD	Nebraska City	20
Penn Power	Beaver Valley, Unit 1	23
Western Resources	Gordon Evans EC	32
Australian utilities		
Western Power, WA	Kwinana A&C	23–29
CS Energy, Qld	Swanbank	approx. 26–33
Macquarie Generation, NSW	Bayswater	approx. 15
Tarong Energy, Qld	Tarong Power Station	approx. 13
Yallorn, Vic	Western Power Station	approx. 18
Delta Electricity, NSW	Vales Point	approx. 20
Loy Yang, Vic	Loy Yang	approx. 20
NRG Flinders, SA	Northern Power Station	approx. 15

n.a. Not available.

Source: EIA (1999c); Israel Electric (1998); Various utility websites.

Environmental regulation

The environmental issues associated with the electricity industry centred on the discharge by generators of waste into the air and water, and the effect that their activities may have had on land use, particularly in regard to solid wastes and coal mining.

Environmental regulation is often the primary method used by governments to limit the environmental impact of electricity industry operations. These regulations include emission limits and other regulations that cause environmental costs to be factored into fuel and other input costs.

Emission limits

Air emission limits seek to place a cap on the quantity of certain by-products that can be discharged into the environment in the process of generating and distributing electricity. They often impose costs because utilities incur costs in installing and operating equipment designed to reduce emissions to required levels. Generally, abatement costs increase with the stringency (lowering) of emission limits.

Air emissions attributable to power generation are:

- *air pollutants*: sulphur dioxide, nitrogen oxides, particulate matter and heavy metals, particularly lead; and
- *greenhouse gases*: including carbon dioxide, methane and chloroflourocarbons.

While the electricity industry is not a producer of methane itself, coal-fired power production indirectly contributes to methane levels as methane is produced from coal mining activities.

Emission limits are not regulated on a consistent basis across countries. They vary in terms of scope, measurement basis and time period. For example, US emission limits are based on concentration levels (parts per million by volume) over either a 1-hour, 8-hour or annual time period. In Victoria, emission limits are set on the basis of emission rate per minute (grams per minute).

These inconsistencies make it difficult to compare the stringency of emission limits across countries. Generator volume flow rates, which allow the conversion of concentration limits to emission rates, were unavailable.

Estimates of the likely cost impacts of differences in the stringency of emission limits were also unavailable.

Other environmental regulations

There may be a range of other environmental regulations, for example government requirements on the placement of power lines, that cause environmental costs to be factored into fuel and other input costs. However, information on these regulations is unavailable.

Summary

Differences in the costs of generation between the utilities studied have implications for the price comparisons because of the significance that generation costs have for overall industry costs.

Using the criteria presented in table 7.1, it is likely that differences in the delivered cost of fuel could be a large explanator of the price differences observed in chapters 3, 4 and 5 (table 7.3).

The cost of water and the cost implications of meeting emission limits may also have consequences for costs. However, the unavailability of data means that it is not possible to gauge the significance of these factors.

Table 7.3 **Likely significance of generation factors**

Factor	*Indicative impact upon costs*[a]	*Likely significance as explanator of price difference*
	cents per kWh	
Delivered cost of fuel	0.510–3.840	large
Delivered cost of water	unavailable	
Economies of massed reserves	0.020–0.630	small
Age of generation plant		small
Environmental regulation	unavailable	

[a] The range in total costs incurred by the utilities from each factor.

Source: PC estimates.

7.3 Transmission and distribution

The contribution of transmission costs to overall industry costs is small relative to generation and distribution costs. They account for only around 9 per cent of total industry costs (see figure 7.1), although this may vary between countries, and between rural-based and urban-based utilities.

The small size of transmission costs within the overall cost structure of the industry suggests that differences in the costs of transmission between the utilities are unlikely to be a significant explanator of differences in the price outcomes observed in chapters 3, 4 and 5.

The most significant drivers of transmission costs are natural disasters, terrain and climate and customer demand characteristics. These factors are discussed in section 7.6.

Of greater significance to overall industry costs are distribution costs. Indicative estimates provided by UMS Group suggest that distribution costs represent around 25 per cent of overall costs of the industry (see figure 7.1). Although not as significant as the costs of generation, their share of overall costs suggests that differences in distribution costs between utilities could be a significant explanator of the price outcomes.

The major drivers of distribution costs considered in this study include:

- airborne pollution;
- vegetation growth and management;
- requirements to bury cable;
- contributed assets;
- production economies; and
- energy losses.

Airborne pollution

Overhead lines exposed to airborne pollution, such as salt air or industrial pollution, are more likely to experience flashover and fire due to the build up of contaminants on insulators causing electrical discharge tracking. Overhead line insulators must therefore be washed regularly, increasing operating costs, or special insulators must be installed at a higher capital cost.

Information on whether airborne pollution affected the systems of the studied utilities was available for Israel Electric, NS Power, Energy Australia, ETSA Utilities, Western Power and Western Resources (see table 7.4). However, only three of these utilities provided an estimate of the likely cost impact. These estimates ranged between 0.003 cents per kWh and 0.098 cents per kWh. The size of these estimates suggests that airborne pollution is unlikely to be a major explanator of differences in the price outcomes observed in chapters 3, 4 and 5.

Table 7.4 **Susceptibility to airborne pollution, 1999 and 2000**

Utility	*Susceptible*
Israel Electric	yes
NS Power	yes
Energy Australia	no
ETSA Utilities	yes
Western Power	yes
Western Resources	no

Source: Data provided by utilities.

Vegetation growth and management

The costs of vegetation management are driven by the density of trees and the growth rate of trees under or near overhead lines. Both factors increase operating costs because tree density determines the number of trees that need to be trimmed per route kilometre of overhead line, and growth rate determines the frequency of trimming required to maintain acceptable clearances.

Other factors that may increase vegetation management costs by increasing the need for more frequent trimming are:

- *voltage* — higher voltages require greater clearance space;
- *line clearance to ground* — the lower the clearance the less distance for vegetation to bridge;
- *environmental sensitivity of the local community*; and
- *easement standards* — affecting accessibility for maintenance crews.

Of the utilities studied, Israel Electric, NS Power, Energy Australia, ETSA Utilities, Western Power, Energex and Western Resources provided information on vegetation management (see table 7.5).

These utilities experienced varying rates of vegetation growth and average tree density. ETSA Utilities and Western Power have a slightly higher proportion of faster growing trees, suggesting that both utilities may incur slightly higher maintenance costs than NS Power and Israel Electric. Tree density was similar across the utilities, except NS Power which had a heavy tree density in its service territory.

Table 7.5 **Vegetation growth and management, per cent, 1999 and 2000**

Utility	*Tree growth*		*Tree density*				*Proportion of system affected*
	Slow growth[a]	*Fast growth*[a]	*Light*[b]	*Medium*[b]	*Heavy*[b]	*Very heavy*[b]	
	per cent	per cent	per cent	per cent	per cent	per cent	per cent
Israel Electric	60	40	30	60	10	0	65
NS Power	100	0	5	15	75	5	85
Energy Australia	n.a.	n.a.	20	36	24	20	n.a.
ETSA Utilities	50	50	40	30	20	10	70
Western Power	20	80	80	10	5	5	80
Energex	10	90	10	10	40	40	80
Western Resources	40	60	10	40	40	10	50

n.a. Not available. **a** Slow growth = <76.2cm per year vertical growth; fast growth = >76.2cm per year vertical growth. **b** Explanation of categories: Light = Fewer than 35 trees per mile (21.7 trees per kilometre), or 0-25 per cent of line requiring clearing; Medium = Between 35 and 70 trees per mile (21.8 and 43.5 trees per kilometre), or 25-50 per cent of line requiring clearing; Heavy = Between 71 and 140 trees per mile (44.2 and 87 trees per kilometre), or 51-75 per cent of line requiring clearing; Very Heavy = Greater than 140 trees per mile (87 trees per kilometre), or 76-100 per cent of line requiring clearing.

Source: Data provided by utilities; Empire District (2000).

The cost estimates of managing vegetation growth ranged between 0.03 cents per kWh and 0.09 cents per kWh. These estimates were derived by dividing the estimated cost of managing vegetation provided by each of the utilities by the quantity of electricity each utility generated.

It is difficult to draw a conclusion on whether vegetation management costs are higher in Australia than overseas because of the lack of comparable data. However, the size of these estimates suggests that vegetation management is unlikely to be a major explanator of differences in the price outcomes observed in chapters 3, 4 and 5.

Requirement to bury cables

Some of the utilities were required by government to place some of their cabling underground (see table 7.6). Underground cabling imposes large capital costs because of the cost of trenching, particularly in built-up areas where under-pavement boring is required (see box 7.3).

Table 7.6 **Requirements to bury cables, 1999 and 2000**

Utility	*Government requirement to bury cables?*	*Length required to be buried*	*Proportion of total line length*
		km	per cent
Israel Electric	yes	500[a]	1.3
NS Power	yes	20	0.1
Energy Australia	yes	n.a.	n.a.
ETSA Utilities	yes	524	0.7
Western Power	yes	7 684[b]	8.0
Energex	yes	n.a.	n.a.
Western Resources	yes	n.a.	n.a.

n.a. Not available. [a] 1999 data. [b] Figure represents 90 per cent of Western Power's underground cabling.

Source: Data provided by utilities.

However, despite the higher capital costs involved, there are potential benefits from installing cables underground. These include:

- Reductions in maintenance costs. There are also fewer outages resulting from motor vehicle collisions with poles or climatic conditions. However, should an outage occur, its duration may be longer because of the potential need to excavate cables for repair;
- Reductions in preventative and reactive maintenance costs;
- Reduced tree trimming costs; and
- Lower transmission losses as the cross-sectional area of an underground cable is usually larger than its overhead equivalent. Lower transmission losses also results in a reduction in greenhouse gas emissions.

From information supplied by two of the utilities studied, the estimated cost of having to bury cables ranged between 0.01 and 0.09 cents per kWh. These estimates were calculated by totalling the capital and operating costs associated with the length of low voltage and distribution cable required to be buried, and dividing by the quantity of electricity generated.

Box 7.3 **Underground cabling systems and their impact upon costs**

The costs of underground cabling varies with the type of cabling design and the voltage of cable used.

Cabling design

Direct buried ring-main underground cable systems have very low maintenance needs, requiring switchgear inspections on an infrequent basis. By contrast, *closed* ring underground cable systems have relatively high capital and operating costs due to the requirement to install unit protection equipment and to maintain indoor switchgear and control equipment.

Voltage

High voltage cables usually sustain higher capital costs per metre than low voltage cables due to the cost of high voltage joints and pad-mounted kiosk substations or indoor substations that are part of the design of the cabling system. Putting high voltage cables underground usually requires the associated distribution substations to be transferred from a pole top to either a pad-mounted kiosk type arrangement or installed indoors. This usually represents a substantial capital cost because pad-mounted transformers and indoor substation facilities are usually more expensive than their pole-top equivalent and land purchases or easements are usually required.

Another reason why high voltage cables are more expensive to install underground is the extra level of insulation and earth screening that is required.

The civil engineering costs associated with installing either type of cable are similar. However, some utilities opt to provide a greater level of mechanical protection over high voltage cables (plastic barriers or concrete slabs) to reduce the likelihood of the cable being pierced by a shovel, crow bar or excavator.

Source: UMS Group (2001).

Contributed assets

Contributed assets are partially or completely funded by the customer but maintained and owned by the electricity utility. Contributed assets represent a significant revenue stream, as electricity utilities can avoid the capital cost associated with network expansion.

Contributed assets affect the level of prices because utilities do not incur a liability to service a debt. Consequently, utilities only have to recover operating costs, which provides scope to lower prices.

Information on the extent of contributed assets held by the utilities was unavailable.

Production economies

Scale economies are inherently interrelated. For example, economies of customer density derived from serving a larger number of customers per length of distribution line are related to the cost savings resulting from economies of size. Further, most distribution utilities are integrated to some extent into larger power systems and thus capture some system-level economies of scale (Joskow and Schmalensee 1985).

Production economies are also interrelated with distribution losses. For example, utilities with higher customer densities are likely to have lower distribution losses because of the smaller length of line over which the electricity travels.

Available data were used to indicate whether cost economies may be more significant in Australia or in the overseas countries. Where possible, some indication of the impact on costs, and hence prices is presented.

Economies of output density

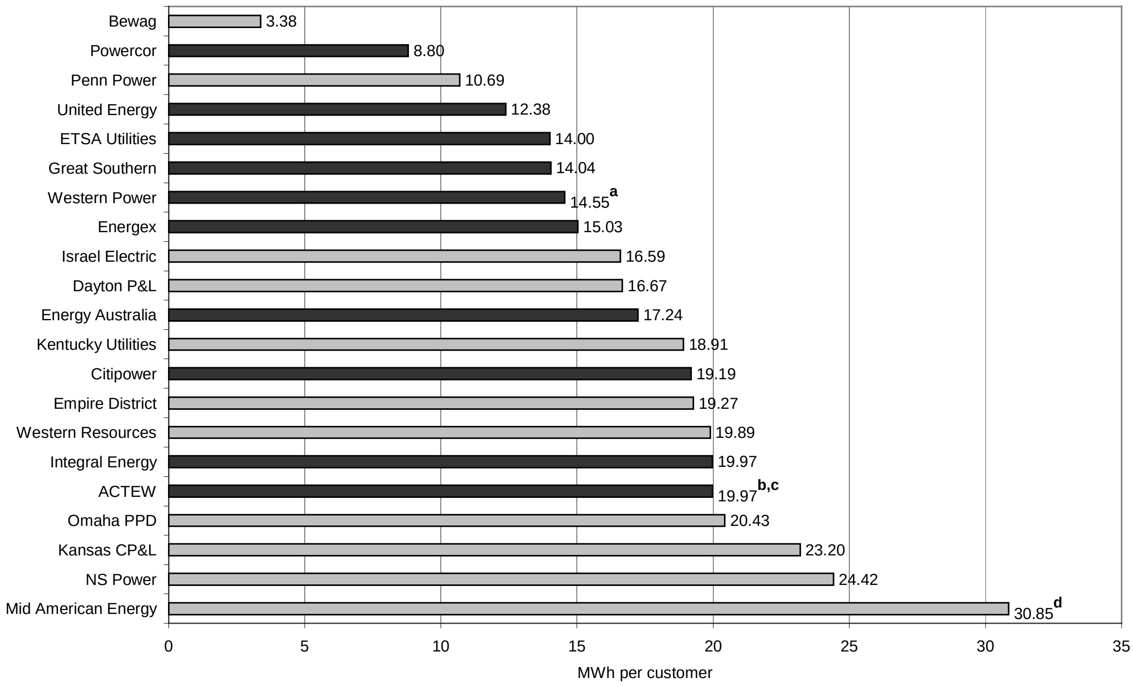
Economies of output density exist where unit costs decline with an increase in output, holding the size of the service area and the number of customers fixed. The key cost driver is average consumption per customer. When average consumption increases in a particular geographic area served by a distribution system, if fixed costs are not commensurately affected, unit costs decline.

Average consumption per customer for the utilities studied is presented in figure 7.5 (Australian utilities are shaded black). These data were derived, where possible, by dividing the quantity of electricity sold through the distribution and low voltage network by the number of distribution and low voltage customers. In some cases, the number of residential and commercial customers or the total number of customers and sales to these customer classes has to be used because of the unavailability of data.

The results of the empirical work, conducted at the distribution level, indicate that economies of output density are significant. Estimates of economies of output density — the percentage change in costs associated with a one per cent change in density — range between -1.2 and -4.6 (Thomson 1997; Filippini 1998; Fillipini and Wild 2000).

These estimates should not be used to draw conclusions about the likely cost impact of variations in the average consumption per customer data in figure 7.5. First, in the absence of better quality data, the data in figure 7.5 provide only an estimate of output densities. Second, the econometric estimates relate to overseas utilities that are mainly located in urban areas. Third, elasticities are point estimates that cannot be used to infer the extent of economies over a large range of output densities. Further, the utilities that form the basis of the estimates may have different cost structures to the utilities included in this study.

Figure 7.5 **Output densities, average annual consumption per customer, 1999 and 2000**



[a] South-Western Interconnected System only. [b] 1996-97 data. More recent data was unavailable. [c] Only includes the number of residents and sales to residents. More comprehensive data was unavailable. [d] Based upon the total number of customers in Iowa and the percentage of electricity generated sold to Iowa.

Data sources: Data provided by utilities; Bewag (1999); Dayton P&L (2000); Empire District Electric Company (2000); EIA (1999a); ESAA, pers. comm. 30 May 2001; First Energy Corporation (2000); Kansas CP&L (2000); Western Resources (2000); Mid American Energy Company (2001); Omaha PPD (2000); SCNPMGTE (1998).

Nevertheless, the econometric estimates suggest that a lower average consumption per customer may have a large effect upon production costs. Hence, the data in figure 7.5 suggest that at least some of the Australian utilities may be at a disadvantage in terms of economies of output density.

To test this, rank correlations were performed on the rankings of the utilities in figure 7.5 and the utility rankings resulting from the price outcomes in chapters 3, 4 and 5. For all but one of the consumption bundles, a significant negative relationship was observed, suggesting that a utility with a lower output density also had higher average prices.

To further test the relationship between prices and output density, a correlation coefficient was calculated. Correlation coefficients measure the strength of association between two variables — in this case, average prices per kWh and output density.

The results indicate that there is a moderate to strong negative relationship (-0.32 to -0.63) between the price outcomes observed in chapters 3, 4 and 5 and each utility's output density. As for the rank correlation results, the relationship was strongest for the small to medium business and large business bundles.

Economies of customer density

Economies of customer density exist if unit costs decrease with an equi-proportional increase in output and customer numbers, holding the size of the service area fixed.

Existing empirical work analyses economies of customer density in terms of customers per square kilometre of service territory. The results indicate that economies of customer density are significant — average costs fall the more densely populated is a utility's service territory — and range between -1.0 and -1.6 (Thomson 1997; Filippini 1998; Fillipini and Wild 2000).

In terms of customers per square kilometre of service territory, customer densities among the utilities studied are diverse (see table 7.7, the Australian utilities are in bold font). For similar reasons as those cited under economies of output density, these data should not be used to draw conclusions about the likely cost impact of variations in the customer densities.

However, the data suggest that some of the Australian utilities, particularly the rural-based ones, may incur higher costs in servicing their territory than the other utilities.

Using square kilometres of service territory may under-estimate customer densities in instances where a utility's franchise area includes large unpopulated, and thus unserviced areas. This would most likely be the case where the utility operates in rural areas. For example, rural customers can often be located along roads.

If the reporting units used are large, estimated densities tend to be lower than the value obtained if smaller reporting areas are used. Consequently, it is important to ensure that the units used are consistent across utilities. If they are not, then systematic errors can be introduced in any analysis based on population density (Cribbett 2000).

Table 7.7 **Customer densities, customers per square kilometre of service territory, 1999 and 2000**

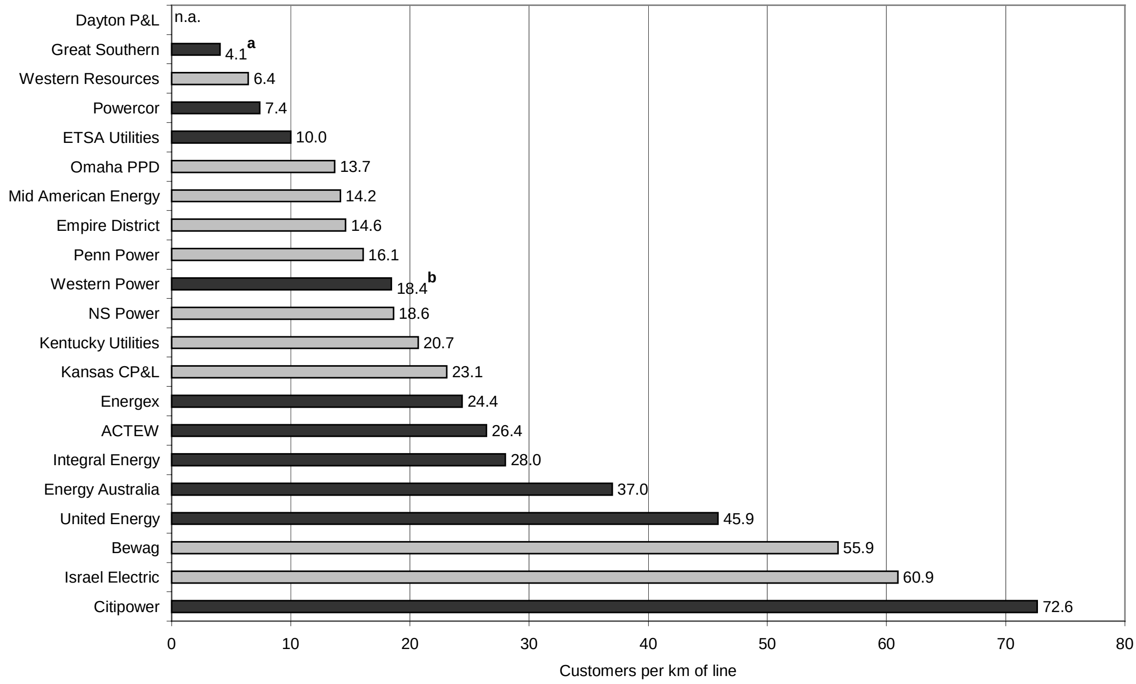
Utility	*Customer density*[a]
	customers per km^2
Bewag	2 418[b]
Citipower	**973**
United Energy	**383**
Israel Electric	96
Energy Australia	**64**
ACTEW	**57**
Energex	**39**[c]
Kansas CP&L	38
Penn Power	34
Dayton P&L	32
Integral Energy	**31**
Mid American Energy	24[d]
Omaha PPD	22
Empire District	6
ETSA Utilities	**4**
Powercor	**4**
Western Power	**3**[e]
Great Southern	**1**[c]
NS Power	n.a.
Kentucky Utilities	n.a.
Western Resources	n.a.

n.a. Not available. [a] Customer densities are calculated on the basis of the total number of customers supplied by the utility divided by the utility's total supply area. [b] Total customer numbers are based on the number of customer installations, high voltage contracts, house service boxes and low voltage metres. [c] Total customer numbers are based on 1996-97 data as more recent data was unavailable. [d] Total customer numbers of Mid American's Iowa market only as Iowa represents 89 per cent of Mid American's total sales. [e] Based on the total number of customers and total supply area of the South-western Interconnected System.

Source: Data provided by utilities; ACTEW (2000); AEP (2000); Bewag (1999); Citipower (1999); Dayton P&L (2000); Empire District Electric Company (2000); EIA (1999a); First Energy Corporation (2000); Kansas CP&L (2000); Western Resources (2000); LG&E Energy Corporation (2000); Mid American Energy Company (2001); Omaha PPD (2000); Powercor (2000); SCNPMGTE (1998); United Energy (2001).

Consequently, a more accurate measure of customer densities may be customers per kilometre of distribution line (see figure 7.6). Under this measure, some rural Australian utilities may operate at a disadvantage to other Australian utilities and some overseas utilities.

Figure 7.6 **Customer densities, customers per kilometre of distribution line, 1999 and 2000**



n.a. Not available. **a** Total number of customers for financial year 1996-97 used as more recent data was unavailable. **b** Data is for the South-western Interconnected System.

Data sources: Data provided by utilities; ACTEW (2000); AEP (2000); Bewag (1999); Citipower (1999); Dayton P&L (2000); Empire District Electric Company (2000); EIA (1999a); First Energy Corporation (2000); Kansas CP&L (2000); Western Resources (2000); LG&E Energy Corporation (2000); Mid American Energy Company (2001); Omaha PPD (2000); Powercor (2000); SCNPMGTE (1998); United Energy (2001).

Economies of size

Economies of size exist if unit costs decrease with an equi-proportional increase in output and the number of customers, while output per customer and customers per line kilometre remain fixed. This is equivalent to an expansion of output holding output density and customer density constant (Fillipini and Wild 2000).

Some empirical studies find that increasing the size of a utility has no significant effect on costs, while others record only a slight decline in average costs.

Economies of scope

Economies of scope exist where it is less costly to combine two or more product lines in one firm than to produce them separately. In the electricity industry, economies of scope may be realised through vertical integration, or through multi-retailing of products. Multi-retailing of products is discussed in section 7.5.

Vertical integration can reduce costs in supplying electricity for a number of reasons. First, there is greater potential to coordinate generation activities, particularly investment, with distribution and retailing activities. Second, it may reduce the costs of managing the risks of price volatility inherent in wholesale trading in a pool market. Third, vertical integration may allow a utility to avoid at least some of the transaction costs associated with energy trading.

The extent of vertical integration differs between Australia and the overseas countries included in this study. With the exception of Western Power, the Australian electricity industry has largely been vertically separated into generation, transmission and distribution/retailing businesses. Conversely, all of the overseas utilities studied remain vertically integrated.

This suggests that the overseas utilities studied may gain inherent cost advantages through vertical integration not accessible to most of the Australian utilities.[3] However, a lack of data meant that these cost advantages could not be quantified.

Energy losses

Energy losses occur in the transmission and distribution of electricity (see chapter 2). Losses directly affect supply costs because, the greater the losses across a network, the greater is the amount of generation required to meet end-use demand. Losses tend to be higher on the distribution network, particularly in rural areas, because of the longer length of low voltage wire relative to throughput.

Average Distribution Loss Factors (DLFs) measure the loss of energy across a distribution network, usually comprising the subtransmission, distribution and low voltage wires. DLFs are used to convert the quantity of energy metered into an equivalent measure of energy passing through the distribution network, including losses.

The DLFs for the utilities studied are shown in table 7.8 (the Australian utilities are in bold font). Where possible, the DLFs were calculated on the basis of losses from the subtransmission, distribution and low voltage networks as a proportion of total sales.

[3] Although there may be a loss of economies of scope with vertical separation, other gains are possible, such as increased competition.

Comparisons on the extent of losses in Australia against those experienced overseas cannot be made because DLFs for the overseas utilities were unavailable.

Table 7.8 **Distribution loss factors, 1999 and 2000**

Utility	*Distribution loss factors*[a]
	per cent
Penn Power	n.a.
Mid American Energy	n.a.
Western Resources	n.a.
Dayton P&L	n.a.
Empire District	n.a.
Western Power	**7.94**[b]
Kentucky Utilities	n.a.
Powercor	**6.78**[c]
Integral Energy	**6.56**[d]
NS Power	6.33
ETSA Utilities	**6.32**
Great Southern	**6.30**[d]
Kansas CP&L	n.a.
Energex	**5.50**[d]
United Energy	**5.43**[c]
Energy Australia	**5.22**
ACTEW	**4.80**[d]
Citipower	**4.21**[c]
Israel Electric	3.27[e]
Omaha PPD	n.a.
Bewag	n.a.

n.a. Not available. **a** Distribution loss factors were calculated on the basis of losses from the subtransmission, distribution and low voltage networks as a proportion of total sales. **b** Distribution loss factor includes losses from the transmission network for the South-western Interconnected System. **c** Proposed overall distribution loss factors submitted by the utility to the Victorian Office of the Regulator-General review of distribution loss factors. **d** Distribution losses for the financial year 1996-97. More recent data was unavailable. **e** Combined distribution and low voltage line losses and distribution transformer losses. Losses from the subtransmission network were unavailable.

Sources: Data provided by utilities; ORG(Vic) (2001); SCNPMGTE (1998).

If the price that customers pay for electricity reflects the costs of supply, then it is possible to provide an estimate of the likely cost impact of the DLFs listed in table 7.8 (see table 7.9). These estimates are an approximation only of the likely cost of losses.

Estimates of the possible cost of losses were calculated by multiplying the quantity of electricity lost (according to the DLFs in table 7.8) by the lowest and highest prices paid by residential and small to medium businesses, and then dividing by the volume of total sales.

Table 7.9 **Valuation of distribution loss factors, October 2000**

	Minimum cost	*Maximum cost*
	cents per kWh	cents per kWh
Citipower	0.41	1.10
Energy Australia	0.44	0.86
NS Power	0.48	1.43
Israel Electric	0.49	0.61
United Energy	0.53	1.41
ETSA Utilities[a]	0.60	1.39
Powercor	0.66	1.76
Western Power	0.85	1.72

Note Estimates are calculated by multiplying the quantity of electricity lost (according to the Distribution Loss Factors in table 7.8) by the lowest and highest prices paid by residential and small to medium businesses, and then dividing by the volume of total sales. [a] Calculated using the price outcomes reported in chapter 3, 4 and 5 for AGL(SA).

Source: PC estimates.

Summary

Of the transmission and distribution costs considered, the costs associated with distribution are likely to be most significant in explaining differences in the prices observed in chapters 3, 4 and 5.

Based upon the assessment criteria presented in table 7.1, differences in distribution costs arising from variations in output densities and, to a lesser extent, customer densities are likely to be the most significant explanators of the price differences observed in chapters 3, 4 and 5 (see table 7.10).

Table 7.10 **Likely significance of distribution factors**

Factor	*Indicative impact upon costs*[a]	*Likely significance as explanator of price difference*
	cents per kWh	
Airborne pollution	0.003–0.098	small
Vegetation growth and management	0.030–0.090	small
Requirement to bury cable	0.01-0.09	small
Contributed assets	unavailable	
Customer demand characteristics	unavailable	
Economies of output density	unavailable	large
Economies of customer density	unavailable	moderate (urban) large (rural)
Economies of size	unavailable	none to small
Economies of scope: vertical integration	unavailable	
Energy losses	0.410–1.760	small to moderate

[a] The range in total costs incurred by the utilities from each factor.

Source: PC estimates.

7.4 Retail

A key driver of retail costs is the ability of a utility to realise economies of scope (see section 7.4). Economies of scope may exist where a utility is able to retail multiple outputs, such as electricity and gas. Cost savings arise from the ability of retailers to offer combined metering, billing and customer services.

The retailing of multiple products is common amongst the overseas utilities, but is less common in Australia. However, it is unlikely that the incidence of multi-product retailing will be a major explanator of the price outcomes as the contribution of retailing to overall supply cost is small (4 per cent) (UMS Group 2001) (see table 7.11).

Table 7.11 **Likely significance of retailing factors**

Factor	*Indicative impact upon costs*	*Likely significance as explanator of price difference*
	cents per kWh	
Economies of scope: Multi-product retailing	unavailable	small

Source: PC estimates.

7.5 Other

There are a range of other factors identified that affect costs in each sector of the industry. These include:

- protecting systems from natural disasters;
- terrain, soil conditions and climate;
- customer demand characteristics; and
- a range of government imposts and interventions.

Protection from natural disasters

Electricity systems are often built to withstand natural disasters, such as cyclones and floods, because of the costs involved in reconstructing damaged power stations or downed lines and the essential service nature of electricity.

Generally, the need to protect systems from natural disasters increases capital costs, and thus prices. In the event of cyclones or earthquakes, power stations are constructed with extra strength, requiring thicker reinforced concrete and extra structural bracing in the boiler and turbine house.

Overhead lines used in transmission and distribution systems are designed and constructed to withstand the high wind loadings associated with typhoons and cyclones. This increases the capital cost per kilometre of line because span lengths are reduced by as much as half, and pole footings are often strengthened with bracing.

Other factors that may cause capital and operating costs to rise as a result of protection against natural disasters are:

- longer line lengths as a result of the re-routing of lines so that they avoid flood prone areas;
- additional line inspection and line clearance activities carried out in high fire risk areas; and
- higher insurance and regulatory compliance requirements.

Information on the need to protect systems from natural disasters was available for Israel Electric, NS Power, Energy Australia, ETSA Utilities and Western Power (see table 7.12). However, only one of these utilities provided an estimate of the likely cost impact.

Table 7.12 **Actions taken by utilities to protect against natural disasters, 1999 and 2000**

Utility	*Protection against natural disasters*	*Description of natural disasters*
Israel Electric	No	No special requirements to protect the system against earthquakes. There is an emergency bypass system for 400kV and 161kV lines. During system design, Israel Electric take into account an extraordinary wind that occurs once every 50 years (according to Israeli standards).
NS Power	Yes	High winds, ice loading, salt deposition and lightning
Energy Australia	No	n.a.
ETSA Utilities	No	n.a.
Western Power	Yes	Earthquakes and cyclonic conditions are incorporated in the design specifications. Maintenance regimes are carried out to review system integrity and strength.

n.a. Not applicable.

Sources: Data provided by utilities.

In the absence of cost data from the utilities studied, an analysis of the costs associated with protecting a system from natural disasters cannot be undertaken.

Terrain, soil conditions and climate

An electricity utility's costs are sensitive to the type of terrain, soil conditions and climatic conditions experienced in the utility's service territory.

Terrain and soil conditions

Terrain affects vehicular access to powerlines or easements for the purposes of construction, maintenance and inspection. For example, rough or mountainous terrain increases operating and capital costs due to greater travel times. Further, poor ground conditions may require the use of manual pole carrying and pole erection techniques.

Similarly, vehicular accessibility can be restricted in 'central business district' environments due to heavy traffic, pedestrian conditions and the scarcity of parking. Blocked access to facilities such as substations can also contribute to increased operating costs per unit of work.

Soil conditions affect the capital cost of underground cable and pole installation. For example, it is costly to dig through rocky ground.

Of the utilities studied, Israel Electric, NS Power, Energy Australia, ETSA Utilities, Western Power, Energex and Western Resources provided information on terrain and soil conditions (see table 7.13). However, estimates of the cost impact of the reported terrain and soil conditions were unavailable.

Table 7.13 **Profile of terrain and soil conditions, per cent, 1999 and 2000**

Utility	*Type of terrain*				*Soil conditions*			
	Flat	*Mountain*	*Swamp*	*Other*	*Rocky*	*Normal*	*Swamp*	*Other*
	per cent				per cent			
Israel Electric	35	45	0	20	55	45	0	0
NS Power	90	5	5	0	30	65	5	0
Energy Australia	90	5	5	0	45	50	5	0
ETSA Utilities	93	5	1	1	25	74	1	0
Western Power	98	1	1	0	30	65	5	0
Energex	70	20	5	5	30	60	5	5
Western Resources	100	0	0	0	10	90	0	0

Source: Data provided by utilities.

Climate

The climatic conditions that are most significant in influencing the efficiency of an electricity system are temperature and temperature variation, humidity, winds, rain, snowfall and storms.

High ambient temperatures and relative humidity affect the design and operation of power stations and transmission and distribution systems, and thus affect capital and operating costs.

High ambient temperatures reduce generating unit efficiency because condensor vacuums operate at below optimum level, restricting the performance of low pressure turbines. Consequently, more fuel is consumed in generating a given amount of electricity, increasing the cost of electricity production.

High temperatures also tend to increase the sag of overhead lines. This results in reduced clearances to vegetation, property and infrastructure or to other circuits on the same route. Whilst there may be some cost involved in constructing lines with larger clearances to compensate, these costs are relatively small and are unlikely to significantly impact upon retail prices (UMS Group 2001).

Frequent strong winds can increase outage rates due to overhead lines knocking against each other. In this event, restoration activity must be carried out, contributing to higher operating costs.

Higher operating cost can be avoided by placing lines underground or installing line separators. However, this has the effect of raising capital costs. Additional capital costs may also be incurred if interruptions result in lines being rebuilt or reinsulated, or if line span lengths are reduced or higher strength poles are used.

In cold climates, ice can form on overhead lines causing them to sag. This usually results in higher capital costs as span lengths may be reduced to maintain line clearances. Higher pole strengths may be required, involving additional materials and thus higher capital costs.

Of the utilities studied, Israel Electric, NS Power, Energy Australia, ETSA Utilities, Western Power, Energex and Western Resources provided information on temperature, relative humidity and climate (see tables 7.14 and 7.15). Information on the cost impact of climate was unavailable.

Table 7.14 **Temperatures and relative humidity, 1999 and 2000**

Utility	*Temperatures*						*Relative humidity*				
	Summer			*Winter*							
	Min.	*Ave.*	*Max.*	*Min.*	*Ave.*	*Max.*	*Sum.*	*Aut.*	*Wint.*	*Spr.*	*Yr Ave*
	celsius			celsius			per cent				
Israel Electric	21	27	34	6	13	26	76	77	85	81	80
NS Power	12	16	21	-8	-4	5	71	70	76	71	72
Energy Australia	19	24	35	7	13	20	74	80	70	65	n.a.
ETSA Utilities	16	22	28	8	12	16	54	65	76	68	63
Western Power	16	23	30	9	13	18	47	57	69	49	56
Energex	5	23	41	-2	16	35	71	74	72	64	70
Western Resources	20	26	32	-9	-3	3	58	54	64	55	59

Note Certain utilities are not included because information was not available.

Source: Data provided by utilities.

Table 7.15 **Winds, rainy and snowy days and storms, 1999 and 2000**

Utility	*Winds*		*Rainy/snowy days*				*Storms*	
	Days	*Velocity*[a]	*Days*	*Ave. rainfall*	*Ave. snowfall*	*Area affected*	*Freq.*	*System affected*
	no./yr	km/hr	no.	mm	cm	per cent	no./yr	per cent
Israel Electric	0	144	0	0	0	0	0	0
NS Power	2	90	158	1 178	196	100	3	100
Energy Australia	10	0	130	850	0	5	5	45
ETSA Utilities	30	120	0	0	0	0	10	90
Western Power	25	0	119	869	0	0	0	0
Energex	3	n.a.	115	1 199	0	100	9	100

Note Certain utilities are not included because information was not available. [a] Indicates the wind velocity the electricity system was designed for.

Source: Data provided by utilities.

Customer demand characteristics

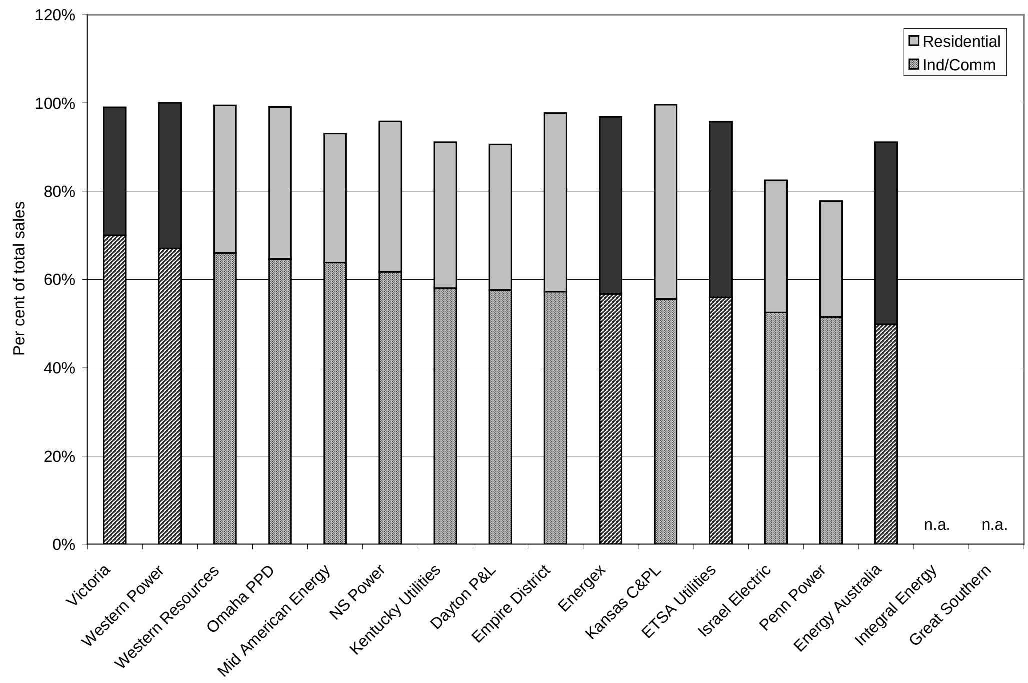
Different levels and temporal patterns of energy consumption affect the incremental and average costs associated with a given set of assets. Where aggregate customer demand is ‘peaky’, there must be sufficient capacity in place in each sector of the industry to meet demand at its peak. However, at least some of this capacity lies idle before and after the peak, increasing average costs.

To some extent, demand management options, such as time-of-use pricing, can enable utilities to better control demand characteristics. However, the efficiency of these mechanisms is diminished by an indirect pricing mechanism where most customers only see an averaged price at the end of a billing period.

Demand patterns are determined to a large extent by the customer mix of a utility’s load. Those utilities that serve a high proportion of industrial sales are likely to have less peaky loads.

For most utilities, only the proportion of load accounted for by industrial and commercial customers was available (see figure 7.7, the Australian utilities are shaded black). The proportion of total sales represented by business customers are reasonably similar across all utilities. However, insufficient data prevented the development of a relationship between costs and the breakdown of load by customer class.

Figure 7.7 **Sales to customer classes, per cent of total sales, 2000**



n.a. Not available. **Note** Breakdown of load between industrial and commercial customers was not available.
Data source: EIA (2000); First Energy Corporation (2000); Data supplied by utilities.

Econometric estimates have focussed upon the relationship between a system's load factor and average costs, and indicate that increasing the load factor will decrease average costs (Fillipini and Wild 2000).

A system load factor is the ratio of a system's average load to its peak load during a specific period of time. A high system load factor indicates that customer demand upon the system is relatively constant, suggesting that industrial sales represent a significant proportion of total customer sales — consistent with the proportion of sales by customer class.

System load factors were not available for all of the utilities studied. However, for the utilities for which information was available, system load factors were broadly similar (see table 7.16, Australian utilities are bolded).

Table 7.16 **System load factors[a], 1999 and 2000**

Utility	*System load factor*
	per cent
Israel Electric	60
NS Power	64
ETSA Utilities	**51**
Western Power	**55**
Empire District	52
NSW	**63**
Vic	**71**
Energex	**65**
Western Resources	56
Omaha PPD	51

a System load factor is the ratio of the average load over a designated period of time to the peak load occurring in that period.

Source: Data provided by utilities; Empire District (2000); ESAA (2000b).

Government imposts and interventions

Some governments have intervened in the electricity industry because of the perceived existence of a market failure, such as monopoly, or to achieve certain social objectives. Interventions are targetted at different levels of the industry and take a variety of forms. For example, they take the form of industry-specific taxes or economic regulation.

Government ownership of utilities may constrain productivity improvement, for example, if investment decisions are influenced by objectives other than profit maximisation.

Industry-specific taxes

The industry-specific taxes that are relevant to the electricity industry are input and output taxes and levies in support of stranded assets or social programs. Also of relevance are regulations that affect the cost of fuel inputs, tax concessions and the use of the electricity industry to subsidise other industries.

Industry-specific taxes are those that apply to the inputs used in the generation, distribution and retailing of electricity. Although economy-wide taxes, such as payroll taxes, apply to the electricity industry, they are not industry-specific and therefore are not considered in this study.

To some extent, economy-wide taxes may be accounted for by the use of purchasing power parities (PPPs) to convert overseas prices to a common unit of account (see chapter 3). However, PPPs may not adequately account for economy-wide taxes when the incidence of these taxes on the electricity industry is greater or less than the economy-wide average.

Taxes on consumption or outputs

Taxes upon final electricity consumption may be levied in two ways — as a percentage of a customer's total electricity bill, or as a cents per kilowatt hour charge that is independent of the price of electricity.

Sales taxes are the most common form of taxation applying to final electricity consumption (see table 7.17, Australian utilities are in bold).

Of greater significance to the price outcomes in chapters 3, 4 and 5 are the range of environmental and other output taxes paid by the utilities. PPPs are unlikely to take full account of these taxes because they are not applicable on an economy-wide basis.

Input taxes and other industry-specific taxes and levies

There may be a range of input taxes and other concessions, levies and social programs, such as the NSW Electricity Distribution Levy (see chapter 2), that may affect final customer prices. However, comprehensive information on the range of such taxes is unavailable.

Table 7.17 **Tax rates on final electricity consumption, Australian dollars, October 2000**

Utility	*Sales tax*[a]	*Environmental taxes*	*Other*
	per cent		
ACTEW	**10**	**n.a.**	**n.a.**
AGL(SA)	**10**	**n.a.**	**n.a.**
Bewag	16	1.6 cents/kWh[b]	2.4 cents/kWh[b]
Dayton P&L	5	0.1 per cent[c]	1.69 cents/kWh[d]
			0.0741 cents/kWh[e]
Empire District	4	n.a.	n.a.
Energex	**10**	**n.a.**	**n.a.**
Energy Australia	**10**	**n.a.**	**n.a.**
Great Southern	**10**	**n.a.**	**n.a.**
Integral Energy	**10**	**n.a.**	**n.a.**
Israel Electric	17	n.a.	0.78 cents/kWh[f]
Kansas CP&L	5	n.a.	n.a.
Kentucky Utilities	6	2.3 per cent	3 per cent[g]
			0.0143 cents/kWh[h]
Mid American Energy	5	0.1482 cents/kWh[i]	1 per cent[j]
		0.4433 cents/kWh[k]	2 per cent[g]
			0.0793 cents/kWh[l]
NS Power	8	n.a.	n.a.
Omaha PPD	5	n.a.	n.a.
Penn Power	6	n.a.	0.7 per cent[m]
			0.0013 cents/kWh[n]
Victorian DBs	**9.87**[o]	**n.a.**	**n.a.**
Western Power	**10**	**n.a.**	**n.a.**
Western Resources	5	n.a.	n.a.

Note Conversion based on PPP rates (see chapter 3). **n.a.** Not applicable. **a** Sales taxes include value-added and goods and services taxes. **b** Concession tax paid to local government for using public ground while transporting energy to the customer. **c** Emission fee recovery charge. **d** Electric fuel component charge. **e** Interim Emergency and Temporary Percentage of Income Payment Charge. **f** Special surcharge to collect government debt. **g** School tax. **h** Fuel adjustment charge. **i** Alternate Energy Producer Cost Recovery Adjustment. **j** Franchise fee. **k** Energy efficiency cost recovery fee. **l** Cooper Nuclear Station Capital Additions Tracker provides a mechanism for recovery of the station capital expenditure. **m** State tax adjustment surcharge. **n** Universal service charge. **o** Allowable GST pass-through varies between Victorian DBs: Citipower 9.85 per cent; AGL(Vic) 9.91 per cent; TXU 9.86 per cent; Powercor 9.87 per cent; and United Energy 9.90 per cent. ESAA chose Powercor to be representative of all five DBs.

Sources: Bewag, Germany, pers. comm., 25 October 2000; Dayton P&L (1999); Department of Finance (Nova Scotia) (2000); Federation of Tax Administrators (US) (2000); Israel Electric, Israel, pers. comm., 21 November 2000; Kentucky Utilities (2000); Mid American Energy Company (1995); NS Power, pers. comm. 6 October 2000; Penn Power (2000); ESAA (2000a).

Economic regulation and institutional context

Economic regulations refer to government policies that affect the economic viability of a utility. The most common forms of economic regulation are dividend and rate of return policies, retail price controls and community service obligations (CSOs).

Dividend and rate of return policies for publicly-owned utilities

Dividend and rate of return policies are only relevant when a utility is publicly-owned. In this study, the publicly-owned utilities are Energy Australia, Integral Energy, Energex and Western Power in Australia, and, of the overseas utilities, Israel Electric and Omaha PPD.

Dividend policies are unlikely to be a major explanator of the price differences found in chapters 3, 4 and 5 as most of the publicly-owned utilities, like the privately-owned utilities, are subject to dividend payment policies. The only utility that is not required to make dividend payments is Omaha PPD.

Rates of return on assets are important for comparison purposes. A publicly-owned utility that is not required to earn a commercial rate of return, may be able to offer lower prices than their private sector counterparts — prices that do not cover full costs, including the cost of capital.

In the financial year 1999-2000, the Australian publicly-owned utilities earned rates of return of between 4 and 14 per cent (PC 2001). These are higher than the rates of return earned by Israel Electric (1 per cent) and Omaha PPD (3 per cent) in their equivalent financial year of 1999 (data provided by Israel Electric; Omaha PPD 2000).[4]

Retail price controls and community service obligation policies

Deregulation of retail prices is more wide-spread in Australia than in the markets of the overseas utilities. At October 2000, the tariff rates that overseas utilities charge each customer class, including large business, are regulated by a public authority (see table 2.1 in chapter 2). By contrast, most Australian business customers that consume more than 160MWh annually were required to negotiate prices with electricity retailers, although in NSW, the Electricity Tariff Equalisation Fund allows customers to opt out (see chapter 2).[5]

Variations in the approach that regulators take to price regulation and in the stringency with which it is applied can directly influence the price comparisons made in chapters 3, 4 and 5. Sound regulation ensures that abuses of market power

4 Omaha PPD is not liable for federal and state income or ad valorem taxes on property. However, payments in lieu of taxes are made to various local governments. These payments have been excluded from earnings in calculating a rate of return.

5 The threshold of 160MWh applies to businesses in New South Wales, Victoria and the Australian Capital Territory. The thresholds in Queensland, South Australia and Western Australia are 200MWh, 750MWh and 8760MWh respectively.

such as monopoly prices are not charged. It can also have an indirect influence on costs by providing incentives for improved productive efficiency. On the other hand, over-zealous regulation can affect profitability and dynamic efficiency, curtailing efficient investment that reduces costs.

There may also be a range of CSOs that the utilities were required to meet. For example, eligible charitable and voluntary organisations can elect to take supply from Western Power on a concessional tariff rate instead of a general supply tariff.

CSOs can distort price comparisons because government requirements for utilities to achieve certain social objectives can result in cross-subsidisation of the prices paid by different customer classes.

A comparison of the retail price and CSO arrangements could not be made because comprehensive information on the arrangements applying to the overseas utilities was unavailable.

7.6 In summary

In assessing the relative efficiency of the studied utilities using prices, it is necessary to take into account the effect that cost factors outside the control of the industry have upon the average prices paid by customers. Utilities can only improve efficiency, and thus lower prices relative to other utilities, to the extent that the costs imposed by these factors allow.

In this study, an attempt has been made to illustrate and analyse the effect that the more important cost factors may have on prices. The focus was on factors considered to be outside the control of utilities in the short-run.

The lack of comprehensive and reliable data on the studied utilities prevents a definitive conclusion being drawn about the relative importance that each factor has on the unadjusted prices observed in chapters 3, 4 and 5. However, the evidence available suggests that the factors considered may explain a large proportion of the observed differences in price outcomes (see table 7.18).

Table 7.18 **Likely significance of factors**

Factor	*Indicative impact upon costs*	*Likely significance as explanator of price difference*
	cents per kWh	
Generation		
Delivered cost of fuels	0.510–3.840	large
Delivered cost of water	unavailable	
Economies of massed reserves	0.020–0.630	small
Age of plant		none to small
Environmental regulation	unavailable	
Transmission and distribution		
Airborne pollution	0.003–0.098	small
Vegetation growth and management	0.030–0.090	small
Requirement to bury cable	0.01-0.09	small
Contributed assets	unavailable	
Economies of output density	unavailable	large
Economies of customer density	unavailable	moderate (urban) large (rural)
Economies of size	unavailable	none to small
Economies of scope: vertical integration	unavailable	
Energy losses	0.410–1.760	small to moderate
Retail		
Economies of scope: multi-product retailing	unavailable	small
Other		
Protection from natural disasters	unavailable	
Terrain and soil conditions	unavailable	
Climate	unavailable	
Customer demand characteristics	unavailable	
Government imposts and interventions		

Note The range in total costs incurred by the utilities from each factor.

Source: PC estimates.

Of the factors considered, variations in economies arising from output density and customer density may be the most significant in explaining price differences. There are statistically significant negative correlations between the rankings of the utilities by prices and their rankings by output density. For other utilities, generation fuel costs may also result in higher costs.

However, further work needs to be undertaken to establish the significance of each of the factors analysed in this study. The development of engineering-based optimisation cost models could contribute to this, and may also assist in a better understanding of the inter-relationships between each factor.

A Participants

Organisations and individuals contacted in the course of the study are listed below.

CitiPower, Victoria

Department of Treasury and Finance, Victoria

Electricity Supply Association of Australia (ESAA)

Energy Users Group of Australia

Hazelwood Power, Victoria

Independent Pricing and Regulatory Tribunal of NSW

Loy Yang Power, Victoria

Office of the Regulator-General, Victoria

United Energy, Victoria

A workshop was held on 9 July 2001 to provide a forum for the discussion of the study methodology, the presentation of results and their interpretations. Drafts of report chapters were circulated prior to the workshop on a ‘confidential work-in-progress’ basis.

Of the organisations invited to attend the workshop, the following participated:

AGL, SA	Integral Energy, NSW
Benchmark Economics	Loy Yang Power, VIC
Country Energy, NSW	Powercor, VIC
ESAA	TXU, VIC
Energex, QLD	UMS Group Australia
Energy Australia, NSW	United Energy, Victoria
Ergon Energy, NSW	Vencorp, VIC
ETSA Utilities, South Australia	Western Power, WA

B Electricity supply

An electricity supply system comprises interconnecting and integrating dispersed generating facilities into a stable synchronised AC (alternating current) network, and the management of equipment failures, network constraints and relations with other interconnected electricity networks. It also involves the scheduling and dispatch of generating facilities that are connected to the transmission network to balance the demand and supply of electricity in real time (Joskow 1998).

The three main components of this system are generation, transmission and distribution.

Transmission networks are generally very high voltage (220kV or higher) networks capable of efficiently conveying large flows of electricity over long distances. Distribution networks are generally lower voltage networks that carry electricity within a more localised geographic area.

B.1 Generation

Generating capacity within a region may be made up of a number of power stations or generating plants. Different generating plants perform specific roles in meeting electricity demand, as demand fluctuates during the day and seasonally through the year.

There is an underlying constant load or ‘base load’ demand for electricity that must be met. These loads tend to be supplied by plants that operate most economically at a relatively constant and high level of output, such as large and new thermal plants.

The system also has to be able to cope with increases in electricity demand that arise during intermediate and peak periods. Plants with higher running costs, such as older thermal plants, normally supply these demands. Alternatively, peak loads might be handled by hydro-electric plants — some of which can only be operated for a few hours at a time.

Variations in plant generating costs arise for a number of reasons, including technology used, generation capacity, plant age, primary energy sources and management and work practices. As a result of cost variations, the way that available generation capacity from different plants is combined to satisfy fluctuating demand patterns has important implications for the cost of electricity to customers (BIE 1996).

B.2 Transmission

The transmission of electricity involves the use of wires, transformers and substation facilities to effect the high voltage 'transportation' of electricity between generating sites and distribution centres.

Most generators participating in the National Electricity Market are connected to transmission networks. However, a small but growing number are connected directly to distribution networks. These are sometimes known as 'embedded' generators (in the sense that they are embedded within a distribution network).

The output of generators is stepped up for more efficient transport at high voltage transmission levels using a step up transformer. The transmission system is used to transport the power close to the load centres, where it is stepped down to lower voltages that are more suited to the distribution subsystem. Within the distribution subsystem, voltages may be stepped down again to levels more suited to customer needs.

Transmission lines can be underground or overhead. Overhead aluminium conductor, steel reinforced conductors are most commonly used for high-voltage transmission lines as they have a relatively low cost and high strength to weight ratio.

Underground transmission is mainly used in urban areas. Underground lines consist of oil-filled cables placed in elaborate duct systems. On average, they cost about 8 to 15 times more than overhead lines. Underground lines are less susceptible to failure but have the disadvantage of poor accessibility in the event that they need to be repaired.

Transformers

Transformers also play an important part in the delivery of electricity to customers. The transformer transfers electrical energy from one circuit magnetically coupled with another. In doing so, they can step up or step down voltage levels in the magnetically coupled circuits.

B.3 Distribution

The distribution system transports power from the transmission system to the customer. It is designed to carry electricity from the point of connection with the transmission system to the customer, and step down the voltage to a level where it can be used by customers. The costs of distribution reflect the transport function and the cost of the transformer system (QEISTF 1996).

Distribution networks are constructed as a hierarchy, with high voltages applying close to the points of supply and stepping down to lower voltages for the supply of smaller customers. Customers may take supply at any of these voltage levels as their needs dictate.

The distribution subsystem includes:

- primary circuits and the distribution substations that supply them;
- secondary circuits, including the components all the way up to the entrance of the customer's premises; and
- protective and control devices.

The primary circuit is three-phase and is operated in the 12-14kV range. The secondary circuits serve most of the customers at levels of 120/240 volts, single-phase, or 480/277 volts three-phase.

Distribution systems are typically radial networks, with only one line to each customer. Since three-phase power is more efficient than single phase, sets of three lines start from each distribution substation. However, as the number of customers remaining on the set decreases, it is often efficient to drop one or two of the three phases. Only a single phase is used in sparsely populated rural areas to reach the most remote customers.

Control devices in distribution systems include voltage regulators and capacitors. Both devices reduce losses and provide the proper voltage at the customer location.[1]

Retailing functions have typically been viewed as an integral component of the distribution function (Joskow 1998). The distribution function typically involves both the provision of the services of the distribution 'wires' to customers as well as a set of retailing functions, including making arrangements for supplies of power from generators, metering, billing and various demand management services.

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[1] A voltage regulator is an auto-transformer with tap positions to raise the voltage to a target value. A capacitor has a timer or a voltage-sensing device to connect the device when the voltage is below a target level.

In vertically disaggregated electricity markets, the retailing function is sometimes separated from the function of delivering electricity through the distribution network.

C Australian and overseas tariffs

The tariffs listed in this appendix were used to calculate the lowest average price per kiloWatt hour for each consumption bundle used for the unadjusted price comparisons in chapters 3, 4 and 5 — where the consumption bundles are defined.

Up to five other tariffs were examined to find the lowest average price for each consumption bundle. However, only the tariff that minimised the cost of the consumption bundles was used to compare annual average prices. These tariffs are listed in tables C.1 through to table C.6.

The Australian tariffs presented in table C.5 were the network charges used in conjunction with annual rolling average spot market prices to compare Australian large business prices for contestable customers with those paid by their overseas counterparts.

C.1 Residential

Table C.1 **Australian utility residential tariffs, October 2000**

	Consumption bundle					
	RB1	*RB2*	*RB3*[a]	*RB4*[a]	*RB5*	*RB6*
ACTEW	Domestic	Domestic	Off-Peak Saver	Off-Peak Saver	Supersaver	Supersaver
Energy Australia	Domestic	Domestic	Off-Peak 1	Off-Peak 1	PowerSmart	PowerSmart
Great Southern Energy	Home Plan Urban	Home Plan Urban	Off-Peak 1	Off-Peak 1	Timesaver	Timesaver
Integral Energy	Domestic	Domestic	Off-Peak 1	Off-Peak 1	Off-Peak 1[a]	Off-Peak 1[a]
Vic DBs	GD & GR	GD & GR	Tariff Y6	Tariff Y6	GD & GR	GH/GL Winner
Energex	Tariff 11	Tariff 11	Tariff 31	Tariff 31	Tariff 31 Off-Peak	Tariff 31 Off-Peak
AGL(SA)	Tariff 110	Tariff 110	Tariff 116	Tariff 116	Standard Domestic – Off-Peak Heating	Standard Domestic – Off-Peak Heating
Western Power	Tariff A1	Tariff A1	Tariff B1	Tariff B1	SmartPower	SmartPower

a Off-Peak heating tariffs applied in conjunction with domestic or general supply tariff.

Sources: ESAA (2000a), PC.

Table C.2 **Overseas utility residential tariffs, October 2000**

Utility	*Consumption bundle*					
	RB1	*RB2*	*RB3*	*RB4*	*RB5*	*RB6*
Bewag	BerlinKlassik	Multi-Connect 24	Multi-Connect 24	Multi-Connect 24	Multi-Connect 24	Multi-Connect 24
Dayton P&L	Residential Rate	Residential Rate	Residential Rate	Optional heating rate (without load metre)	Residential Rate	Optional heating rate (without load metre)
Empire District	RS	RS	RS	RS	RS	RS
Israel Electric	Residential	Residential	Residential	Residential	Residential	Residential
Kansas CP&L	Rate A	Rate A	Rate E	Rate C	Rate C	Rate C
Kentucky Utilities	RSR	FERS	FERS with Off-Peak Hot Water	FERS with Off-Peak Hot Water	FERS with Off-Peak Hot Water	FERS with Off-Peak Hot Water
Western Resources	Conservation Service	Conservation Service	Conservation Service	Home Heating Service	Conservation Service	Home Heating Service
Mid-American Energy	RWS	RWS	RWS	RES	RWS	RES
NS Power	Domestic Service Rate	Domestic Service Rate	Domestic Time-of-use	Domestic Time-of-use	Domestic Service Rate	Domestic Time-of-use
Omaha PPD	Regular Rate	Regular Rate	Regular Rate	Special Winter Rate	Regular Rate	Special Winter Rate
Penn Power	RH	RS	RH with water heating	RH with water heating	RH with water heating	RH with water heating

Source: PC.

C.2 Small to medium business

Table C.3 **Australian utility small to medium business tariff, October 2000**

Utility	*Consumption bundle*					
	SB1	*SB2*	*MB1*	*MB2*	*MB3*	*MB4*
Great Southern Energy	Bislink (Business Time-of-use) urban	Bislink (Business Time-of-use) urban	Bislink (Business Time-of-use) urban	Bislink (Business Time-of-use) urban	Bislink (Business Time-of-use) urban	Bislink (Business Time-of-use) urban
AGL(SA)	General Supply Time-of-use Tariff 128	General Supply Time-of-use Tariff 128	General Supply Time-of-use Tariff 128	General Supply Time-of-use Tariff 128	Time-of-use Demand Tariff 160	Time-of-use Demand Tariff 160
Energy Australia	Loadsmart Demand Tariff	General Supply Tariff	General Supply Time-of-Use Tariff	Loadsmart Demand Tariff	General Supply Time-of-Use Tariff	Loadsmart Demand Tariff
ACTEW	Business Incentive Time-of-use	General	LV Time-of-use demand	LV Time-of-use demand	LV Time-of-use demand	LV Time-of-use demand
Vic. DBs	General Purpose Time-of-use Tariff D	General Purpose Time-of-use Tariff D	General Purpose Time-of-use Tariff D	Contract Demand Time-of-use Tariff L	Contract Demand Time-of-use Tariff L	Contract Demand Time-of-use Tariff L
Integral Energy	General Supply Time-of-use (Code 820)	General Supply Time-of-use (Code 820)	General Supply Time-of-use (Code 820)	General Supply Time-of-use (Code 820)	General Supply Time-of-use (Code 820)	Time-of-use Demand Pricing (LV)
Energex	Tariff 22 – General Supply – Time-of-use	Tariff 20 – General Supply	Tariff 41 – LV General Supply Demand	Tariff 41 – LV General Supply Demand	Tariff 41 – LV General Supply Demand	Tariff 41 – LV General Supply Demand
Western Power	R1 Time-of-use	R1 Time-of-use	R1 Time-of-use	R1 Time-of-use	S1 Time-of-use Demand LV (415V)	S1 Time-of-use Demand LV (415V)

Source: PC.

Table C.4 **Overseas utility small to medium business tariffs, October 2000**

Utility	*Consumption bundle*					
	SB1	*SB2*	*MB1*	*MB2*	*MB3*	*MB4*
Penn Power	General Service – Small – GS	General Service – Small – GS	General Service – Medium – GM	General Service – Medium – GM	General Service – Medium – GM	General Service – Medium – GM
Mid American Energy[a]	GUS – General Service Time-of-use – Secondary Voltage	GUS – General Service Time-of-use – Secondary Voltage	GBS – General Service Base – Energy Only Metering	GUS – General Service Time-of-use – Secondary Voltage	LLS, LLC and ALS – Base Use at Secondary Voltage	LLS, LLC and ALS – Base Use at Secondary Voltage
Kentucky Utilities	LP – Combined Lighting and Power Service (Secondary Service)	LP – Combined Lighting and Power Service (Secondary Service)	LP – Combined Lighting and Power Service (Secondary Service)	LP – Combined Lighting and Power Service (Secondary Service)	LP – Combined Lighting and Power Service (Secondary Service)	LP – Combined Lighting and Power Service (Secondary Service)
Dayton P&L	General Service Secondary Rate	General Service Secondary Rate	General Service Secondary Rate	General Service Secondary Rate	General Service Secondary Rate	General Service Secondary Rate
Kansas CP&L	SGS – Small General Service	SGS – Small General Service	MGS – Medium General Service	MGS – Medium General Service	LGS – Large General Service	LGS – Large General Service
Empire District	Commercial Service – CB	Commercial Service – CB	General Power Service – GP	General Power Service – GP	General Power Service – GP	General Power Service – GP
Omaha PPD	General Service – Demand	General Service – Nondemand	General Service – Demand	General Service – Demand	General Service – Demand	General Service – Demand
Western Resources	General Service	General Service	General Service	Large General Service	General Service	Large General Service
NS Power	Small Industrial Rate (Code 21)	Small Industrial Rate (Code 21)	Small Industrial Rate (Code 21)	Small Industrial Rate (Code 21)	Medium Industrial Rate (Code 22)	Medium Industrial Rate (Code 22)
Israel Electric	General	General	Time-of-use	Time-of-use	Time-of-use	Time-of-use

a Tariff rate schedules for the South System were used as the largest city covered by the utility (Des Moines) is located in the South System.

Source: PC.

C.3 Large business

Table C.5 **Australian utility large business tariffs, October 2000**

Utility	*Consumption bundle*					
	LB1	*LB2*	*LB3*	*LB4*	*LB5*	*LB6*
Great Southern Energy	Urban LV Demand	Urban LV Demand	HV Demand (Network)	HV Demand (Network)	HV Demand (Network)	HV Demand (Network)
AGL(SA)	LV Demand	LV Demand	HV	HV	ST Time-of-use Demand Eligible	ST Time-of-use Demand Eligible
Energy Australia	LV KVA Demand Time-of-use (System)	LV KVA Demand Time-of-use (System)	HV Demand Time-of-use (System)	HV Demand Time-of-use (System)	HV Demand Time-of-use (System)	HV Demand Time-of-use (System)
ACTEW	LV network use-of-system	LV network use-of-system	HV network use-of-system with ACTEW LV network	HV network use-of-system with ACTEW LV network	HV network use-of-system with ACTEW LV network	HV network use-of-system with ACTEW LV network
CitiPower	Large LV	Large LV	HV	HV	HV	HV
United Energy	LV Large 2 rate KVA – (LVL2R.KVA)	LV Large 2 rate KVA – (LVL2R.KVA)	HV KVA	HV KVA	HV KVA	HV KVA
Powercor	Large LV demand (DL)	Large LV demand (DL)	HV (DH)	HV (DH)	HV (DH)	HV (DH)
Integral Energy	LV Time-of-use Demand Eligible	LV Time-of-use Demand Eligible	HV Time-of-use Demand Eligible	HV Time-of-use Demand Eligible	HV Time-of-use Demand Eligible	HV Time-of-use Demand Eligible

Source: PC.

Table C.6 Overseas utility large business tariffs, October 2000

Utility	*Consumption bundle*					
	LB1	*LB2*	*LB3*	*LB4*	*LB5*	*LB6*
Penn Power	General Service - Medium - GM	General Service - Medium - GM	General Service – Primary - GP	General Service – Primary - GP	General Service – Primary - GP	General Service – Primary - GP
Mid American Energy[a]	LLS, LLC and ALS – Base Use at Secondary Voltage	LLS, LLC and ALS – Base Use at Secondary Voltage	LPS, LPC and APS – Base Use at Primary Voltage	LPS, LPC and APS – Base Use at Primary Voltage	LPS, LPC and APS – Base Use at Primary Voltage	LVS/LRS – Time-of-Use at Primary Voltage
Kentucky Utilities	High Load Factor (Secondary Service)	High Load Factor (Secondary Service)	LP – Combined Lighting and Power Service (Primary Service)	High Load Factor (Primary Service)	LP – Combined Lighting and Power Service (Primary Service)	High Load Factor (Primary Service)
Dayton P&L	General Service Secondary Rate	General Service Secondary Rate	General Service Primary Rate	General Service Primary Rate	General Service Primary Rate	General Service Primary Rate
Kansas CP&L	LGS – Large General Service (Secondary voltage)	LGS – Large General Service (Secondary voltage)	LGS – Large General Service (Primary voltage)	LPS – Large Power Service (Primary voltage)	LGS – Large General Service (Primary voltage)	LPS – Large Power Service (Primary voltage)
Empire District	General Power Service - GP	General Power Service - GP	Large Power Service - LP	Large Power Service - LP	Large Power Service - LP	Large Power Service - LP
Omaha PPD	General Service – Demand	General Service – Demand	General Service – Demand	General Service – Demand	General Service – Demand	General Service – Demand
Western Resources	General Service	Large General Service	General Service	High Load Factor Service	General Service	High Load Factor Service
NS Power	Medium Industrial Rate (Code 22)	Medium Industrial Rate (Code 22)	Medium Industrial Rate (Code 22)	Medium Industrial Rate (Code 22)	Large Industrial Rate	Large Industrial Rate

a Tariff rate schedules for the South System were used as the largest city covered by the utility (Des Moines) is located in the South System.

Source: PC.

Glossary

Adequacy	A bulk electric power system's ability to supply the aggregate electrical demand and energy requirements of customers at all times.
Alternating current (AC)	A flow of electricity current that reverses its direction at regularly recurring intervals of time and that has alternately positive and negative values. Almost all electrical utilities generate AC electricity because it can easily be transformed to higher or lower voltages.
Arrester	A protective device for limiting surge voltages on equipment by diverting surge current and returning the device to its original status. It is capable of repeating these functions as specified.
Average cost pricing	A pricing mechanism based on dividing the total cost of providing electricity incurred in a period by the number MWh (wholesale) and kWh (retail) sold in the same period.
Average demand	The measure of the total of energy loads placed by customers on a system divided by the time period over which the demands are incurred.
Average distribution loss factor	These measure the loss of energy across a distribution network, usually comprising the subtransmission, distribution and low-voltage wires.
Average revenue per kilowatt hour	Calculated by dividing the total monthly revenue in any given period by the corresponding total.
Avoided cost	The cost to produce or otherwise procure electrical power that electrical utilities do not incur when they reduce output
Base load	The minimum amount of electricity power delivered or required over a given period of time at a steady rate.

Base load capacity The generating equipment normally operated to serve loads on an around-the-clock basis.

Base load plant A plant which is normally operated to take all or part of the minimum continuous load of a system, and which consequently produces electricity at an essentially constant rate.

Block tariffs A rate structure that prices successive blocks of power use at different per-unit prices. The most common form is for the per-unit price to decline as the level of consumption increases.

Brownout The partial reduction of electrical voltages caused by customer demand being higher than anticipated or by the failure of the generation, transmission or distribution system.

Capacitor An electrical device used to store electrical energy, and to release it back into the power system when required.

Capacity The real power output rating of a generator or system, typically in megawatts, measured on an instantaneous basis.

Capacity margin The amount of capacity above planned peak system demand available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen electricity demand.

Cogeneration The simultaneous production of both useable heat or steam and electricity from a common fuel source.

Cogenerator An entity owning a generation facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial heating, or cooling purposes.

Conductivity A measure of a material's ability to conduct/transmit an electric charge.

Conductor Any material which allows electrons to flow through it, usually in the form of a wire, cable or bushbar.

Congestion costs	Costs that arise from the re-dispatch of a system due to transmission constraints.
Contestable customers	customers who are able to choose who they purchase their electricity from.
Continuous rating	The constant load which a device can carry at rated primary voltage and frequency without damaging and/or adversely effecting its characteristics.
Cost of service	The total amount of money, including return on invested capital, operation and maintenance costs, administrative costs, taxes and depreciation expense, to produce a utility service.
Current (electric)	The rate of movement of electrons through a conductor, measured in amperes.
Current diversion (or energy diversion)	Theft of electrical power in which current is diverted to bypass the metre. More generally, any type of tampering to obtain un-metered service.
Curtailment	A temporary, mandatory load reduction taken when there is a risk that the utility cannot meet its power requirements and retain a prudent reserve margin.
Customer density	Number of customers per kilometre of network
Demand	The rate at which electrical energy is delivered to or by a system at a given instant or averaged over a designated period, usually expressed in kilowatts or megawatts.
Demand charge	The demand charge portion of rate design is expected to recover the costs associated with capital-related costs and the cost of operation and maintenance of generation, transmission and distribution.
Demand forecast	An estimate of the level of energy or capacity that is likely to be needed at some time in the future.
Demand-side management (DSM)	The terms for all activities or programs undertaken by an electrical system or its customers to influence the amount and timing of electricity use.

Depreciation	The loss of value of assets, such as buildings and transmission lines, due to age and wear. Depreciation is charged to utility customers as an annual expense.
Direct current (DC)	An electric current that flows in one direction with a magnitude that does not vary or that varies only slightly.
Disaggregation	The breaking up of the traditional electrical utility structure from a totally bundled service to an ala carte service.
Dispatch	The monitoring and regulation of electrical system to provide coordinated operation; the sequence in which generating resources are called upon to generate power to serve fluctuating loads.
Distribution network	The system of lines, transformers and switches that connect between the transmission network and customer load. It is dedicated to delivering electrical energy to an end-user at relatively low voltages.
Distributed generation	Electrical power produced elsewhere than a central station generating unit, such as that using fuel cell technology or on-site small scale generating equipment.
Distribution losses	Energy losses due to impedence in the distribution network.
Distribution voltage	The voltage in the electric system between substation and ultimate utilisation. Normally recognised as power lines that would supply commercial/residential facilities.
Economic dispatch	The process of determining the desired generation level for each of the generating units in a system in order to meet customer demand at the lowest possible production cost given the operational constraints on the system.
Economies of customer density	Economies of customer density exist if unit costs decrease with an equi-proportional increase in output and customer numbers, holding the size of the service area fixed.
Economies of massed reserves	Economies of massed reserved arise when it costs proportionally less to maintain the capacity required to meet peak demand and allow for equipment failure when there are a large number of interconnected generation units.

Economies of output density	Economies of output density exist where unit costs decline with an increase in output, holding the size of the service area and the number of customers fixed.
Economies of scope	Economies of scope exist where it is less costly to combine two or more product lines in one firm than to produce them separately. In the electricity industry, economies of scope may be realised through vertical integration, or through multi-retailing of products.
Economies of size	Economies of size exist if unit costs decrease with an equi-proportional increase in output and the number of customers, while output per customer and customers per line kilometre remain fixed.
Elasticity of demand	The degree to which customer demand for a product responds to changes in price, availability or other factors.
Electro magnetic fields (EMF)	Invisible force fields that surround the movement of electricity.
Embedded cost	Historical cost of all facilities in the power supply system.
Emergency rating	The rating, as defined by the facility owner, that specifies the level of electrical loading (generally expressed in megawatts or other appropriate units) that a facility can support or withstand for short periods of time.
Emergency voltage limits	The operating voltage range on the interconnected systems, above or below nominal voltage and expressed in kiloVolts at the transmission or distribution level and volts at the utilisation level, that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.
Energy	The capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy).
Energy charge	That portion of the charge for electrical service based upon the electrical energy (kWh) consumed or billed. The commodity charge.

Energy losses	Where energy is lost in the reticulation of electricity due to impedence.
Fixed charge	The charge calculated in rate design to recover all or a portion of the fixed costs of a utility plant, including the generation facility and transmission lines, meters, and some taxes.
Fixed cost	Cost of facilities incurred regardless of the amount of energy produced. Such costs normally include capital costs, the cost of financing construction, and insurance.
Fly ash	The finely divided particles of ash entrained in flue gases arising from the combustion of fuel.
Forced outage	The shutdown of a generating unit, transmission line or other facility, for emergency reasons.
Forced outage rate	The rate of shutdown of a generating unit, transmission line, or other facility, for emergency reasons or a condition in which the generating equipment is unavailable for load because of unanticipated breakdown.
Forced outage reserves	An amount of peak generating capability planned to be available to serve peak loads during forced outages.
Frequency	The oscillatory rate in Hertz (cycles per second) of the alternating current electrical service.
Full-forced outage	The net capability of main generating units that is unavailable for load for emergency reasons.
Generating unit	Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electrical power.
Generation (electricity)	The process of producing electrical energy by transforming other forms of energy such as steam, heat or falling water. Also, the amount of electrical energy produced, expressed in kiloWatt-hours (kWh) or MegaWatt-hours (MWh).

Generator	A machine that converts mechanical energy into electrical energy. Generally rated in terms of real power (MW) and reactive power (MVARs) output or in terms or real power output (megawatts) and power factor. Generators require a source of mechanical energy input (typically a turbine) and ancillary equipment to interface with the transmission network. Also, a person or firm that operates a generator.
Geothermal	Power generated from heat energy derived from hot rock, hot water, or steam below the earth's surface.
Grid	The layout of the electrical transmission system or a synchronised transmission network.
Hydroelectric plant	A plant in which the turbine generators are driven by falling water.
Impedance	The opposition in an electrical circuit to the flow of alternating current (AC). The ratio of electromotive force to the effective current.
Interchange (or transfer)	The net of all power flows across the tie lines of a given control area or the net of all power flows between two adjacent control areas.
Interconnection	When one electrical system is connected to another.
Interruptible load	Demand that can be interrupted by direct action of the supplying system's system operator in accordance with contractual provisions at times of seasonal peak load. It usually involves commercial and industrial customers.
Joules	A measure of energy equal to 1 Watt second.
Kilowatt (kW)	A unit of electrical power equal to one thousand Watts.
Kilowatt-hour (kWh)	A unit of electrical energy which is equivalent to one kilowatt of power used for one hour.
Load	The amount of electrical power delivered or required at any specific point or points on a system, usually measured in MegaWatts.

Load curve A curve of power versus time showing the level of a load for each time period covered. The horizontal axis is time and the vertical access is load (MW).

Load duration curve A curve of loads, plotted in descending order of magnitude, against time intervals for a specified period. The curve indicates the period of time load was above certain magnitude.

Load factor The ratio of average load to peak load during a specific period of time, expressed as a percent. An electrical system's load factor indicates the variability in all customers' demands.

Load management The management of load patterns in order to better utilise the facilities of the system. Generally, the aim of load management is to shift load from peak use periods to other periods of the day or year.

Long run marginal costs All costs associated with the lowest cost incremental unit including variable production costs, fixed O&M, and capital costs.

Loop flow The tendency of electricity to flow along the path of least resistance, which may not necessarily be the same as that intended in the contract between the two transmitting entities.

Loss of load probability (LOLP) A measure of expectation that system demand will exceed capacity during a given period, often expressed as the expected number of days per year (for example, one day in ten years).

Maintenance outage The planned removal of an electrical facility from service to perform scheduled maintenance on that facility.

Marginal cost pricing A system of pricing designed to ignore all costs except those associated with producing the next increment of power generation. Sometimes referred to as incremental cost pricing.

Massed reserves	The quantity of reserve plant that must be held to meet peak demand declines and allow for equipment failure declines as the number of interconnected generators increases.
MegaWatt (MW)	A unit of electrical power equal to one million Watts or one thousand kiloWatts.
MegaWatt-hour (MWh)	One million Watt-hours of electrical energy. A unit of electrical energy which equals one megawatt of power used for one hour.
Merit dispatch	See Economic Dispatch. The process of dispatching generator units in order of ascending marginal costs of production.
Nameplate capacity	The full-load continuous rating of a generator, prime mover, or other electric power production equipment under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.
Net capability	The maximum load-carrying ability of a power plant, exclusive of station use, under specified conditions for a given time interval, independent of the characteristics of the load.
Network	An interconnected system of electrical transmission lines, transformers, switches and other equipment connected together in such a way as to provide reliable transmission of electrical power from multiple generators to multiple load centres. A network implies redundancy provided through the use of multiple parallel flow paths.
Nominal voltage	The voltage standards recommended by manufacturers of electrical equipment and the electrical utilities to assure that electrical equipment will be designed for the voltage range that will be encountered in actual use so that satisfactory operation of equipment will be obtained.
Non-contestable customers	Customers who receive services from a distributor located within the geographical franchise supply region.

Normal rating	The ratings as defined by the facility owner that specify the level of electrical loading (generally expressed in megawatts or other appropriate units) that a facility can support or withstand through the daily demand cycles without loss of equipment life of the facility or equipment involved.
Normal voltage limits	The operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kiloVolts, that is acceptable on a sustained basis. (See Voltage Chart.)
Off-peak	A period of relatively low demand for electrical energy, such as the middle of the night.
Ohm	The unit of measurement of electrical resistance. The resistance of a circuit in which a potential difference of 1 Volt produces a current of 1 ampere.
Operating reserve	The reserve generating capacity necessary to allow an electrical system to recover from generation failures and provide for load following and frequency regulation. It consists of spinning and non-spinning reserves.
Operating security	The ability of a power system to withstand or limit the adverse effects of any credible contingency to the system including overloads beyond emergency ratings, excessive or inadequate voltage, loss of stability or abnormal frequency deviations.
Outage	Periods, both planned and unexpected, during which power system facilities (generating unit, transmission line, or other facilities) cease to provide generation, transmission, or the distribution of power.
Peak demand	The maximum load during a specified period of time.
Peak load	The maximum electrical load demand in a stated period of time.

Peak load plant or unit	A plant usually housing low-efficiency, quick response steam units, gas turbines, diesels, or pumped-storage hydroelectric equipment normally used during the maximum load periods. Peakers are characterised by quick start times and generally high operating costs, but low capital costs.
Peaking capacity	Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis.
Power	A term usually meant to imply both capacity and energy. The rate at which energy is transferred. Electrical energy is usually measured in watts.
Power factor	The fraction of power actually used by a customer's electrical equipment compared to the total apparent power supplied, usually expressed as a percentage. Power factors apply only to alternating current circuits; direct current circuits always exhibit a power factor of 100 percent. A power factor indicates how far a customer's electrical equipment causes the electrical current delivered at the customer's site to be out of phase with the voltage.
Power factor adjustment	A calculation or charge on industrial or commercial customers' bills reflecting an adjustment in billing demand based on customer's actual metered power factor. If the power factor stays within a specified range, there is no adjustment.
Power pool	An association of two or more interconnected electrical systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.
Price cap	A method of setting a utility distribution company's rates whereby a maximum allowable price level is established by regulators, flexibility in individual pricing is allowed, and where efficiency gains can be encouraged and captured by the company.

Pumped-storage hydroelectric plant	A plant that generates electrical energy by using water pumped during off-peak periods into an elevated storage reservoir. At peak periods, when additional generating capacity is needed, the water is released from the elevated storage reservoir to turbine generators in a power plant at a lower elevation.
Purchasing Power Parity	The rates of currency conversion that equalise the purchasing power of currencies — that will buy the same broadly defined basket of goods and services in all countries.
Ratchet or ratcheted demand charge	The Demand Charge level that a customer pays each month regardless of actual consumption based on the peak consumption rate during a rolling period of time (usually 12 months.)
Reactive power	Reactive power is utilised to control voltage on the transmission network, particularly, the portion of the electrical power flow incapable of performing real work or energy transfer. Reactive power is that portion of electricity that establishes and sustains the electrical and magnetic fields of alternating current equipment.
Reactive power generation	The production of electrical current that leads or lags the phase of the electrical voltage. Reactive power supplies the charging power for electromagnetic loads and the reactive needs of the transmission system.
Real time pricing	Time of day pricing whereby the customer receives frequent signals on the cost of consuming electricity at that time.
Reliability	The degree to which the performance of the elements of a system results in power being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on customer service.
Reserve capacity	Extra generating capacity available to meet unanticipated demands for power or to generate power in the event of loss of generation.

Reserve plant margin The proportion of installed generation capacity held that is over and above the annual peak demand.

Scheduled outage The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

Short run marginal cost All variable production costs.

Spinning reserve Unused capacity available from units connected to and synchronised with the grid to serve additional demand. The spinning reserve must be under automatic governor control to instantly respond to system requirements.

Stranded asset An asset with a cost recovery schedule that was initially approved by regulatory action that subsequent regulatory action or market forces has rendered not practically recoverable.

Transformer An electrical device for changing the voltage of alternating current.

Transmission The network of high voltage lines, transformers and switches used to move electrical power from generators to the distribution system. Also utilised to interconnect different utility systems and independent power producers together into a synchronised network. Transmission is considered to end when the energy is transformed for distribution to the customer.

Transmission grid An interconnected system of electric transmission lines and associated equipment for the transfer of electrical energy in bulk between points of supply and points of demand.

Transmission losses The power lost in transmission between one point and another. It is measured as the difference between the net power passing the first point and the net power passing the second point.

Transmission system An interconnected group of electric transmission lines and associated equipment for moving or transfer transformed for delivery over the distribution system lines to customers, or is delivered to other electrical systems.

Transmission voltage Voltage levels utilised for bulk transmission systems.

Unbundled services The selling and pricing of services separately as opposed to offering services 'bundled' into packages with a single price for the whole package.

Variable cost The total costs incurred to produce energy, excluding fixed costs which are incurred regardless of whether the resource is operating. Variable costs usually include fuel, increased maintenance and additional labour.

Vesting contracts Vesting contracts are contractual arrangements that are designed to reduce the price volatility associated with the sale of electricity in a competitive market. They are financial hedging instruments that provide fixed prices with reference to the variable pool price, and thus minimise the financial risk and exposure of retailers to fluctuating prices.

Volt The unit of measurement of electromotive force. It is equivalent to the force required to produce a current of one ampere through a resistance of one ohm. The unit of measure for electrical potential. Generally measured in kiloVolts or kV.

Watt A measure of real power production or usage equal to one Joule per second. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 Volt at unity power factor. An electrical unit of power or a rate of doing work.

Watt-hour (Wh) An electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electrical circuit steadily for 1 hour.

Wholesale sales Energy supplied to other electrical utilities for resale to ultimate customers.

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