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COMMISSION

Energy Generation and Distribution

Volume III: Supporting Appendixes

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APPENDIX 1: TERMS OF REFERENCE AND CONDUCT OF THE INQUIRY

1.1 Terms of reference and Treasurer's press release

The reference, which was received on 21 May 1990, required the Commission to report within twelve months.

The main focus of the inquiry is on whether there is potential for improving the efficiency of electricity and gas supply and use in Australia and, if so, the means by which improvements may best be achieved.

The activities covered by the reference are the generation of electricity and the transmission and distribution of electricity and gas. Tax, resource rent and royalty issues relating to gas are excluded from the reference.

The terms of reference are shown immediately preceding Chapter 1. The Treasurer's press release announcing the inquiry, is set out at Attachment 1.1 to this appendix.

By letter of 5 December 1990, the Treasurer informed the Commission that the Government was forwarding it a reference on greenhouse gases emissions. In view of the overlap between that new inquiry and this reference on energy generation and distribution, the Treasurer indicated that clause 3(i) of this inquiry was deleted from the terms of reference (see Attachment 1.2). The clause had required the Commission to have regard to the relative efficiency and cost effectiveness of options to reduce the environmental impact of burning fossil fuels.

1.2 Conduct of the inquiry

In June 1990, the Commission released an issues paper to assist participants in preparing their submissions for the initial round of public hearings. In contrast to electricity, the Commission found that published work covering the natural gas industry was limited. Consequently, a background paper on gas was also released in June 1990 to help bridge this information gap and stimulate discussion.

In the early stages of the inquiry, the Commission held discussions with a wide range of interested parties in all states and territories (see Attachment 1.4). The purpose of the discussions was to establish lines of communication, to identify and canvass views on likely issues, to discuss the Commission's approach to the inquiry and to ascertain the nature and availability of relevant information.

The Commission conducted an initial round of public hearings to obtain background information on the electricity and gas supply industries and to seek participants' views on key issues. Public hearings were held at:

- Brisbane 13 August 1990
- Melbourne 15 & 16 August 1990
- Sydney 20 & 21 August 1990
- Canberra 27 - 29 August 1990

The Commission released a draft report on 15 January 1991 and subsequently conducted a further round of public hearings to enable interested parties to respond to the Commission's recommendations and analysis prior to the report being finalised. Public hearings were held at:

- Melbourne 5 March 1991
- Sydney 7 & 8 March 1991
- Canberra 12, 14 & 15 March 1991

The 101 organisations and individuals who have made submissions to the inquiry are listed at Attachment 1.3.

Attachment 1.1: Treasurer's press release

STATEMENT BY THE TREASURER, THE HON PAUL KEATING, MP

INDUSTRY COMMISSION INQUIRIES INTO ENERGY GENERATION AND DISTRIBUTION, RAIL TRANSPORT AND STATUTORY MARKETING ARRANGEMENTS

I am forwarding today a further instalment of major references to the Industry Commission covering energy generation and distribution, rail transport and statutory marketing arrangements. The terms of reference for these inquiries are attached.

The three references, which were foreshadowed in my August 1989 budget announcement on the Industry Commission, have been developed in consultation with all States and Territories.

Preliminary studies conducted by the Industries Assistance Commission last year estimated potential annual gains of $2.6 billion from Australia's rail freight services and $1 billion from electricity supply if public enterprises in these industries achieved identified improvements in efficiency. The energy and rail references announced today will permit the new Industry Commission to investigate more intensively the opportunities for improved performance in these important sectors of the economy.

The inquiry into energy generation and distribution will examine the scope for improving the efficiency of electricity generation and the transmission and distribution of electricity and gas. Pricing, organisational arrangements, the private provision of generating capacity, management and work practices, efficiency in the use of energy and options are some of the issues under review. The inquiry is of twelve months duration.

The Industry Commission is to report on statutory marketing arrangements for primary products (other than mining and forestry). The inquiry will identify and evaluate the objectives of Commonwealth, State and Territory arrangements and report on the scope for increasing efficiency. The inquiry is of ten months duration.

The reference on Australia's rail transport system encompasses the carriage of passengers and freight in both city and country areas. The inquiry will examine measures through which rail systems can provide more efficient services including management and work practices, pricing policies, funding for infrastructure, and the potential for public/private development. The economic and environmental implications of regulatory and other arrangements affecting rail and other transport modes will also be examined. The inquiry is of fifteen months duration.

The Commission will need to consult widely with government agencies, industry organisations and other community groups. Cooperative and active participation by State and Territory Governments will be important for the success of these inquiries because of their central role in the provision and regulation of energy supply, rail transport and statutory marketing arrangements for primary products.

All levels of government are committed to lifting the productive potential of the economy. Through its public inquiry processes and broad based analysis the Commission can help build community awareness and support for necessary change. These inquiries will help to underpin reform efforts currently underway in the States and be a catalyst for further significant reform at all levels of government.

CANBERRA ACT

20 May 1990

Attachment 1.2: Amendment to terms of reference

Mr A. S. Cole
Chairman
Industry Commission
Benjamin Offices
Chan Street
BELCONNEN ACT 2600

Dear Mr Cole

The Government is forwarding a reference to the Commission on greenhouse gas emissions. There is an overlap between this new inquiry and the Commission's current reference on energy generation and distribution where, among other matters, it is to report on the relative efficiency and cost effectiveness of options to reduce the environmental impact of burning fossil fuels.

I see considerable merit in your suggestion that the Commission consolidate its work on this issue in the new reference on greenhouse gas emissions. Accordingly, I am prepared to exercise my powers under section 7(2) of the Industry Commission Act and amend the terms of reference on energy generation and distribution dated 20 May 1990 by deleting clause 3(i).

Yours sincerely

P. J. Keating

5 December 1990

Attachment 1.3: Inquiry participants

The 101 organisations and individuals who made submissions to the inquiry are listed below. Participants marked * presented submissions at public hearings conducted in August 1990 and March 1991. The remainder made written submissions only.

Participant	Date of Submission	Submission number
ABB ASEA Brown Boveri Pty Ltd*	6-08-90	18
	25-10-90	80
ACT Electricity and Water* (ACTEW)	17-08-90	42
	16-04-91	156
AGL Gas Companies* (AGL)	10-08-90	31
	28-09-90	79
	26-03-91	146
	5-04-91	149
AGL Gas Companies & AGL Petroleum	1-03-91	103
AGL Petroleum*	8-08-90	25
Allgas Energy Limited	18-03-91	139
Arts, Sport, the Environment, Tourism and	6-09-90	69
Territories, The Department of (DASETT)	4-04-91	148
Association of Professional Engineers Australia	9-11-90	83
	8-03-91	117
Australian and New Zealand Solar Energy Society*	1-08-90	22
Australian Bureau of Agricultural & Resource Economics* (ABARE)	8-03-91	128
Australian Chamber of Manufactures*	6-08-90	29
	21-12-90	89
	1-03-91	104
Australian Coal Association	31-08-90	65
Australian Conservation Foundation* (ACF)	22-08-90	48
	14-03-91	111
Australian Consumers' Association	6-08-90	14
Australian Electrical & Electronic*	22-08-90	45
Manufacturers' Association	22-04-91	159

Participant	Date of Submission	Submission number
Australian Federation of Construction Contractors	28-08-90 5-03-91	60 119
Australian Gas Association* (AGA)	20-08-90 28-02-91	43 101
Australian Mining Industry Council	5-10-90	78
Australian Petroleum Exploration Association Limited	10-08-90	37
Australian Pipeline Industry Association	20-09-90 25-02-91	75 100
BHP Petroleum* (BHPP)	23-08-90 14-09-90 5-03-91	49 74 114
BHP Steel - Collieries Division*	16-08-90 24-09-90	39 76
BP Australia Limited	1-03-91	121
BTR Engineering (Australia) Limited	6-03-91	123
Central West Electricity	12-03-91	142
Chamber of Commerce and Industry South Australia	28-08-0-	64
City of Box Hill Electricity Supply*	6-08-90 17-08-90	13 41
City of Brunswick Electricity Supply	30-08-90 15-03-91	61 144
Commonwealth Scientific and Industrial Research Organisation (CSIRO) - Division of Materials Science	2-08-90	12
Community Energy Network	22-08-90	51
Confederation of Western Australian Industry	21-06-90	1
Conservation Council of South Australia	10-09-90 23-12-90	70 90

Participant	Date of Submission	Submission number
CRA Limited* (CRA)	13-08-90	33
	19-02-91	95
	4-03-91	105
	5-03-91	118
	20-03-91	147
Derry, Mr Michael	28-08-90	57
Dickinson, Sir Ben	20-08-90	52
	31-01-91	93
Domestic Gas Venture North West Shelf Project	10-08-90	35
	6-03-91	124
Ecogen Pty Ltd	23-07-90	2
Electricity Commission of New South Wales (ECNSW)	6-03-91	116
Electricity Commission of New South Wales* (ECNSW) Electricity Council of New South Wales* Gas Council of New South Wales*	1-03-91	113
Electricity Supply Association of Australia* (ESAA)	14-08-90	36
	21-12-90	91
	7-03-91	125
Electricity Week	10-08-90	28
Energy Action Group*	28-08-90	59
	4-03-91	112
Energy Science and Technology Policy Committee - ALP, Vic.	3-08-90	10
Engineering and Water Supply Department, South Australia	31-07-90	5
Esso Australia Resources Ltd (ESSO)	7-08-90	20
	21-02-91	98
Engineering Employers' Association of South Australia, The	28-08-90	64
Fibreglass and Rockwool Insulation Manufacturers Association of Australia Inc.	19-03-91	140
Gas Corporation of Queensland Limited (GCQ)	21-03-91	141

Participant	Date of Submission	Submission number
Gas and Fuel Corporation of Victoria* (GFCV)	9-08-90 22-10-91 6-03-91	26 81 126
Greene, Deni	8-05-91	163
ICI Australia Limited	7-09-90.	71
ICL Australia Pty Limited*	3-08-90	9
Incitec Limited*	10-08-90	17
Institution of Engineers, Australia*	15-08-90	38
Intelligent Energy Systems Pty Ltd (IES) (Mr C. H. Bannister)*	7-02-91	92
Koerner, Mr R. J.	22-08-90	53
Laird, Dr Philip	2-08-90 12-03-91	4 131
Latrobe Regional Commission*	6-08-90 13-03-91	19 130
Latrobe Valley Community Forum*	27-02-91	97
Local Government Electricity Association* of New South Wales	14-08-90 5-03-91	34 122
Local Government Electricity Supply* Association - Victoria Inc.	2-08-90 1-03-91	11 102
London Economics	4-03-91	110
Meekatharra Minerals Limited	26-11-90 5-04-91 16-04-91	86 150 157
Metal Trades Industry Association of Australia	6-09-90	68
Mount Isa Mines Limited	10-08-90	30
Municipal Officers Association of Australia - SA/NT Branch	6-08-90	15
New England Electricity	4-03-91	115

Participant	Date of Submission	Submission number
New South Wales Chief Secretary & Minister for Water Resources	12-12-90	88
New South Wales Gas Users Group*	1-08-90	32
	24-09-90	77
	3-12-90	87
	28-02-91	108
New South Wales Government*	17-08-90	40
Non-SECV Members of the SECV Residential Advisory Panel	26-02-91	99
Northern Territory Government	29-08-90	58
	9-04-91	153
Penrice Soda Products Pty Ltd	29-08-90	63
	12-03-91	133
Pipeline Authority, The* (TPA)	24-08-90	55
	22-03-91	145
Power Systems Australia	3-08-90	6
Queensland Conservation Council	2-08-90	8
Queensland Government	9-08-90	27
	1-05-91	161
Rainforest Conservation Society*	2-08-90	3
Ravine, Mr Peter	10-09-90	67
Robinson, Dr R. W.	3-09-90	62
Rothschild Australia Corporate Limited	19-04-91	160
SAGASCO Holdings Limited* (SAGASCO)	22-08-90	46
	14-03-91	135
Shell Company of Australia Limited	24-08-90	56
	14-03-91	138
Snowy Mountains Council* (SMC)	8-08-90	24
	11-03-91	136
Snowy Mountains Hydro-Electric*	7-08-90	16
Authority (SMHEA)	26-02-91	96
	18-04-91	158

Participant	Date of Submission	Submission number
South Australian Government*	14-08-90	44
	6-09-90	73
	1-11-90	85
	11-04-91	154
State Electricity Commission of Victoria* (SECV)	6-08-90	21
	17-08-90	47
	11-10-90	82
	13-03-91	132
	15-03-91	137
	11-04-91	155
State Energy Commission of Western Australia (SECWA)*	24-08-90	54
	13-09-90	72
	9-04-91	151
Stewart, Mr E. D. J.	24-03-91	129
Tasmanian Government*	23-08-90	50
	8-03-91	127
Trade Practices Commission	14-05-91	162
Trade Unions in the Electricity Industry	13-11-90	84
prepared by the Public Sector Research Centre University of New South Wales	28-02-91	109
Tumut River Electricity	28-02-91	107
University of New South Wales - Department of Electric Power* Engineering	1-03-91	106
University of Queensland - Division of Mechanical Engineering	1-08-90	7
Urban Development Institute of Australia*	5-03-91	120
Victorian Government	13-03-91	134
Weissmann, Mr Gerhard	22-03-91	143
Western Australian Chamber of Commerce and Industry	20-07-90	23
Western Australian Government	27-08-90	66
	9-04-91	152
Wilkie, Mr Ray - Illawarra Electricity	13-02-91	94

Attachment 1.4: Visits and discussion program

A list of the organisations with which discussions were held, according to location, is provided below.

Adelaide

Department of Industry, Trade and Technology
Electricity Trust of South Australia
Office of Energy Planning
Pipeline Authority of South Australia
SAGASCO Holdings Limited
Santos Limited

Brisbane

Allgas Energy Limited
Department of Economic and Trade Development
Department of Environment and Heritage
Department of Resource Industries
Department of the Premier
Department of the Treasury
Gas Corporation of Queensland Limited
Queensland Electricity Commission

Canberra

Australian Gas Association
Australian Gas Light Company Limited
Esso Australia Resources Limited
Snowy Mountains Hydro-Electric Authority

Darwin

Department of Mines and Energy
Northern Territory Department of Treasury
Northern Territory Gas Pty Limited
Northern Territory Power and Water Authority
Northern Territory Power Pty Limited

Hobart

Australian Newsprint Mills
Department of Premier and Cabinet
Department of Resources and Energy
Department of Treasury and Finance
Hydro-Electric Commission of Tasmania

Melbourne

ACTU Power Group
BHP Pty Ltd
CRA Limited
Department of Environment
Department of Industry and Economic Planning
Department of Premier and Cabinet
Department of Treasury
Electricity Supply Association of Australia
Gas and Fuel Corporation of Victoria
ICI Australia
Pulp and Paper Manufacturers Federation of Australia
State Electricity Commission of Victoria

Perth

Confederation of Western Australian Industry
Department of Treasury
Energy Policy and Planning Bureau, Western Australian Chamber of Commerce and Industry
Minister for Economic Development
State Energy Commission of Western Australia
West Australian Natural Gas Pty Limited

Sydney

Australian Gas Light Company Limited
Department of Minerals and Energy
Electricity Commission of New South Wales
Electricity Council of New South Wales
Intelligent Energy Systems Pty Limited

APPENDIX 2: INDUSTRY STRUCTURE AND MARKETS

The electricity and gas supply industries are significant within the Australian economy with a value added of almost $7 billion and employment of about 90 000 people in 1986-87. Electricity and gas are major components of final energy demand. Demand growth for electricity and gas has outstripped that for other energy sources since the 1970s. This has led to extensive capital investment programs, particularly in the electricity industry. Despite this growth, real prices have remained static in most states since the 1970s.

2.1 Introduction

In this Appendix, information on the nature and extent of the electricity and gas supply industries is provided, including: their role in the overall energy market; markets and industry linkages; likely future demand trends; and industry organisation. Within the gas industry, the focus is on natural gas.

2.2 Electricity, gas and the energy market

The energy sector is comprised of primary and derived forms of energy. Primary forms of energy are drawn directly from nature and include crude oil, coal, natural gas, uranium and renewables such as wood, bagasse, hydro-electricity and solar energy. Natural gas was the third largest source of primary energy in 1989-90, accounting for 17 per cent of total domestic energy consumption. Coal and related products were the major source, supplying 46 per cent of primary needs, followed by petroleum products at 37 per cent.

Derived or secondary forms of energy are produced from primary energy sources, through conversion processes. They include products such as thermal electricity, coke, town gas, briquettes and petroleum products. Energy conversion processes are the largest use of energy in Australia, accounting for 78 per cent of total available primary energy in 1989-90. Of this, only 46 per cent was actually converted to derived energy, the remainder was dissipated in the conversion process itself:

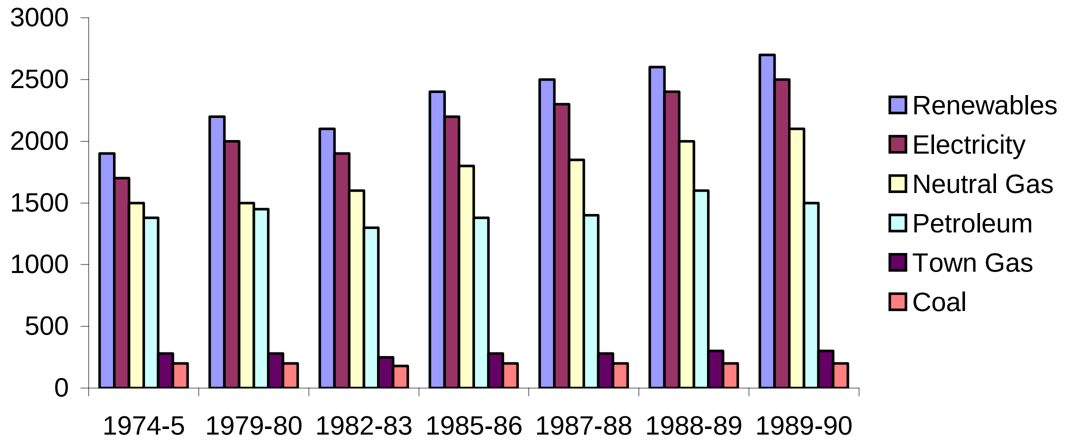
- electricity generation is the largest energy conversion industry. In 1989-90, it accounted for 27 per cent of total energy consumption, 1 489 PJ of energy was used to make 475 PJ of electricity available for end use - an overall energy conversion efficiency of 32 per cent; and

- after the conversion sector, the largest energy using sectors in 1989-90 were transport (26 per cent of total energy consumption), manufacturing (23 per cent), residential (8 per cent), commercial (4 per cent), mining (4 per cent) and agriculture (2 per cent).

Final domestic energy availability is the amount of energy available in Australia for consumption by end users. It is equal to total energy consumption less energy consumed or lost in conversion, transmission and distribution. In 1989-90, final domestic energy availability was 2 664 PJ. This was less than a third of the production of primary fuels, which was 8 922 PJ. Two factors accounted for this difference: losses of energy in conversion processes, mentioned, above and the large energy export sector (ABARE 1991).

Figure 2.1 shows final domestic availability between 1975-76 and 1989-90. Electricity's share of final available energy rose from 11 per cent in 1973-74 to 18 per cent in 1989-90. In the same period, natural gas increased its share from 7 to 19 per cent, and LPG increased from 1 to 3 per cent.

Figure 2.1**: Final Australian domestic energy availability, 1974-75 to 1989-90** (Petajoules)



Source: ABARE (1991) and AGA (1990)

2.2.1 Electricity consumption

The proportion of Australia's primary energy resources used for electricity generation increased from 18 to 27 per cent between 1973-74 and 1989-90 (ABARE 1991).

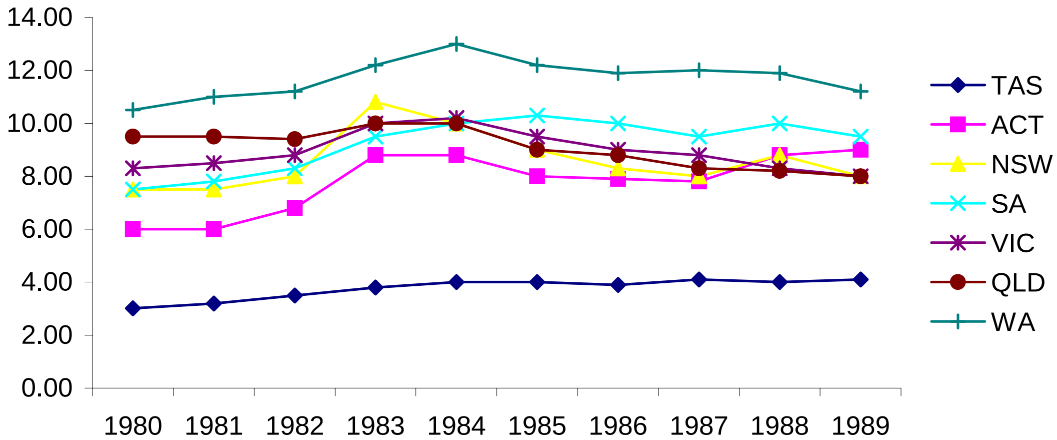
While the overall growth picture for the ESI during this period was strong, the 1973-74 oil shock slowed growth. Additionally, natural gas emerged as an important competitor for electricity at around this time. Other influences on electricity demand growth over this period include:

- population growth and rising real incomes;
- increased penetration of electrical appliances into the household sector; and
- expansion of the industrial sector and the introduction of new electricity-intensive manufacturing technology (DPIE 1986).

The price of electricity

Figure 2.2 shows the real price of electricity for each state/territory since 1980.

Figure 2.2: **Electricity prices 1980-1989**
Unit price (c/kWh, Dec 1988 dollars)



Source: ESAA Annual Reports.

- During the 1980s, Tasmania's hydro-based electricity system achieved the lowest prices by a considerable margin.
- Western Australia had the highest electricity prices during the 1980s.
- Real electricity prices increased in all states, except Queensland, over the period 1980 to 1983. This was primarily due to the effects of the 1982-83 economic recession, which restricted sales of electricity at a time when most states were trying to fund the construction of previously committed new capacity. This was most pronounced in New South Wales where, in 1982-83, average electricity prices increased by around 30 per cent.
- Since 1984, most states have reduced prices in real terms. Despite these reductions, real prices in 1989 were still higher or similar to price levels ten years earlier.
- Queensland was the only state to achieve a significant real price reductions in the ten years to 1989, with average prices falling by 18 per cent.

Markets

In 1989-90, the manufacturing sector accounted for 41 per cent of final domestic consumption, the residential sector 29 per cent and the commercial sector 20 per cent. Electricity is the major energy source for the commercial and residential sectors, and is an important supplier to manufacturing, mining, agriculture and rail transport (ABARE 1991).

Figure 2.3 shows income from electricity sales in each sector by state. New South Wales consumes 35 per cent of Australia's electricity, more than any other state. The other major electricity consuming states are Victoria and Queensland, which consume 25 and 16 per cent respectively. The importance of residential electricity demand ranges from 24 per cent in the Northern Territory to 39 per cent in South Australia (ESAA 1991).

ABS (1988a) figures show that, on average, consumers in Victoria, Tasmania, South Australia and the ACT use more electricity than consumers in other states/territories. In recent years, consumption growth per capita has been greatest in Western Australia, primarily due to the strong performance of the commercial and industrial sectors.

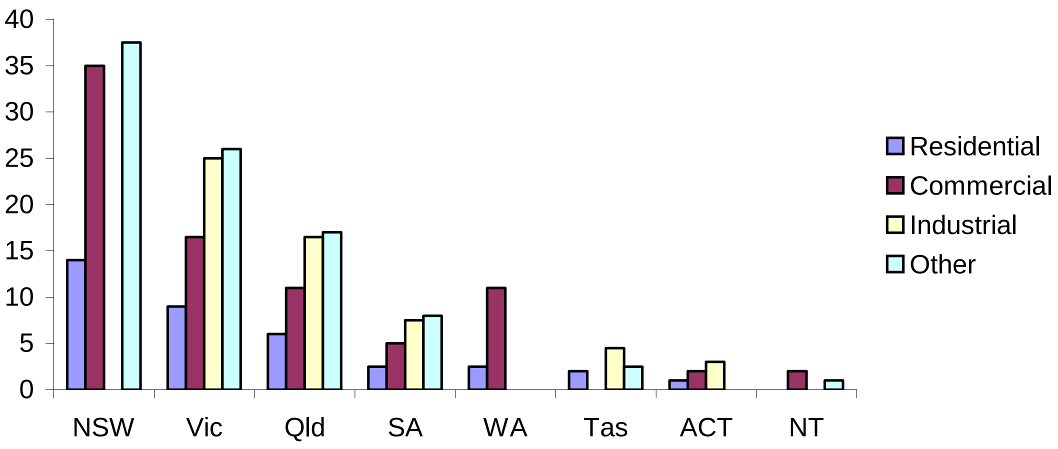
Industry linkages

Attachment 2.1 presents the 20 largest electricity using industries, in relative terms[1]. In 1986-87, electricity represented 1.5 per cent of all inputs into Australian industry. After the ESI itself, the Non-ferrous metals sector was the largest user of electricity - electricity constituted 5.3 per cent of its inputs. Aluminium smelting is a particularly important energy user within this classification.

1 This information is derived from the ABS Input-Output tables. They measure the total supply of commodities, whether locally produced or imported, and show how these commodities were absorbed by industry as intermediate inputs to current production, and by final demand categories.

Other large using industries include Cement and Paper. There are 22 industries which relied on electricity for more than 2 per cent of their factor inputs. In absolute terms, the 20 largest users of electricity consumed almost 80 per cent of the ESI's output (ABS 1990).

Figure 2.3**: Electricity sales by sector and state, 1989-90**
($ billions)



Note: In New South Wales and Western Australia, the commercial and industrial categories are combined.

Source: ESAA Annual Report (1991)

At a more disaggregated level, electricity is used in much larger proportions by some individual users. ABARE (1991) notes that the level of energy consumption in industries depends on the type of manufacturing process utilized rather than their relative size in terms of output, value added or employment. Several participants are significant users of electricity, for example:

- according to CRA, electricity represents about 30 per cent of the operating costs of the average aluminium smelter;

- ICI noted that at, its Botany site, electricity accounts for 16 per cent of total variable costs and up to 64 per cent of the variable costs of a number of individual products; and

- Penrice Soda Products' total energy requirements, which are largely met by electricity, represent 22 per cent of its manufacturing costs. (p.5)

2.2.2 Gas consumption

In value terms, the gas supply industry has an output about one-eighth the size of the ESI. In the fifteen years to 1989-90, natural gas consumption grew at an average annual rate of 9 per cent, making it Australia's fastest growing energy source. LPG consumption growth was also high during this period, averaging over 6 per cent annually, although this was from a small base (ABARE 1991). Two factors combined to increase natural gas consumption levels.

- Improved availability due to the extension of reticulated supply. The development of natural gas fields in South Australia, Queensland and Bass Strait enabled the provision of supply to most south-eastern States. In 1968, Brisbane became the first Australian capital city to receive reticulated natural gas, having been linked to the Surat Basin field. The North-West Shelf discoveries provided natural gas to Perth, so that by 1981 natural gas was available in all mainland capital cities. However, Tasmania remains without natural gas.

- Natural gas enjoyed a considerable price advantage over other energy sources, particularly oil. This resulted in the large scale substitution of natural gas for other forms of energy.

ABARE expects lower growth rates, of around 2.9 per cent a year, for natural gas in the period to 2004-05. According to ABARE, this is because the scope for further reticulation extension is diminishing, major substitution possibilities have largely been embraced and the oil-gas price differential has generally been reduced. Further growth is likely to be closely linked to the extent gas is used for electricity generation.

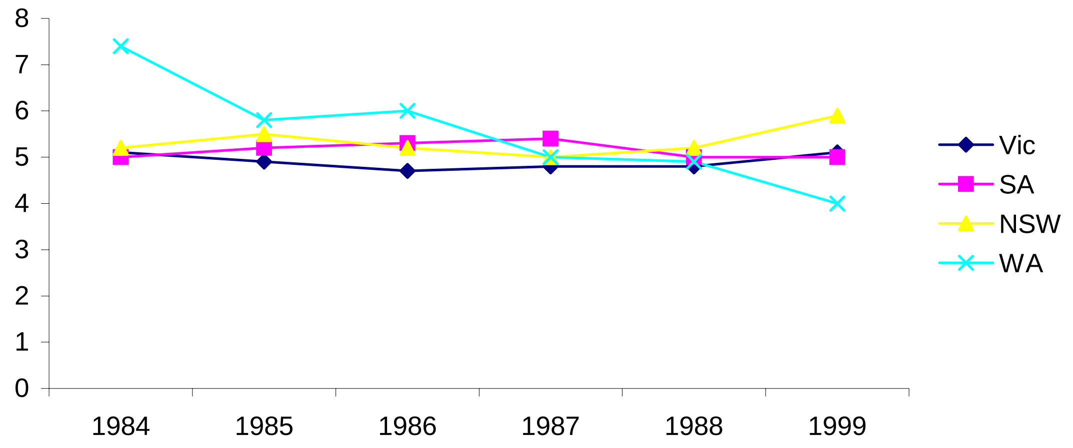
The price of natural gas

There are significant disparities between natural gas prices in different states/territories. Figure 2.4 shows average real gas prices in the four major gas using states for the six years to 1988-89.

- over this period, Western Australian gas prices fell in real terms to be the lowest of the four major gas using states; and

- New South Wales was the only one of the four states in which the price of gas has risen in real terms.

Figure 2.4: **Retail gas prices 1984-1989**
($/GJ, Dec 1988 dollars)



Source: AGA Reports and NSW Department of Minerals and Energy

Markets

The manufacturing sector is the major user of natural gas. In 1989-90, it accounted for some 43 per cent of total domestic availability, followed by electricity generation with 23 per cent, residential use with 12 per cent, mining with 9 per cent and the commercial sector with 5 per cent.

- In 1989-90, natural gas provided 11 per cent of manufacturings' primary inputs, after having increased by around 12 per cent annually since 1978-79. The desirable physical characteristics of natural gas, such as being a clean burning easily controllable fuel, make it well suited to many manufacturing applications. Consequently, natural gas has been substituted for significant quantities of fuel oil.

- Over the period 1973-74 to 1989-90, natural gas increased its contribution to electricity generation from 5 to 16 per cent. The use of natural gas in electricity generation has been boosted since 1984 by the utilisation of North-West Shelf gas for power generation in Western Australia.

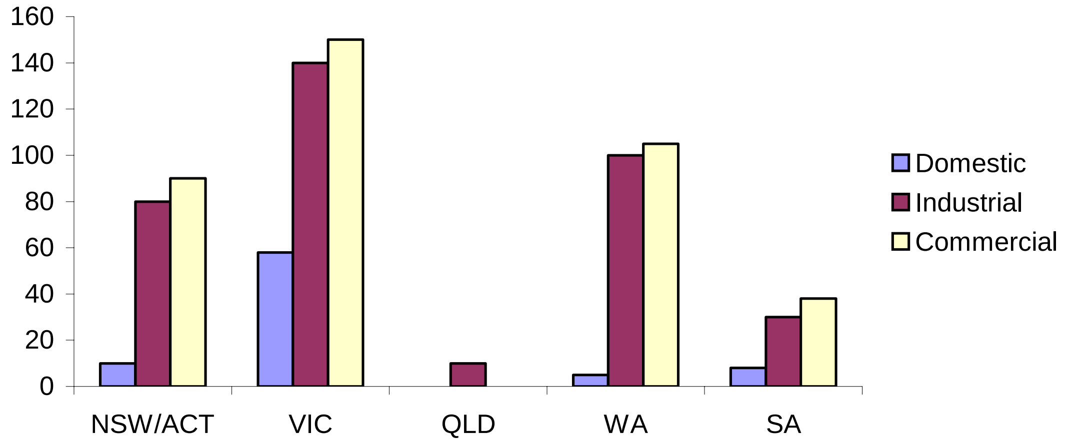
- Although the mining industry is a small user of natural gas in absolute terms, natural gas is the largest energy input into this sector, providing 52 per cent of the sector's energy.

- Natural gas supplies 22 per cent of the energy needs of the commercial sector. This sector more than doubled its usage of natural gas during the 1980s.

- Natural gas provided 27 per cent of residential energy requirements in 1989-90 (AGA 1991). Residential use of natural gas has been influenced by improvements in appliance efficiency as well as the price of gas (AGA 1988).

Figure 2.5 shows consumption patterns of natural gas in different states and territories.

Figure 2.5: **Gas sales by sector and state, 1988-89**
(Petajoules)



Source: AGA (1990)

In 1988-89, Victoria accounted for almost half of Australia's natural gas usage. In that State, 27 per cent of sales were residential and 53 per cent were to manufacturing users. The next largest gas consumer was Western Australia, which consumed 37 per cent of supplies. In contrast to Victoria, 95 per cent of Western Australian natural gas consumption was used industrially, while just 2 per cent was directed to domestic use. Such differences reflect access to reticulation, physical differences between States, regulatory policy, and relative pricing. For example, Victoria had a well developed town gas reticulation network based on local coal supplies before the introduction of natural gas. In Western Australia this was not the case, due to the absence of abundant local coal supplies.

The major market for LPG is the transport sector which, in 1988-89, accounted for 24 per cent of consumption (AGA 1990). The use of LPG in the transport sector has grown rapidly. The residential sector accounted for 11 per cent of LPG consumption 1988-89. LPG is delivered in cylinders to households in less densely populated regions where it is not economic to reticulate natural gas. In some areas, tempered LPG is reticulated to home users.

Industry linkages

Attachment 2.2 shows the 20 industries which used gas most intensively in 1986-87. In this period, natural gas made up, on average, 0.4 per cent of the value of inputs for Australian industry. More than 6 per cent of the Clay products industry's inputs came from natural gas, making it the most intensive gas using industry. In absolute terms, the two largest using industries were the ESI and the Non-ferrous metals industries, each of which consumed some 20 per cent of natural gas output. Fifteen other industries consumed more than one per cent of industry output.

As in the case of electricity, some individual users consume much larger proportions of natural gas in their production process. For example, Incitec noted that:

> ...natural gas and electricity are the major cost components in the manufacture of ammonia and urea, comprising over 80% of the variable cost. The cost of supply and distribution of these two factors are of great importance to the nitrogen industry in Australia. (Incitec, p.5)

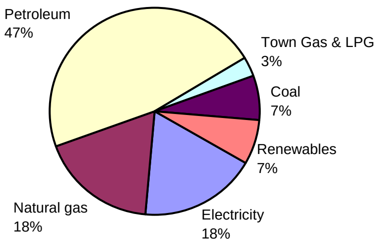
2.3 Future energy developments

Considerable effort has been devoted to demand forecasting in the energy sector. The high costs attendant on inappropriate or ill-timed investment on expensive energy capital projects provides an incentive for accuracy in forecasting. Demand forecasts tend to make assumptions about the nature and extent of likely future levels of economic growth and price movements which would influence future energy demand. For example, strong growth in energy intensive sectors such as manufacturing imply greater increases in energy consumption. Factors which influence forecasts include economic activity, population, technological developments and relative prices.

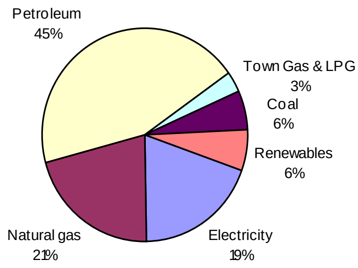
ABARE (1991,p.14) has projected a growth in final energy consumption of 2.2 per cent annually over the period 1989-90 to 2004-05. However, towards the end of this period the rate of growth of total energy consumption is projected to decline to around 1.7 per cent, with a return to the historical downward trend in the energy intensity of the economy. High past rates of growth are not expected to be repeated as energy substitution and cost reduction possibilities have largely been realised.

Figure 2.6 shows the components of final energy demand in 1989-90, and forecast demand for 2004-05. Electricity, natural gas and LPG are forecast to increase their share of final energy availability in this period, at the expense of all other energy sources.

Figure 2.6: **Forecast fuel shares, final energy demand, 1989-90 and 2004-05**
(per cent)



1989-90



2004-05

Source: ABARE (1991)

2.3.1 Electricity

ABARE (1991) has forecast that the share of electricity in final energy consumption will increase at an average rate of 2.8 per cent a year until 2004-05. This is close to half the annual growth rate of 5 per cent experienced in the decade to 1985. Even so, under this scenario electricity would increase its share of final domestic energy availability from the 1989-90 level of 17.8 per cent to 19.1 per cent. Additionally:

- over the period to 2004-05, ABARE projects growth in electricity consumption to average 2.6 per cent a year;
- overall electricity generation conversion efficiency is projected to increase from 32.4 per cent in 1989-90 to 34.5 per cent in 2004-05, because a greater proportion of new capacity is anticipated to be more efficient combined-cycle plant and because of the retirement of obsolete plant;
- the shares of natural gas and black coal in the energy inputs to thermal generation are projected to increase from 11 and 58 per cent, respectively, in 1989-90 to 13 and 63 per cent in 2004-05. The share of brown coal is anticipated to decline from 29 to 23 per cent; and
- the fastest growth in electricity consumption is projected to occur in the commercial sector, with 3.8 per cent annual growth.

2.3.2 Gas

ABARE has forecast that growth in natural gas consumption will moderate over the period to 2004-05, with an annual average growth of 3.2 per cent a year, compared to 9 per cent over the last fifteen years. By 2004-05, natural gas is expected to account for 19.6 per cent of final energy consumption, as compared with 17.4 per cent in 1989-90. Additionally:

- manufacturing industry is expected to remain the largest market for natural gas, but its share of consumption is expected to decline as consumption in other sectors grows at a faster rate;
- growth in the use of natural gas in electricity generation is projected to be rapid, averaging 3.5 per cent annually over the projection period; and
- natural gas is projected to replace LPG as the fastest growing road transport fuel in the period to 2004-05, by which time it is expected to account for 2.9 per cent of the transport market.

ABARE projects LPG consumption to grow by 2.7 per cent a year to 2004-05. This is despite lower availability of natural LPG from domestic sources. Consumption growth is expected to be concentrated in the major industrial centres where competition amongst distributors is highest. LPG is expected to increase its share of the transport market from 2.3 per cent to 3.1 per cent by 2004-05.

The 1988 AGA report Gas Supply and Demand to 2030 forecast somewhat lower growth rates for natural gas. Its base forecast for the period 1989-90 to 2009-10 is 1.8 per cent. The AGA (1988) considered that two new developments have the potential to alter the gas market significantly:

- The development of natural gas powered vehicles is currently the subject of considerable research. Estimates of the size of this market range up to 70 PJ per annum by the year 2000, equivalent to 11 per cent of total demand in 1987-88.
- The development of further major petrochemical plants. A typical plant would use up to 20 PJ of gas. Additionally, there are large plants where replacement of oil by gas may occur with significant effects on gas demand, notably the Gove alumina refinery and the Mt Isa power station.

2.4 Key features of the electricity and natural gas supply industries

2.4.1 Industry size

In 1986-87, the electricity and gas supply industries together accounted for 2.6 per cent of Australia's gross domestic product, employed 90 000 persons and supplied over 36 per cent of Australia's final energy requirements. Table 2.1 provides details of the size of the two industries between 1971-72 and 1986-87.

The ESI is one of Australia's largest industries. In 1986-87, value added was of the order of $5.9 billion. This was over double that of other large Australian manufacturing industries, such as clothing and footwear, the motor vehicle and the basic iron and steel industries (ABS 1988c).

Table 2.1**: Selected data on electricity and gas establishments, 1971-71 to 1986-87**
($ million)

	Year						
	71-72	*79-80*	*80-81*	*82-83*	*83-84*	*84-85*	*86-87*
Electricity							
Employment (persons)	67 145	70 970	72 470	82 328	82 673	82 611	78 594
Wages and Salaries	363.2	965.3	1 139.2	1 689.6	1 823.7	2 000.8	2 179.3
Value Added	920.9	2 499.9	3 041.1	4 192.3	4 716.5	4 856.3	5 876.3
Turnover	1 504.3	4 740.1	5 621.1	8 343.3	9 342.0	10 154.4	12 041.4
Gas							
Employment (persons)	8707	9894	9998	10584	10544	10 517	11107
Wages and Salaries	41.3	130.5	151.0	206.4	217.9	229.4	274.0
Value Added	91.1	343.9	410.7	626.0	752.0	825.0	1 042.0
Turnover	147.7	564.3	692.9	1 158.1	1 386.4	1 655.2	1 985.8

Sources: ABS 1989a (various issues).

2.4.2 Electricity generation, transmission and distribution

Both the electricity and natural gas supply industries can be divided into three segments - production (generation), transmission and distribution. In the ESI, the share of total cost assumed by each of these three activities is in the order of 65 per cent for generation, 10 per cent for transmission and 25 per cent for distribution. Capital costs account for some 50 per cent of total costs, with labour and fuel costs accounting for 15 and 20 per cent respectively (Lawrence et.al. 1990).

Generation

Electricity generation is the conversion of naturally occurring energy sources into electricity.

Electricity generation in Australia is primarily the responsibility of public authorities at state/territory level, which account for more than 90 per cent of all electricity generated. There are nine electricity authorities, including those in the two Territories and the Snowy Mountains Hydro-Electric Authority.[2]

Private generation is chiefly undertaken by the manufacturing and mining industries. Smaller generation facilities using waste products as fuels are operated by a number of other industries, for example sugar mills and coal mines. Some sell part of their output to government electricity utilities or, in some cases, directly to final users. Additionally, there are also examples of private electricity supply to the public:

- remote mining towns are generally supplied by private generators associated with mining and minerals processing works. In some cases, cogeneration plant has been installed;
- in New South Wales, the Eraring power station was sold to a partnership of Australian companies in 1982. However, ownership will eventually revert to ECNSW, and the station has little autonomy as it is operated and maintained by ECNSW, which also purchases all the output; and
- in Western Australia, the small Pilbara Grid is supplied by private power stations operating primarily for mining operations. Additionally, the planned Collie coal-fired station is to be constructed, owned and operated by a private consortium.

Installed generating capacity grew at an average annual rate of nine per cent from 1963-64 to 1973-74, by five per cent between 1974-74 and 1983-84, and by four per cent between 1983-85 and 1988-89. New South Wales has more than one third of Australia's installed capacity, equal to almost twice that of the next largest state, Victoria. Table 2.2 shows the generating capacity in each state.

Several factors influence the choice of generation method, including fuel source availability and the capital cost of constructing generating plants. These factors have favoured the construction of large plants adjacent to coal-fields since, with the development of high voltage transmission technology, electricity transmission is significantly cheaper than the haulage of fuel.

2 That is, the Electricity Commission of New South Wales, the Queensland Electricity Commission, the State Electricity Commission of Victoria, the State Energy Commission of Western Australia, The Electricity Trust of South Australia, the Tasmanian Hydro-Electric Commission, the Northern Territory Power and Water Authority, the Snowy Mountains Hydro-Electric Authority and the ACT Electricity and Water Authority.

Table 2.2: **Characteristics of the ESI, 1989-1990**

	NSW	*VIC*	*QLD*	*SA*	*WA*	*TAS*	*NT*	*SMA*[b]	*AUS*
Inst Capacity (MW)	11 443	6 654	5 098	2 368	2 464	2 320	348	3 740	34 435
Output (GWh)	48 861	35 762	25 355	8 861	9 990	9 034	1 053	4 306	142 693
Sales Revenue ($mil)	3 897	2 581	1 675	782	1 038	361	132	-	10 465
Customers ('000)	2 527	1 876	1 162	665	623	219	44	-	7 118
Sales/Employee ($'000)	167	145	196	150	159	97	183	-	159

a Includes ACT.
b Snowy Mountains Hydro-Electric Authority.
Source: ESAA (1991).

Electricity cannot be effectively stored in large quantities, and so must be produced to satisfy instantaneous demand. Additionally, demand fluctuates both daily and seasonally with the varying demands of industry, commerce and residential users.

Within this variation there is an underlying constant load, or 'base load'. This is supplied by larger generating plant designed to operate most economically at constant output, and which obtain low marginal cost. 'Intermediate' and 'peak' demands are met by generating plants with successively higher marginal running costs:

- In Australia, coal-fired steam plants are primarily used for base load generation. Steam generation accounts for 74 per cent of electricity production in Australia, and is responsible for base load generation in all states except Tasmania and the Northern Territory. The primary fuel for this generation process is coal which, in 1989-90, supplied about 84 per cent of requirements (ABARE 1991).

- There are 32 steam generating plants operating in Australia, 11 of which have a total capacity above 1000 MW. Individual units range in size up to 660 MW. The two largest New South Wales plants, Eraring and Bayswater, each have total capacities of 2640 MW. This is greater than the entire generating capability of either South Australia or Western Australia.

- Gas turbine combustion accounts for only about four per cent of Australia's electricity generation, but is relatively important in Western Australia, South Australia and the Northern Territory. It supplies more than half of the Northern Territory's electricity requirements.

- The Channel Island power station in the Northern Territory is Australia's only operating combined-cycle plant. It also incorporates open cycle gas turbines, and is the largest plant operating in the Territory.

- The abundance of appropriate resources in Tasmania has led to hydro-electricity being the major generation method in that state. In most years it is responsible for 93 per cent of all electricity generation, and caters for both base and peak demand.

- On the mainland, the Snowy Mountains scheme (3740 MW) is the largest hydro installation, although there is some 1 400 MW installed elsewhere in New South Wales, Victoria and Queensland. The lower plant utilization associated with peak-load usage, and the variability of natural conditions, results in hydro power contributing about 11 per cent to total electricity generation in Australia, even though it represents some 21 per cent of installed capacity (DPIE 1986).

Primary fuel sources

Primary energy usage by the ESI is outlined in Table 2.3. Coal is the major fuel for electricity production. It accounts for around 84 per cent of energy inputs into the industry. Oil is used to some extent in all states, but usually only for starting up purposes or for generation in remote, sparsely populated areas supplied from diesel generators.

In most states, some natural gas plant is used to satisfy intermediate and peak loads. In recent years it has become an important fuel input for base load power in South Australia, Western Australia and the Northern Territory. The importance of natural gas in Western Australia arose due to the over-supply of primary fuels (natural gas and black coal). This over-supply was managed by stockpiling coal and using natural gas from the North West Shelf under a take-or-pay contract. In the Northern Territory, it is estimated that by the turn of the century virtually all electricity will be generated by natural gas.

Table 2.3: **Electrical energy generated from resources, 1988-89**
(per cent of energy)

	NSW	*VIC*	*QLD*	*SA*	*WA*	*TAS*	*AUS*
Black Coal	33.6	-	16.7	-	4.4	-	54.7
Brown Coal	-	22.9	-	2.6	-	-	25.4
Oil	-	-	-	-	0.5	0.1	0.6
Gas	-	1.6	-	4.0	2.2	-	8.5[a]
Hydro	2.1	1.7	0.6	-	-	6.4	10.8
Total	35.7	26.2	17.3	6.5	7.1	6.5	100.0

a Includes 0.7 from the Northern Territory.
b Energy produced by the Snowy Scheme has been allocated to New South Wales and Victoria. The hydro figure for New South Wales includes energy used in the Australian Capital Territory.
Source: ESAA (1991).

Planned increments to capacity

Increments to generating capacity can be achieved through the addition of new generating plant or extending the life of existing plant:

- In New South Wales, work is underway on the 1320 MW (2x660 MW) Mount Piper Power station west of Lithgow. Beyond this, consideration is being given to the construction of a privately owned 2800 MW (4x700 MW) base load station at Oaklands near Wagga, which would be Australia's largest power station. Several life extension and rehabilitation programs are being considered for other stations.

- The first 500 MW unit of the Loy Yang B station in Victoria is anticipated to come on line in 1992. A second unit is under construction, while the future of the planned third and fourth units is uncertain. The SECV wishes to sell the station to private interests.

- In Queensland, the final 350 MW generating unit of the Callide B station was commissioned in March 1989. Construction has commenced on the Stanwell station (4x350 MW), near Rockhampton. Beyond this, approval is being sought for a hydro station at Mount Tully, between Tully and Ravenshoe.

- The South Australian Government is considering alternatives to a third (250 MW) coal-fired unit at the Northern Station in Port Augusta, including a combined-cycle plant or extension of the interconnection with Victoria. (Adelaide Advertiser, 1/2/91, p.4)

- In Western Australia, a 300 MW (3x100) combined cycle plant is to be constructed at Pinjar, north of Perth, with units coming on line from the end of 1991. This will complement recently completed low-capacity peak load gas turbines on the same site. Following this, a privately built, owned and operated coal-fired power station (2x300 MW) is to be built at Collie, in the state's south-west. The station is scheduled for completion in 1997. (Engineers Australia, 25/1/91, p.28)

- In Tasmania, the 144 MW King River Hydro Power Station is scheduled for completion in early 1992, and the 82.8 MW Anthony Power Development in mid-1994.

- In the Snowy Mountains Scheme, a refurbishment and redevelopment program is underway to improve the capability of plant at Tumut 1 and Tumut 2.

- A number of states are encouraging cogeneration (see Appendix 7).

Transmission

Electricity transmission systems transfer electricity from the point of generation to near the point of final demand. They also enable the interconnection of supply centres to create large networks. Scale economies can be realised through the operation of optimally sized supply units. Scale economies also arise from two other characteristics of electricity transmission:

- it is more energy efficient to transmit electricity along a single line at high voltage and low current, than along several lower voltage lines; and

- electricity transmission involves high sunk costs but low incremental variable costs, so that for a given capacity it is cheaper to have a single system.

For these reasons, electricity transmission is generally considered to exhibit the characteristics of a natural monopoly.

Electricity transmission involves energy losses due to heating of conductors. As this loss is proportional to length, it is a factor which must be considered when designing systems to cover long transmission distances. The amount of deliverable electricity for single high voltage transmission lines, over the long distances characteristic of Australia, can be considerably less than the amount generated. Other important factors in long-distance transmission are transient and oscillatory instability problems. These are usually the determining condition for the amount of opportunity interchange within and between Australian utilities, where there are long distances between concentrations of generation.

Important features of electricity transmission in Australia include the following:

- Interstate transmission links are presently confined to those between Victoria and both New South Wales and South Australia. The New South Wales-Victoria link is centred on the Snowy Mountains Scheme, although there are other connections. The Victoria-South Australia link was commissioned in March 1990 and has a nominal capacity of 500 MW to South Australia and 250 MW to Victoria.

- In 1989-90, the state with the largest transmission system was Victoria, with 6 352 km circuit kilometres installed, followed by New South Wales (5 859 km), Queensland (4 229 km), South Australia (2 410 km) and Western Australia (1 401 km) (ESAA 1991).

- Public transmission networks in Australia are largely owned by state electricity utilities. However, there are significant exceptions to this, including the privately owned Darwin to Katherine link, Hammersly Iron's Pilbara grid and Alcoa's 200 kV line between Pt Henry and Anglesea.

Distribution

Electricity distribution describes the lower voltage electricity supply to consumers. In Australia, power lines of 132kV and lower are generally classified as distribution, except in country areas where the limit is lower. Distribution is carried out at lower voltages than transmission to enable smaller quantities of electricity to be handled efficiently and economically.

In three states, electricity distribution is undertaken separately from transmission and generation (see Attachment 2.3):

- in New South Wales, 25 local government authorities are responsible for electricity distribution. They supply electricity to 97 per cent of the population. In December 1990, legislation was passed for the largest of these authorities, Sydney Electricity, to become a state corporation;

- in Queensland, electricity distribution falls under the jurisdiction of seven regional Electricity Boards, although all are subject to control by QEC;

- the SECV oversees 80 per cent of electricity distribution in Victoria, the remainder being distributed by 11 Municipal Electricity Undertakings.

Within the ACT, ACTEW is responsible for electricity distribution. The ACT is entitled to 13 per cent of the Snowy Mountains Scheme's output. This provides 30 per cent of ACT's electricity, with the balance of demand being met by purchases from ECNSW.

2.4.3 Natural gas production, transmission and reticulation

Production costs for natural gas are low because it requires little refining from its natural state. It is a primary energy source and does not necessitate the energy conversion process characteristic of electricity. Apart from the exports of LNG from the North West Shelf[3], Australia's natural gas is not traded internationally.

Table 2.4 provides details of natural gas utility operations in each Australian state (see also Attachment 2.4).

Table 2.4: **Natural gas production and sales in Australia, 1988-89**
(Petajoules)

	NSW	*VIC*	*QLD*	*WA*	*SA*	*NT*	*AUS*
Net production	0.0[a]	190.7	20.4	146.6	183.4	10.8	551.8
State trade & exports	95.5	0.0	0.0	-3.2	-05.5	0.0	-3.2
Miscellaneous[b]	7.2	5.2	0.8	1.7	3.0	0.3	17.9
Total sales	88.5	185.5	19.6	141.6	85.0	10.5	530.7
Total revenue ($m)	492	707	69	377	133	0.4	0.4
Customers ('000)	533	1 138	116	224	262	-	2 275

a Estimated as a residual after deducting from production gas sold.
b This component is estimated and may include gas used for fuel for pipeline compressors, utilities own use, reforming losses and unaccounted for gas.
Source: AGA (1990)

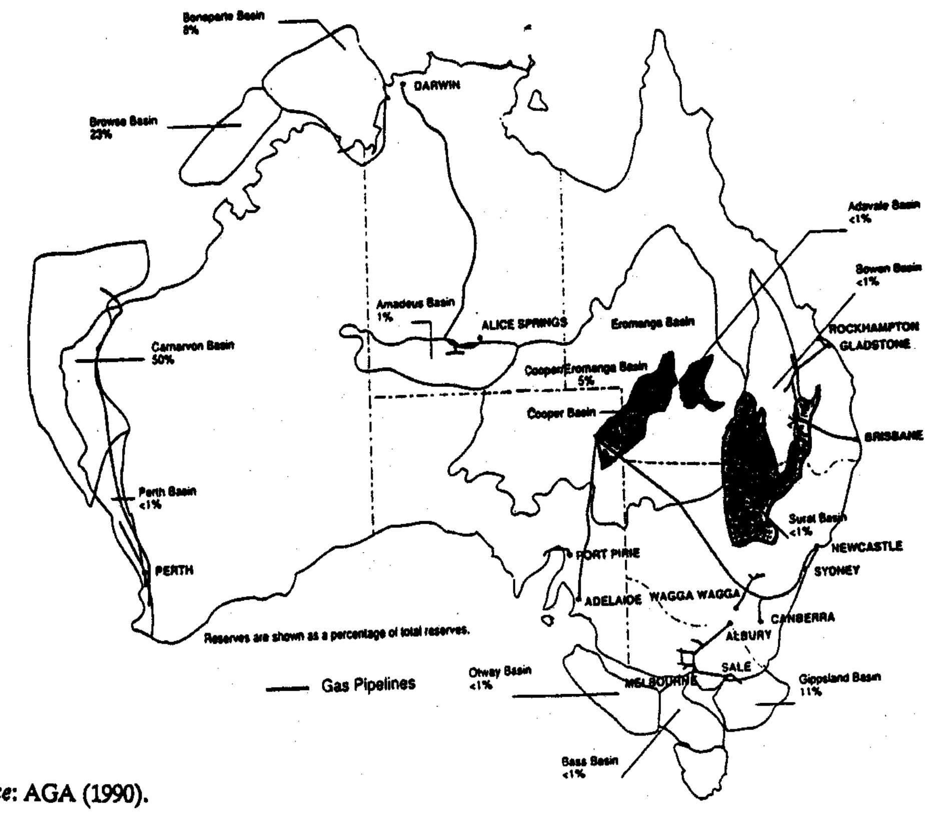
3 Limited international trade in natural gas is not peculiar to Australia. Over 85 per cent of global consumption of natural gas is indigenously sourced (Ball 1989).

Production

Australia's estimated total demonstrated economic resources[4] of natural gas are sufficient to meet current levels of demand for over 50 years. This estimate is likely to be conservative as a great deal of Australia's natural gas resources have been discovered as a by-product of oil exploration rather than by specific exploration for gas.

Most oil and gas exploration and production in Australia is undertaken by the private sector, frequently through joint venture arrangements. In some states, the gas reticulation utility, through an associated company, is involved in exploration and/or production. Figure 2.7 identifies Australia's major gas bearing basins and their contribution to demonstrated natural gas resources, as well as major gas transmission pipelines.

Figure 2.7: **Natural gas resources and pipelines in Australia**



Source: AGA (1990).

4 The Bureau of Mineral Resources judges demonstrated economic resources to be those that are economically extractable. The quality and quantity are computed partly from specific measurements and partly from extrapolation based on geological evidence.

- Over 80 per cent of Australia's reserves occur off-shore in the northern parts of Western Australia and the Northern Territory. Production from this area is presently restricted to the Carnarvon Basin which supplies Western Australia's gas requirements and LNG export markets.
- Victoria is supplied from off-shore reserves in Bass Strait. The remaining mainland states and territories are supplied from smaller on-shore basins.
- Reserves in other states are significantly lower than expected future demand. The South Australian sections of the Cooper/Eromanga Basins have sufficient reserves to meet contractual arrangements for New South Wales until 2006 and for South Australia until at around 1994.

Transmission

Gas transportation mediums include pipelines, LNG tankers and conversion into methanol[5] In most instances, pipelines are the preferred mode due to their relatively lower capital requirements and operating costs. However, the choice of transport mode is essentially determined by natural obstacles (eg distance from shore) and the proximity of gas basins to users.

Natural gas is generally transported within Australia by pipeline[6]. The pipeline network is illustrated in Figure 2.3 (see also Attachment 2.5). All mainland states and territories, except New South Wales and the Australian Capital Territory, are currently supplied from fields within their boundaries. Apart from Queensland, the supply of gas relies on a single transmission pipeline in all states. Information regarding existing and possible interstate trade in natural gas is provided in Appendix 6.

The ownership of natural gas pipelines contrasts sharply with that of other major pipelines transporting crude oil and LPG. The latter are all privately owned (see Attachment 2.5). In Victoria, South Australia and Western Australia, the transmission network is publicly owned and operated by State government utilities. In New South Wales and the Australian Capital Territory, the network is owned and operated by a Commonwealth statutory authority, TPA[7] In Queensland, the transmission network supplying Brisbane is privately owned and operated. The new pipeline between Gladstone and Rockhampton is publicly owned, but privately operated.

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[5] If pipelines are used, the gas is transported in its gaseous state. Transport by LNG tanker requires the gas to undergo a complex compression and refrigeration process (which is often powered by natural gas) before transport. A regasification process is required after transport and before use.

[6] Although the LNG process is not used to transport natural gas within Australia it is used in Victoria to store natural gas for peak periods. A LNG processing plant operates in Western Australia to facilitate the export of North-West Shelf natural gas to Japan.

[7] The Commonwealth Government invited expressions of interest for the sale of all or part of this pipeline system. However, the Bill for the pipeline's sale was denied passage in the 1990 Budget Session of Parliament. The pipeline has subsequently been withdrawn from sale.

The Northern Territory Government has a small amount of equity in the private company which owns and operates the transmission pipeline to Darwin.

Distribution

Once natural gas reaches the city gate it is either supplied directly by the transmitter to large volume customers or distributed by a gas utility to other customers. Natural gas or tempered natural gas accounts for virtually all gas distributed.

Victoria is the largest user of distributed natural gas followed by New South Wales-Australian Capital Territory and Western Australia. Collectively these regions account for over 90 per cent of Australia's gas distribution.

Some key characteristics of the major gas distribution utilities are presented in Attachment 2.4.

- Western Australia and Victoria are the only states where natural gas transmission and distribution are undertaken by fully integrated utilities. SECWA is totally government owned while the GFCV has a 28 per cent private shareholding.
- In New South Wales, the Australia Capital Territory and Queensland, distribution is undertaken by private utilities.
- In South Australia, the State government holds 79 per cent of the share capital in SAGASCO Holdings which operates the South Australian Gas Company (Sagasco).

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Attachment 2.1: Electricity input into industry[ab], 1986-87

Industry	*Electricity Usage*	*Total Resource Usage*	*Electricity as a proportion of inputs*
	($m)	*($m)*	*(%)*
Non-ferrous metals	403.2	7558.5	5.3
Cement	36.7	692.4	5.3
Pulp, paper, paperboard	74.8	1484.7	5.0
Public administration	506.9	11947.5	4.2
Clay products, refractories	31.3	861	3.6
Veneers, mfd. Wood boards	19.1	563.4	3.4
Non-ferrous metal ores	144	4567.5	3.2
Business services nec	673.7	23270.9	2.9
Basic iron and steel	176.2	6360.4	2.8
Railways, transport nec	110.9	4.48.6	2.7
Repairs nec	48.5	1799.2	2.7
Milk, cattle and pigs	54.3	2029.6	2.7
Basic chemicals nec	85.3	3194.5	2.7
Services to transport	85.3	3194.5	2.7
Glass and glass products	18.8	759.7	2.5
Water, sewerage, drainage	77.3	3243.3	2.4
Ferrous metal ores	41.8	1919.3	2.2
Restaurants, hotels, clubs	188.1	8759.2	2.1
Health	382.5	17812.3	2.1
Paper products nec	11.3	532.3	2.1

[a] This table is derived from the input-output tables of the Australian national accounts. It shows how electricity was absorbed by industries as intermediate inputs to current production.
[b] Excluding the electricity industry's own use of electricity, which was $2 879.3 million, or 25.0 per cent of inputs.
Source: ABS (1990).

Attachment 2.2: Gas input into industry[ab], 1986-87

Industry	*Gas Usage*	*Total Resource Usage*	*Natural gas as a proportion of inputs*
	($m)	*($m)*	*(%)*
Clay products, refractories	55.3	861	6.4
Glass and glass products	27.3	759.7	3.6
Cement	22.5	692.4	3.2
Non-ferrous metals etc	222.5	7558.5	2.9
Non-metallic min products	16.6	606.9	2.7
Electricity	248.5	11502.1	2.2
Paper, pulp, paperboard	24.5	1484.7	1.7
Chemical fertilisers	14.1	887	1.6
Basic chemicals nec	37.0	3194.5	1.2
Textile finishing	4.1	363.8	1.1
Basic iron and steel	66.8	6360.4	1.1
Beer and malt	11.2	1576.5	0.7
Veneers, mfd. wood boards	3.6	563.4	0.6
Margarine, oils, fats nec	4.3	723.5	0.6
Breads, cakes, biscuits	10.2	1935.3	0.5
Wool, worsted fabrics etc	1.5	304.4	0.5
Man-made fibres etc	2.8	577.2	0.5
Rubber products	4.4	918.9	0.5
Paper products nec	2.0	532.3	0.4
Fruit, vegetable products	4.6	1280.0	0.4

[a] This table is derived from the input-output tables of the Australian national accounts, and shows how gas was absorbed by industries as intermediate inputs to current production. It shows aggregate gas consumption, as no figures for natural gas alone are available.
[b.]Excluding the gas industry's own use of gas, which was $1.4 million, or 0.1 per cent of inputs.
Source: ABS (1990).

Attachment 2.3: Characteristics of electricity generation, transmission and distribution utilities by state/territory

GENERATION AND TRANSMISSION

	New South Wales	*Victoria*	*Queensland*	*South Australia*	*Western Australia*	*Northern Territory*
Principal Utility	The Electricity Commission of New South Wales	State Electricity Commission of Victoria	Queensland Electricity Commission	Electricity Trust of South Australia	State Energy Commission of Western Australia	Power and Water Authority
Ownership (sector)	Public	Public	Public	Public	Public	Public
Equity	New South Wales Government 100%	Victorian Government 100%	Queensland Government 100%	South Australian Government 100%	Western Australian Government 100%	Northern Territory Government 100%
Integration	Generation and transmission	Generation, transmission and distribution	Generation and transmission	Generation, transmission and distribution	Generation, transmission and distribution	Generation, transmission and distribution

DISTRIBUTION

	New South Wales	*Victoria*	*Queensland*	*South Australia*	*Western Australia*	*Northern Territory*
Principal Utility(s)	County Councils (24) & sydney Electricity	Municipal Electricity Undertakings (11) (a)	Electricity Boards (7)	Distribution undertaken by integrated authority	Distribution undertaken by integrated authority	Distribution undertaken by integrated authority
Ownership (sector)	Public	Public	Public	Public	Public	Public
Equity	Respective Municipal Councils 100%	Respective Municipal Undertakings 100%	State Government 100%			
Integration	Distribution	Distribution	Distribution			

(a) In Victoria 80% of electricity distribution is undertaken by SECV, with the remainder the responsibility of the Municipal Electricity Undertakings

Source: Utilities Annual Reports and relevant legislation

GENERATION AND TRANSMISSION

	Tasmania	*Australian Capital Territory*	*Commonwealth*
Principal Utility(s)	Hydro-Electricity Commission	No generation or transmission undertaken within the ACT	Snowy Mountains Hydro-Electric Authority
Ownership (sector)	Public		Public
Equity	Tasmanian Government 100%		Commonwealth Government 100%
Integration	Generation, transmission and distribution		Generation

DISTRIBUTION

	Tasmania	*Australian Capital Territory*
Principal Utility(s)	Distribution undertaken by integrated authority	ACT Electricity and Water
Ownership (sector)		Public
Equity		ACT Government 100%
Integration		

Source: Utilities Annual Reports and relevant legislation

Attachment 2.4: Characteristics of major natural gas transmission and reticulation utilities by state/territory

TRANSMISSION

	New South Wales and Australian Capital Territory	*Victoria*	*Queensland*	*South Australia*	*Western Australia*	*Northern Territory*
Principal Utility	The pipeline Authority	Gas and Fuel Corporation of Victoria	AGL Petroleum & Qld Government	Pipelines Authority of South Australia	State Energy Commission of Western Australia	NT Gas Pty Ltd
Ownership (sector)	Public	Mixed	Private	Public	Public	Private
Equity	Commonwealth Government 100%	Victorian Government 72% Private 28%	Australian Gas Light Co. & Qld Government own 100% of respective pipelines	South Australian Government 100%	Western Australian Government 100%	NT Gas Pty Ltd 96% Northern Territory Government 4%
Integration	None	Exploration, transmission & reticulation	Production and transmission	None	Transmission and reticulation	None

RETICULATION (a)

	New South Wales	*Victoria*	*Queensland*	*South Australia*	*Western Australia*	*Australian Capital Territory*
Principal Utility	Australian Gas Light Company Ltd	Gas and Fuel Corporation of Victoria	Gas Corporation of Qld and Aligas Energy Ltd	South Australian Gas Company Limited	State Energy Commission of Western Australia	Australian Gas Light Company Limited
Ownership (sector)	Private	Mixed	Private	Public/Private	Public	Private
Equity	Private 100%	Victorian Government 72% Private 28%	Private 100%	South Australian Government 79%, Private 21%	Western Australian Government 100%	Private 100%
Integration	Exploration, production, intrastate transmission and reticulation	Exploration, transmission & reticulation, Production undertaken on a small scale	Reticulation	Exploration, production & Reticulation	Transmission and reticulation	Exploration, production and reticulation

(a) A small amount of natural gas is reticulated in Alice Springs. Natural gas is not reticulated in Darwin. A private utility in Launceston reticulates small quantities of LPG.
Source: Utilities Annual Reports and relevant legislation

Attachment 2.5: Selected on-shore natural gas pipelines[a]

Origin/site	*Destination*	*Length (km)*	*Ownership/operator*[b]
Palm Valley N.T.	Darwin N.T.	1512	NT Gas Pty Ltd [d](P/G)
Mereenie N.T.	Tylers Pass N.T.	116	NT Gas Pty Ltd [d](P/G)
Palm Valley N.T.	Alice Springs N.T.	145	TNT Bulkships Operations Pty Ltd (P)
Silver Springs Qld	Roma QLD	102	Bridge Oil Ltd (P)
Roma Qld	Brisbane QLD	434	AGL Petroleum Pty Ltd (P)
Karratha W.A.	Pt. Lambert W.A.	57	Cliffs Robe River (P)
Gascoyne Junction W.A.	Carnarvon W.A.	170	State Energy Commission of Western Aust. (G)
Wagerup W.A.	Bunbury W.A.	59	State Energy Commission of Western Aust. (G)
Dampier W.A.	Perth-Wagerup W.A.	1482	State Energy Commission of Western Aust. (G)
Dongara (Freemantle) W.A.	Pinjarra W.A.	445	W.A. National Gas Pty Ltd (P)
Tirrawarra S.A.	Moomba S.A.	49	Santos Ltd (P)
Daralingie S.A.	Moomba S.A.	44	Santos Ltd (P)
Della S.A.	Moomba S.A.	43	Santos Ltd (P)
Moomba S.A.	Adelaide S.A.	781	Pipelines Authority of South Australia (G)
Moomba S.A.	Wilton (Sydney City Gate) NSW	1300	The Pipeline Authority (G)
Young NSW[e]	Wagga Wagga NSW	130	The Pipeline Authority (G)
Young NSW[e]	Lithgow NSW	270	The Pipeline Authority (G)
Dalton NSW[e]	Canberra ACT	58	The Pipeline Authority (G)
Wilton NSW	Plumpton NSW	51	The Australian Gas Light Company (P)
Plumpton NSW	Hexham/NSW	163	The Australian Gas Light Company (P)
KeonPark/Wodonga	Shepparton VIC	331	Gas & Fuel Corp. VIC (G)
Marlin(Shore) VIC	Longford VIC	55	Esso/BHP (P)
Longford VIC	Dandenong VIC	174	Gas & Fuel Corp. VIC (G)
Dandenong VIC	West Melbourne VIC	44	Gas & Fuel Corp. VIC (G)
Dandenong VIC	West Melbourne VIC	82	Gas & Fuel Corp. VIC (G)
Dandenong VIC	Morwell VIC	127	Gas & Fuel Corp. VIC (G)
Brooklyn VIC	Ballarat/Bendigo VIC	197	Gas & Fuel Corp. VIC (G)
Brooklyn VIC	Corio VIC	53	Gas & Fuel Corp. VIC (G)
Longford VIC	Tyers VIC	65	Gas & Fuel Corp. VIC (G)
Mt. Franklin VIC	Bendigo VIC	53	Gas & Fuel Corp. VIC (G)
Pakenham VIC	Wollert VIC	91	Gas & Fuel Corp. VIC (G)
Wandong VIC	Kyneton VIC	59	Gas & Fuel Corp. VIC (G)

[a] Excludes pipelines of less than 100 mm diameter and pipelines less than 40 km in length. [b] P denotes privately owned and operated,. G denotes public owned and operated.
[c] Operated by the Pipelines authority of SA (G). [d] N.T. Gas Pty Ltd is a private company and a subsidiary of AGL, a small amount of equity is held by the NT Government.
[e] Lateral off the Moomba to Wilton pipeline.

Source: BMR, Petroleum Exploration and Development Tiles Key. September 1987
The Pipeline Authority 1986-87 Annual Report
Energy 2000, Policy Review Discussion Paper No. 5. March 1986

APPENDIX 3: CURRENT LEGISLATIVE AND REGULATORY FRAMEWORK

Government ownership and/or control pervades all sectors of the gas and electricity supply industries in Australia. This appendix outlines the major areas of legislation and regulation. A clear understanding of the current arrangements and their variation across state/territories and industries is essential if efficiency in areas such as resource use, pricing and energy supply is to be addressed adequately. This appendix thus forms the basis for the examination of other issues discussed in this report, particularly corporatisation of public utilities.

The electricity and natural gas industries in Australia have evolved on a state-by-state basis with little trade across state borders. There is extensive government ownership and a high level of regulatory control, although this varies considerably between the industries and across states/territories. For example, the NGI has elements of public and private ownership and operates under differing regulatory arrangements. In contrast, the ESI in Australia is dominated by government owned authorities, which, in many cases, are also responsible for administering parts of their regulatory environment. In each industry, governments closely regulate entry.

This appendix outlines the legislative and regulatory framework applying to electricity and, subsequently, gas. Each part is structured around five main headings: legislative charters; social regulation; restrictions on competition; operating controls; and performance measures. Discussion under the first heading outlines the broad legislative functions/objectives attaching to each utility. The second considers social regulation such as CSOs, safety and licensing requirements, and regulation aimed at protecting the environment. Legislation restricting competition, as well as other less obvious arrangements that impede entry, are examined under the third heading. The next section discusses the various forms of operating controls imposed on utilities, either by legislation or via ministerial oversight. The final section deals with various financial and non-financial performance measures used in assessing the performance of utilities.

3.1 The electricity supply industry

There is extensive state/territory government regulation and ownership of the ESI in Australia. Direct involvement by the Commonwealth Government in the operation of the Snowy Mountains Hydro-Electric Scheme reflects its joint interest with the New South Wales and

Victorian Governments. The scheme plays an important role in supplying electricity to these States and the ACT.

In each state/territory, responsibility for electricity generation and transmission is given to a single statutory authority under its principal Act (see Attachment 3.1). In the Northern Territory and all states except New South Wales, Victoria and Queensland, the same authority also has prime sole responsibility for the distribution of electricity. The distribution network in New South Wales operates under separate legislation from that applying to the authority responsible for generation and transmission, while although operating under the same legislation, distribution in Queensland is nominally separate from the remainder of the industry. In Victoria, distribution is shared between the SECV, which also handles generation and transmission, and eleven municipal electricity undertakings (MEUs), which account for approximately 20 per cent of the State's distribution activities. In the ACT, electricity generated by the SMHEA and ECNSW is wheeled across the New South Wales grid and then distributed by the local authority.

3.1.1 Legislative charters

The charter and policy objectives of electricity authorities are similar. In the main, the authorities are required to provide safe and reliable electricity to their customers at reasonable cost. The charter of ECNSW is typical. According to its 1990 Annual Report (p. 6), it is required to:

> ... provide a safe and reliable supply of electrical power at reasonable cost to the people of New South Wales and to industrial and commercial undertakings throughout the State.
>
> To promote and encourage the responsible development and use of the resources of the State in connection with the generation of electricity.
>
> To undertake coal mining operations and to otherwise secure reliable and economical supplies of coal with the objective of reducing the cost of electricity.
>
> To explore the prospects of using alternative technologies in the generation of electricity.

The charter of each authority requires that it discharge commercial as well as non-commercial functions, and in most cases extends to regulatory functions as well. The enabling legislation generally requires that authorities comply with government policies, makes provision for the relevant minister to issue directives and provides for government involvement in decision-making processes covering the borrowing, contracting, investment and pricing activities of authorities. In the case of pricing, provisions commonly exist governing the authorities' broad approach to charging - such as what supply costs should be considered in setting tariffs and the manner in which these should be reflected in the tariffs applied to different users. Further information relating to the nature of these requirements is provided below.

3.1.2 Social regulation

The following discussion examines legislation and government policy relating to CSOs, safety and licensing requirements, and the environment.

Community service obligations

CSOs encompass a range of non-commercial services provided by electricity authorities under legislation or government direction. Information relating to the nature, funding arrangements and, where available, the annual cost of CSOs currently applying to these authorities is set out in Table 3.1. The economic rationale and the methods of funding CSOs are discussed in Appendix 5.

The major CSOs applying to electricity authorities include:

- uniform tariffs within customer classes;
- subsidised tariffs to certain customer classes;
- pensioner and other rebates;
- obligation to supply; and
- regional development and employment programs.

As evident from Table 3.1, however, many authorities are also required to undertake additional CSOs.

- **Uniform tariffs within customer classes**

The requirement to apply state-wide uniform tariffs to particular classes of customer (eg households) is considered a CSO because the resulting price of electricity does not reflect the cost of providing the service. Uniform prices give rise to cross-subsidies between users within the same class because some (eg urban households) pay prices above the cost of supplying them in order to finance prices which are lower than supply costs to others (eg rural households).

For some authorities, uniform tariffs are applied as a result of ministerial directive. This is the case in Victoria, South Australia and the Northern Territory. In other cases, it may be stipulated in the authorities' legislation. In Tasmania, for example, the Principal Act (s. 54) specifies that the HECT must:

> ... provide for the same general rates of charges for electricity sold or supplied by the Commission to consumers outside the city of Hobart as are charged in like cases to consumers within that city.

Similarly, in determining tariffs the QEC is required under its Principal Act (s. 64) to:

> ... have regard to and proceed towards the objective of progressively equalizing throughout the State the prices to be paid by consumers to whom a particular tariff applies.

Table 3.1 **Electricity authorities' community service obligations**

Organisation	*Nature of CSO*	*Funding arrangement*	*Estimated annual cost ($' million)*
SMHEA	Provision of irrigation water	Funded by SMHEA	6.0
	Provision of services to local towns	Funded by SMHEA	1.03
	Maintenance of tourist facilities	Funded by SMHEA	0.13
	Search and rescue facilities	Fee for service arrangement	0.01
NSW Electricity Supply Industry	Uniform tariffs	Funded by ECNSW	50-70
	Pensioner rebates	Metropolitan councils bear full cost; rural councils are subsidised by other councils and from Consolidated Revenue	20.9
	Assistance to industry	Funded by ECNSW and the electricity councils	11.4[a]
	Account payment assistance	Funded by electricity councils	6.0[a]
	Subsidies to remote councils	Funded by ECNSW	5.9
	Roads and traffic subsidy	Funded by electricity councils	4.2[a]
	Remote area connection subsidy	Funded by electricity councils	4.0[a]
	Life support system rebates	Funded by individual electricity councils	0.2[a]
SECV	Uniform tariffs	Funded by SECV	na
	Social justice campaign	Funded by the Government; SECV bears costs of administration	9.4
	Public lighting	SECV bears one third of the capital costs	4.0
	Underground and relocation of distribution lines	Funded by SECV	1.5
	Flexible account payment options	Funded by SECV	1.0
	Energy relief grant scheme	Funded by the Government; SECV bears costs of administration	0.8
	Home energy advisory service	25 per cent funded by SECV	3.0
	Salinity mitigation program	Funded by SECV	0.27
	Life support schemes	Funded by the Government; SECV bears costs of administration	0.16
QEC	Uniforms tariffs	The QEC co-ordinate transfers between the electricity boards to support equalisation of prices. Each board internally funds price discrepancies within franchise areas	na
	Pensioner rebates	Funded by QEC	15.1
	Rural electricity subsidy scheme	Funded by electricity boards	0.9
ETSA	Uniform tariffs	Funded by ETSA	na.
	Rebates for pensioners and welfare recipients	Funded by SA Department of Community Welfare; ETSA bears administrative costs	7.7
	Concessions to industry	Funded by ETSA	7.0
	Subsidy to users taking privately generated electricity	Funded by Government; ETSA meets administration costs	3.0

Table 3.1 (cont.) **Electricity authorities' community service obligations**

Organisation	*Nature of CSO*	*Funding arrangement*	*Estimated annual cost ($' million)*
ETSA (cont)	Undergrounding of cables	ETSA provides funds on a two-for-one basis with local councils	2.6[a] for ETSA
	Supply to Aboriginal communities	Formerly met by State and commonwealth Governments, but now funded by ETSA	1.7
	Emergency payments	Funded by ETSA	0.08
SECWA	Uniform tariffs	Funded by ETSA	38.0
	Pensioners concessions (rebates, and no connection or metering fees)	Funded by ETSA	8.2
	Supply to Aboriginal communities	Funded by Commonwealth Government; SECWA meets administrative costs	na
	Concession for low-income households with dependent child	State Government funded	na
HECT	Uniform tariffs	Funded by HECT	na
	Subsidised supply to Bass Islands	Funded by HECT since 1984	3.4
	Pensioner rebates	Rebates funded by HECT. Government also foregoes the 5 per cent surcharge on pensioner accounts	2.9 for HECT 1.0 for Government
	Advisory services	Funded by HECT	1.8
	Maintaining tourist facilities	Funded by HECT	0.5
	Provision of infrastructure in remote locations	HECT contribute to cost	0.4
	Undergrounding of cables	Funded by HECT and State and Local Governments	0.2 for HECT
	Subsidised extensions to new rural customers	Funded by HECT	0.2
PAWA	Uniform tariffs	Funded by PAWA	na
	Remote area supply	Funded by Commonwealth Government	17.5
	Concessional rates for pensioners and low-income earners	Funded by NT Department of Health and Community Services	1.3
ACTEW	Uniform tariffs	Funded by ACTEW	na
	Pensioner rebates	Funded by Housing and Community Services Bureau; ACTEW bears costs of administration	0.92

[a] This is a budget figure

na = Not available

Note: Unless otherwise specified, all estimated costs exclude administration costs.

Source: Information provided in submissions and/or by electricity authorities in response to a Commission questionnaire.

In Western Australia, the legislation is not as specific. The Act does not formally require SECWA to establish uniform tariffs, but it does specify that it must have regard to the special needs of persons who reside or carry on business outside cities or townships. SECWA has interpreted this as requiring that tariffs for each customer class should be uniform throughout the State.

In all states/territories, uniform tariff arrangements are funded by the authorities themselves. Legislation preventing competition (see Section 3.1.3) enables the authorities to engage in cross-subsidisation between users whereby revenue shortfalls by some groups of customers are offset through 'overpayments' by others. The funding arrangements in New South Wales and Queensland, although still undertaken internally, are somewhat different to other states, as responsibility for distribution is separated from the bulk supply of electricity. In New South Wales, some electricity councils meet a portion of the costs of uniform pricing through the supply tariff charged by ECNSW, since variations in the tariff paid by councils do not fully reflect differences in the cost of bulk supply to some councils (ie those councils closest to power stations cross-subsidise more remote councils). The price of electricity supplied by individual councils is also required to be uniform within classes; hence there is some cross-subsidisation between the customers of a particular council.

In Queensland, the costs of uniform pricing are directly borne by the regional distribution boards. The wholesale price of electricity delivered by QEC consists of a bulk supply tariff and an amount transferred in support of the uniform tariffs applied by the boards. These transfers are calculated and coordinated by QEC such that all boards are left with balanced budgets. The magnitude and direction of the cross-subsidies needed to support uniform pricing in Queensland is not known, but, in 1988-89, transfers between the boards in support of uniform pricing were estimated at $14 million.

Some authorities have attempted to estimate the extent and cost of cross-subsidies to particular customer classes. For example, SECWA estimates that uniform pricing for its electricity customers in 1988-89 cost approximately $38 million (50 per cent for residential customers and 50 per cent for commercial/industrial tariff customers). The New South Wales Government (sub. 40, p. 66) has estimated that discrepancies in costs across the State's supply grid amount to between $50 and $70 million per year. While this represents less than 0.2 cents per kWh on the average sale price of some 6 cents per kWh, the total subsidy to some distribution authorities is substantially greater.

- **Subsidised tariffs to certain customer classes**

In addition to cross-subsidies to support uniform tariffs, electricity authorities are also expected to subsidise consumers in certain tariff classes. For instance, a New South Wales Working Party recently established that consumers on commercial and light industrial tariffs generally subsidise consumers in the industrial and domestic tariff classes.

Subsidised tariffs are funded internally through cross-subsidies. One of the few studies covering these subsidies (SECV 1989), found that, in 1987-88, Victorian electricity users in the farm/rural sector, received subsidies worth in excess of $57 million. This subsidy is greater than the amount of revenue derived by the SECV from this customer class. A preliminary assessment by the HECT has found that subsidisation of rural electricity customers by urban users is between $26 - $31 million.

- **Pensioner and other rebates**

All authorities are required to supply electricity to certain 'disadvantaged' consumer groups on concessional terms. This usually involves a rebate or discount for pensioners, other low-income groups and people with special requirements, such as those requiring life support systems.

Assistance for pensioners is part of government policy in all states and territories. In Victoria, for example, the SECV pays pensioners and disadvantaged groups rebates under the State Government's Social Justice Program. In addition, Government policy prevents it from charging a fee for late payment, and it is also expected to reduce the number of disconnection's for non-payment.

There are numerous other social equity programs undertaken by authorities. In New South Wales, for example, the Electricity Councils provide welfare agencies (eg the Salvation Army) with $30 electricity vouchers for distribution amongst the poor. In South Australia, ETSA is involved in a similar program, whereby it assists in the payment of electricity bills for people in acute, short-term financial difficulty.

Funding for pensioner rebates and discounts is usually undertaken internally by the authority. The situation in New South Wales, however, is slightly more complex as funding is organised by the electricity councils rather than a single authority. All metropolitan councils meet the cost of pensioner rebates, while regional councils are partially reimbursed for their concessions through the Electricity Development Fund (EDF). The EDF is funded by Sydney Electricity ($25 million for 1990-91) and Prospect County Council ($13 million for 1990-91). Funds drawn from the EDF cover approximately 45 per cent of the cost of pensioner rebates administered by the regional councils.

As detailed in Table 3.1, not all authorities are expected to fund pensioner rebates and other welfare-related concessions. In the case of SECV and ETSA, the government directly funds these rebates and concessions, although each authority bears the cost of administration.

- **Obligation to supply**

Another CSO provided by electricity authorities arises from their obligation to supply customers on request and/or to recover less than the full cost of making new connections to the grid. The current situation in each state/territory is as follows:

- New South Wales - the extent of cost recovery on new connections varies between councils. In urban regions, the arrangements vary from a zero to 100 per cent subsidy, while in remote rural areas it is common for customers to bear the majority of the capital costs of grid connection. Some of these customers, however, are eligible for a grant covering 75 per cent of the capital cost. This scheme is administered by the councils and funded by the EDF.

- Victoria - full cost recovery applies to all new connections.

- Queensland - customers contribute to the cost of new connections. However, there is a scheme funded by the electricity boards which subsidises some rural connections.

- South Australia - a State Government funded subsidy applies; ETSA meets the costs of administration.

- Western Australia - customers, except pensioners and other welfare recipients, contribute to the capital cost of new connections. Some subsidies exist for new rural connections (s. 54, p. 14).

- Tasmania - if new installations are beyond 2 spans (urban) or 3 spans (rural) from existing lines, a connection fee is levied. However, if other customers subsequently require connection in the same area, then a portion of this charge is reimbursed. The most expensive supply undertaking for HECT, is its obligation to provide the Bass Strait Islands with electricity.

- Northern Territory - remote connections (including Aboriginal settlements) are subsidised by the Commonwealth Government.

- ACT - full cost recovery applies for new connections.

Authorities in Western Australia, South Australia and the Northern Territory supply electricity to numerous remote Aboriginal townships. In the case of SECWA, funds for these programs are provided by the Commonwealth and State Government, while electricity supply to communities in the Northern Territory is subsidised by the Commonwealth Government. In South Australia, however, the authority is responsible for meeting the cost of grid extensions and remote supply operations in Aboriginal townships.

- **Regional development and employment programs**

In general, authorities are expected to assist governments with their regional development and employment policies. In New South Wales, for instance, the Principal Act (s. 13) empowers ECNSW to:

> ... promote and encourage the development and use of natural resources of the State in connection with the generation of electricity; and
>
> To promote and encourage the use of electricity and especially the use thereof for industrial and manufacturing purposes and for the purposes of primary production.

SECWA stated in its (sub 54, p. 41) submission that it has 'been encouraged by the State Government to develop the energy supply industry in WA to facilitate economic growth'.

Compliance with government policy in the area of state development has resulted in some authorities, particularly those in New South Wales, Queensland, and Western Australia, supporting local coal mining operations. This has meant continued use of uneconomical mines as a means of sustaining local industry and employment (sub. 40, p. 65; sub. 27, p. 20). The pre-payment by SECWA, in 1988, of $15 million for coal from the state owned Collie mine, is another example of such support. This payment was made following a Ministerial directive recorded in SECWA's 1989 Annual Report. SECWA subsequently sought and received compensation for these monies plus interest.

Other regional development programs undertaken by electricity authorities include:

- limiting tariff increases to an amount less than the CPI, or in line with increases in other states/territories;
- the provision of subsidised electricity at uniform prices within customer groups to remote or relatively undeveloped regions (eg Lord Howe Island, Kalgoolie and King Island);
- subsidising the cost of grid connection for selected customers. For example, SECWA operates a Contributory Extension Scheme for farmers and other rural consumers situated in sparsely populated areas of the State's wheat belt. According to SECWA (sub 54, p. 14), the provision of grid connection subsidies for these customers 'was designed to encourage primary industry development in these areas'. The majority of this region is now electrified, but the subsidy still applies; and
- turnover tax exemption of electricity sales to contract users in some states (eg Western Australia and Tasmania).

More generally, state development policy has meant the supply of 'cheap' electricity to large customers. Scope for negotiations between large users and the authorities is generally provided for under legislation. In Tasmania, for example, the Principal Act (s. 54) empowers the HECT to:

> ... enter into a special contract with any person for the sale to him of electrical energy, at such charges and upon such terms and conditions in all respects as the Commission may think fit.

Provision of electricity at contract rates lower than normal tariffs does not necessarily constitute a CSO. Special characteristics such as high levels of consumption, interruptability, direct supply at high voltage and constant demand lead to savings by the authority which may be passed onto the user. If, however, the terms and conditions offered by the authority are the result of government direction with a non-commercial element - explicit or otherwise - then the contract gives rise to a CSO.

Promotion of regional development through provisions in special contracts is usually provided for through legislation. In South Australia, for instance, the *Electricity Supply (Industries) Act 1963-1988* (p. 1) allows ETSA to:

> ... supply electricity on special terms for the promotion and development of industry and for other purposes.

The State Treasurer determines the industries to which this Act applies. As a result, the BHAS Zinc plant at Port Pirie received a concession to the value of $3.75 million on electricity purchases of approximately $10 million in 1989-90. Likewise, the Submarine Corporation was given a subsidy which diminishes over 6 years - starting at 50 per cent with 10 percentage point reductions for each of the following 5 years.

Scope for involvement in special contracts rests with most state governments. For instance, in:

- Western Australia - the Government stated in its submission that SECWA provides electricity:

  > ... to certain categories of industrial customers at concessional rates provided at the discretion of the Government for industry assistance purposes.

- New South Wales - there is a specific fund (the Industrial Development Assistance Fund) which is distributed at the discretion of the Minister. The fund is designed 'to promote industry development'. Further, ECNSW funds and operates a scheme (the Targeted Industrial Development Incentive Scheme) which offers 'electricity at subsidised rates to selective industrial customers'.

- Victoria - the Principal Act (s. 44) requires the SECV to 'facilitate, subject to Government policy, the establishment and development of industrial and commercial operations'.

- Queensland - the Governor-in-Council may direct the regional boards in respect of supply to customers under special agreements.

The funding of these CSOs is accomplished internally, through cross-subsidies. It is difficult to assess the extent of the subsidies as the terms and conditions of special contracts are considered commercially sensitive and are generally unavailable for public perusal. In some cases, however, the funding of such CSOs is more explicit. In New South Wales, some of the larger Electricity Councils and ECNSW contribute to funds which are specifically used for development purposes. For example, the Targeted Industrial Development Incentive Scheme is funded by payments from ECNSW.

- **Other CSOs**

Most authorities are expected to undertake a number of other CSOs, including:

- providing energy advisory services;
- undergrounding of high voltage power lines in urban areas;
- providing concessional electricity tariffs for tourist accommodation and for pumping water used for irrigation;
- maintaining tourist park facilities; and
- contributing to street lighting programs.

It could be argued that some of these undertakings (eg advisory services) are based on commercial principles and therefore do not constitute CSOs. In the Commission's opinion, however, most, if not all, seem to be CSOs.

Some authorities are expected to provide the public with information about electricity use and how to use energy more efficiently. For instance, SECV make contributions to the Home Energy Advisory Service as part of discharging its obligations under its Principal Act (s. 12), which requires that it must:

> ... advise and assist customers in energy conservation, and in particular in the efficient and effective use of electricity.

The provision of similar services by other authorities is discussed further in Chapter 10 and Appendix 11.

Although advisory services may be provided as part of a commercial firms operations, it is not clear to the Commission that, if placed in competitive environment, authorities would undertake these services to the extent they currently do.

In light of the bushfire and possible health risks associated with over-head power lines, some authorities have placed existing over-head lines underground in certain residential areas. Such actions are considered a CSO only if they are over and above that which the authority would initiate on commercial grounds. Undergrounding operations are usually funded internally by the authorities, implying a cross-subsidy from general electricity consumers to those who benefit from diminished bushfire and (possible) health risks, and the increased aesthetic value of their surroundings.

According to the SECV, a scheme to recoup the costs of Undergrounding for particular areas would be impractical. Thus, funding for Undergrounding of existing lines is paid for by all SECV customers, regardless of the benefit they derive from such programs.

In South Australia, Undergrounding currently proceeds in those 'areas which provide substantial community benefits' (sub 44, p. 48). ETSA provides funds for Undergrounding on a two-for-one basis with local councils. Hence, where Undergrounding has occurred, the rate-payers in the area contribute, in part, to the cost.

Some authorities are expected to undertake CSOs which are only vaguely related to their operations as electricity utilities. The HECT has introduced several such programs in response to Government initiatives. In 1977, for instance, the tourism and hospitality industries were accorded the concession of having their tariffs reclassified from commercial to residential. The Tasmanian Government has also initiated a special tariff for certain irrigation activities. Under this tariff, irrigators pumping water 'for approved agricultural purposes' receive cheaper electricity during peak periods.

The Tasmanian Government also requires HECT to maintain a range of tourist facilities at its numerous lakes and dams. The cost of these facilities, which include a museum and visitor reception centres (operating at a loss) and boat ramps and barbecue areas (provided free), is funded by the HECT's electricity customers. The SMHEA indicated that it is required to provide similar services.

Some electricity authorities are expected to contribute to the cost of street lighting. In New South Wales, for example, the ESI, through the EDF, contributes to the Traffic Route Lighting Subsidy. Monies from this fund are used to provide lighting for major roads and, in some instances, to relocate hazardous power-line poles. In Victoria, the SECV contributes one-third of the capital cost of major, new public lighting programs.

Safety and licensing requirements

The provision of safe and reliable electricity is usually a requirement under the Principal Act establishing an authority's charter. In addition, authorities are required to establish safety standards for electrical products and licensing provisions for electrical contractors. Most are also expected to administer these standards and provisions.

For example, the Queensland Government stated that QEC is responsible for:

> ... the regulation of electricity use to ensure safety and may register or approve electrical articles, inspect electrical installations and set up and conduct training for electricity industry employees for that purpose.

Under the SECV's Principal Act (s. 50), it:

> ... shall keep a register ... of the several classes of electrical contractors registered pursuant to this part and of renewals suspensions and cancellations of registrations of electrical contractors.

The SECV and the MEUs are also subject to a range of electrical safety requirements under the *Electric Light And Power Act 1958* and regulations created under the Principal Act. The SECV claim that such requirements cost approximately $10 million annually - 80 per cent of which is spent on undertaking inspections of the electrical system, with the remainder used for administration and policing of the requirements.

The HECT performs electrical licensing and product approval on behalf of the Government at an annual cost of $0.2 million.

Safety and licensing requirements vary between authorities. At the national level, greater uniformity is being promoted through the activities of the Regulatory Authority Approvals Committee, the Regulatory Authority Licensing Committee and the Inter-State

Appliance Approval Scheme. The two committees are administered by the ESAA, while the Approval Scheme provides for an authority in one state to recognise the standards of another.

Environmental regulation

Environmental regulation includes requirements to limit pollution, determine construction standards for energy efficient buildings and develop alternative energy sources.

Electricity authorities must comply with state environmental protection requirements in addition to specific responsibilities provided in their legislation. In Queensland, for instance, any development undertaken by QEC is subject to the *State Development And Public Works Act 1981* and the *State Environment Act*. These Acts, which among other things, contain provisions on land use, waste disposal and emissions, are applicable to any large development in Queensland. In Victoria, SECV's Principal Act (s. 12) requires it to have regard to:

> ... environmental factors in the planning, design, construction and operational phases of every project.

Further aspects of environmental regulation are discussed in Appendix 10.

3.1.3 Restrictions on competition

In each state/territory, the ESI has been established as a legislative monopoly with associated restrictions on the private generation and supply of electricity. Exclusive trading rights and other restrictions accorded electricity authorities are listed in Table 3.2.

The legislation affecting the state-owned monopolies, although similar in purpose, varies somewhat between states. In Queensland, for example, the *Electricity Act 1976* (s. 36) gives QEC the power to:

> ... direct, prohibit, restrict or control, or regulate in any other manner whatsoever, the supply and consumption of electricity.

In New South Wales, however, the Principal Act contains no similar conditions - there are no explicit provisions within the legislation providing ECNSW with exclusive rights to generate and transmit electricity. Its monopoly is sustained as part of Government policy, with permission from the Minister required prior to generation or transmission by an organisation other than ECNSW.

Apart from safety requirements, there are usually no formal restrictions on the generation of electricity for private use. In most cases, however, permission from the

Table 3.2: **Restrictions on competition in Australian electricity markets**

State/Territory	*Trading rights*	*Other conditions*
New South Wales	Private generation or transmission requires approval of the Department of Minerals and Energy. The councils hold exclusive franchises for electricity distribution	Electricity councils cannot generate electricity without permission from ECNSW
Victoria	Legislation prevents any private transmission, distribution or supply without the consent of the SECV	ni
Queensland	Under legislation, the QEC may prohibit, restrict, control, or regulate the supply and consumption of electricity. The seven electricity boards hold franchises to supply various parts of the State.	A licence is required to supply electricity. This is subject to ministerial approval. A person may generate electricity for their own requirements.
South Australia	Legislation prevents any generation of electricity for sale, or the sale of electricity in general, without approval from ETSA	Private suppliers must be franchised by local government authorities.
Western Australia	Permission from SECWA is required for the supply of privately generated electricity	No restrictions on private organisations generating or distributing electricity for their own use
Tasmania	Generation and supply of electricity requires authorisation from HECT	Generation for certain private uses is allowed with prior approval
Northern Territory	Private parties require a licence to sell electricity, but not to generated it	Privately generated electricity cannot be sold at tariffs greater than those of PAWA
ACT	ACTEW has the sole right to supply and connect electricity in the ACT	ni

Ni = None identified

Source: Information provided in submissions and/or by electricity authorities in response to a Commission questionnaire.

responsible minister, or the authority itself, must be gained before such electricity can be sold to other parties. In Queensland, for instance, any private generator wishing to provide electricity to another party must be licensed. No formal limitations are placed on the Minister when issuing a licence, although the application must be reviewed by QEC in consultation with the regional electricity boards.

At present, licences for the sale of privately generated electricity apply in areas which do not have access to the state supply grid. In these situations, the authority may deem it more economical to use privately generated electricity rather then extend its own grid or establish stand-alone generating capacity. In remote areas of Queensland, Western Australia and the Northern Territory, for example, local mining companies supply electricity to associated mining townships and adjacent areas.

Where access to the grid is possible, privately generated electricity surplus to requirements can only be sold to the authority. While there are a number of instances of privately generated power being supplied into the public grid, the extent of sales is quite small. Buy-back rates for this electricity are determined by the authority.

Despite various government and legislative provisions restricting entry, some governments have recently sought to allow some private participation within the ESI. For example, Western Australia's next base-load power station will be privately owned and operated, while SECV has expressed an interest in selling Loy Yang B.

3.1.4 Operating controls

Governments have imposed a variety of operating controls on electricity authorities. In part, these controls are intended to substitute for the absence of market-related commercial disciplines created by the restrictions on competition referred to above. They have also been used as an indirect way of fulfilling government policies in areas such as regional development and employment. The controls are enacted through specific legislation, or result from direct intervention by the government or the responsible minister. The main areas in which controls apply, include:

- borrowings;
- budgetary controls and investments;
- exemptions from taxes and charges;
- employment; and
- pricing arrangements.

Each area of control is discussed below.

Borrowings

Legislation and government directives have a significant impact on the borrowing environment of electricity authorities. Government loan guarantees and concessional interest rates give authorities an advantage over private companies in accessing capital. On the other hand, state borrowing limits and other restrictions on borrowings can adversely affect the efficient management of an authority's borrowing and investment program. Provisions relating to borrowing by electricity authorities are summarised in Table 3.3.

Most authorities are required to borrow through the state treasury or a central borrowing authority. Borrowings for capital works fall within the ambit of the state/territory limit determined by the Australian Loan Council (ALC). Borrowing by an authority is therefore indirectly restricted by ALC limits and the subsequent allocations of these limits by the state/territory governments to individual authorities.

Whether directly or through the state's financing arm, borrowings by utilities are government guaranteed. In addition, many governments extend a guarantee to subsidiaries of authorities, such as their coal winning operations. This guarantee gives authorities an advantage in accessing funds compared with private organisations. Some governments have imposed a charge for this guarantee. In New South Wales, for example, the loan guarantee afforded ECNSW and the Electricity Councils attracts a premium based on the credit rating of the authority - ECNSW currently incurs a charge of 0.4 per cent on all outstanding debt. The SMHEA, QEC, ETSA and ACTEW also pay a loan guarantee fee. In Tasmania, the recently introduced State Authorities Financial Management Act 1990 will require HECT to also pay guarantee fees.

Most governments also determine the authorities' terms of borrowing, such as interest rates and maturity or repayment schedule. The basis for interest rates vary. For example, ECNSW and ETSA pay interest at the prevailing market rate, while the HECT is levied according to the 'state rate of interest'. This rate of interest corresponds to the average rate of interest levied on all outstanding Treasury loans. At present, such loans account for approximately 28 per cent of total HECT debt.

Budgetary controls and investments

The use of surplus funds by electricity authorities is subject to approval from the minister or treasury. In most cases, such monies must be invested directly with the treasury or state financing corporation, or returned to consolidated revenue. In the case of SECWA, an arrangement for the control of surplus funds is not needed. According to SECWA, it has had a 'traditional agreement' with the government that it would maintain a balanced operating budget and, consequently, a policy on surplus funds is not necessary.

Table 3.3: **Electricity authorities' borrowing environment**

Authority	*Restrictions*	*Explicit loan guarantee*	*Terms of government loans*
SMHEA	Approval from Treasurer required. Subject to ALC limits	Yes, incurs a charge	Determined by treasurer
ECNSW and Electricity Councils	Borrowing undertaken by NSW Treasury Corporation and on-lent	Yes, incurs a charge	Interest charged at prevailing market rates, plus an administrative fee
SECV	Explicit limit on borrowings. Approval from Treasury required	Yes, but no charge applies	No Government loans exist
QEC	Has contracted with the Queensland Treasury Corporation to manage borrowings	Yes, incurs a charge	As agreed with the Queensland Treasury Corporation
ETSA	Must borrow through the South Australian Financing Authority. With the consent of the Treasurer, may borrow in its own name	Yes, incurs a charge	Loans at market rates
SECWA	Amounts and composition of loans determined by Treasury	Yes, but no charge applies	Determined by Treasurer
HECT	Must raise all loans through the Tasmanian Public Finance Corporation. Loans for new power developments must be authorised by Parliament	Yes, incurs a charge	State rate of interest applies to Treasury loans
PAWA	Can only borrow from NT Treasury	Yes, but no charge applies	Determined by Treasurer
ACTEW	Approval required from Treasurer. Subject to ALC limits	Yes, incurs a charge	Determined by Minister for Finance

Source: Information provided in submissions and/or by electricity authorities in response to a Commission questionnaire

Legislative provisions also affect the investments which most authorities undertake For instance, it is usually a requirement that major investments and contracts undertaken by electricity authorities be approved by the responsible minister. In New South Wales and Victoria, any contract in excess of one million dollars is not binding unless it has received ministerial approval. The corresponding figure for SECWA and ETSA is two million dollars, while investments undertaken by the electricity boards in Queensland need to be ratified by the Minister if they exceed $250 000.

Control over investments enables a minister to veto a project even though it may be economically viable. Conversely, the minister may insist that uneconomic projects proceed.

Exemptions from taxes and charges

The treatment of authorities in respect of a number of taxes and charges is summarised in Table 3.4. In the main, most authorities are exempt from liability to Commonwealth income and sales taxes, and some state taxes and charges. A requirement for authorities to pay an amount in lieu of these taxes and charges applies in some cases, but is usually limited to coverage of relatively minor state and local government charges.

As part of a move towards commercialisation/corporatisation, many governments are proposing electricity authorities pay Commonwealth income tax equivalents to state treasuries. However, no authority has yet made an explicit payment in lieu of income tax. Under the Tasmanian SAFM Act, the HECT is now liable for income tax equivalents as determined by the State Treasurer. According to the Act (s. 35):

> The estimated taxation-equivalent is an amount which the Treasurer determines to be equal to the amount of income tax, other than capital gains tax, the [HECT] would have to pay under the laws of the Commonwealth if it were a company.

The required payments are retrospective to 1 July 1990, although the Act has provision allowing the Treasurer to waiver or defer such payments.

Some authorities (eg ECNSW and HECT) have received an exemption from paying federal import duties on certain items under tariff concession arrangements. For example, the Commonwealth Government exempted the HECT from paying duties on equipment imported for use in its hydro-electric power stations (Tasmanian Government, sub. 50, p. 30). It must be noted, however, that such exemptions may also be granted to commercial firms and do not apply generally to goods imported by authorities.

Employment

Commissioners of electricity authorities are generally appointed by the Governor or Governor-in-Council. In most instances, the Governor also determines remuneration and the terms of appointment under which the commissioners serve.

Table 3.4: **Government taxes and charges payable by electricity authorities**

	Commonwealth taxes and charges				*State and territory taxes and charges*		
Authority	*Income tax*	*Fringe benefits*	*Sales tax*	*Excise*	*Payroll*	*Other*[a]	*Local government rates & charges*
SMHEA	no	yes	no	yes	yes	no	yes[b]
ECNSW	no	yes	no	yes	yes	no	yes[b]
NSW	no	yes	no	yes	yes	yes	yes
SECV	no	yes	no	yes	yes	yes[c]	Yes[c]
QEC	no	yes	no	yes	yes	no	yes
ETSA	no	yes	no	yes	yes	no	yes[b]
SECWA	no	yes	no	yes	yes	no	yes[d]
HECT	No[e]	yes	no	yes	yes	no	yes
PAWA	no	yes	no	yes	yes	no	yes
ACTEW	no	yes	no	yes	yes	no	yes

[a] Includes land tax, state excise and state stamp duty on mortgages, cheques, conveyances etc., but not bank charges.
[b] Ex gratia payment in lieu of charges.
[c] SECV pays land taxes and local rates on commercial facilities.
[d] SECWA only pays local rates on employee houses, but water rates on all property.
[e] The Tasmanian Treasurer may require HECT to pay income tax equivalent.

Source: Information provided in submissions and/or by electricity authorities in response to a Commission questionnaire.

In Queensland, the Minister may become involved in staffing matters. According to the Principal Act (s. 20), the list of QEC employees nominated for the upcoming year may be amended or modified by the Minister.

Salaries and conditions for employees in some electricity authorities are not bound by state public service legislation. For instance, QEC's Principal Act (s. 20) states that:

> the provisions of the Public Service Act 1922-1973 are not applicable to employees of the Commission.

Government ownership of electricity authorities, however, has prevented management from offering remuneration deals which differ considerably from those within the public sector generally. Therefore, despite exemptions applying, pay scales for most electricity authorities embody their respective state public service conditions and pay.

Pricing arrangements

Pricing arrangements for electricity vary according to the type of customer. For most customers, the price of electricity is set according to published tariffs and is required to be uniform within the same customer class. However, tariffs for users with large loads or scope to interrupt their load are negotiated outside normal tariff arrangements. Provisions in the legislation allowing authorities to enter into special contracts with such users were discussed in Section 3.1.2.

Published tariffs are usually set and structured by the authority, but - explicitly or otherwise - subject to approval by the responsible minister or the government (refer to Table 3.5). Final agreement on tariff increases and restructuring is usually achieved following a consultative process between the government and the authority. The degree of public scrutiny of the process varies between states/territories.

In South Australia, for instance, tariffs are set following an internal review process involving the Government and ETSA. The deliberations between the Government and ETSA are not open to public scrutiny. In Victoria, SECV makes a formal submission (available for public perusal) to the Government which then decides on the appropriate increase in the general tariff level. In 1990, for the first time since this system was established, the Government rejected SECV's recommendation for a 5 per cent increase and set the increase at 5.9 per cent.

The tariff-setting arrangement in New South Wales is open to some public scrutiny and participation. Tariff changes and restructuring are approved by the Minister for Minerals and Energy following recommendations from an independent inquiry. This inquiry receives submissions from ECNSW, which are confidential, as well as other interested parties. The final decision on tariff adjustments rests with the Government.

Table 3.5: **Government involvement in tariff arrangements for electricity authorities**

Authority	*Procedures established by government*	*Government guidelines*
SMHEA	Procedures established by Commonwealth, NSW And Victorian Parliaments	Electricity charges equal the net cost of production, as defined in the Act/Agreement
ECNSW	Minister determines prices following recommendations from a public inquiry.	Terms of reference for the inquiry set by the Minister. Inquiry must have regard to the Government interest, which includes reducing cross-subsidies between classes and a need for gradual adjustment in implementing reform
NSW Electricity Councils	Set by councils, although the Minister has the power to adjust tariffs following recommendations of a public inquiry	Increases to be no greater than half the CPI increase
SECV	Authority submits recommended changes to the Government for approval	Price increases are to be maintained below CPI and cross-subsidies between classes reduced
QEC	Determined by QEC after referral to the Government	The Act provides that in setting prices, the QEC shall ensure that prices are 'fair and reasonable' and uniform throughout the State
ETSA	Annual tariff adjustment set by ETSA board in consultation with the Government	Current guidelines require that increases be less than CPI and, as far as possible, reduce cross-subsidies between customer classes
SECWA	Tariffs set by SECWA, subject to Government approval. Major adjustments to tariffs require approval from Cabinet.	There is a Government commitment to keep domestic tariff increases below CPI
HECT	Retail tariffs subject to approval by State Cabinet	Required to recover, on a user-pays basis, the real economic cost of facilities and services
PAWA	Prices are determined by the Minister	ni
ACTEW	Changes determined by ACTEW. Minister has power of disallowance within 30 days of gazettal	ni

ni = None identified.
Source: Information provided in submissions and/or by electricity authorities in response to a Commission questionnaire

Tariff changes recommended by authorities - whether to a public inquiry or directly to the government - are often constrained by legislation and/or government guidelines. The most prevalent tariff setting restriction is a requirement (sometimes a target) that tariff increases be less than the CPI. Another requirement is that authorities ensure that prices are set so as to recover supply costs. As stated in the Queensland Government submission (sub. 27, p. 14), the Principal Act:

> ... requires QEC to ensure the adequacy of prices so that the Commission and the Electricity Boards secure sufficient funds to meet their operating costs, to make provisions for capital works and to contribute to reserves (such as capital works reserves) authorised under the Act.

In the case of the SMHEA, prices are required to recover the operating costs and historical capital costs of the Scheme.

Apart from meeting normal operating costs, electricity authorities are also expected to fund the majority of their CSOs. The 'cost' of the CSOs is subsumed into the tariff structure. A mixture of internal funding through the tariff system and explicit cost recovery arrangements may augment the distortionary effects of CSOs. The 1990 Inquiry into Electricity Tariff and Related Matters in New South Wales raised this issue with respect to capital contributions paid by new customers. It found that, although the cost of connections is subsumed into the tariff, some customers were also required to make explicit capital contributions towards new connections. It suggested (p. 9.1) that such payments:

> ... should be determined in accordance with the basic premise that the user pays but it is not reasonable for a customer to be charged twice, once by direct payment and again through the tariff.

The level of tariffs charged by authorities may be increased by various government taxes or charges. In Tasmania, for instance, the Government has imposed a 5 per cent surcharge on retail electricity sales, except pensioner accounts, while a separate levy applies to non-tariff customers.

3.1.5 Performance measures

Governments currently use a variety of mechanisms to assess, or aid assessment, of electricity authorities. These mechanisms represent administratively based alternatives to disciplines which would apply to private suppliers. They include:

- ongoing scrutiny by central agencies;
- periodic reviews and audits;
- annual reporting requirements;
- corporate plans and associated targets; and
- government-based financial and non-financial targets.

The subsequent discussion concentrates on the financial and non-financial targets set by governments. These targets, and contributions made by the authorities, are detailed in Table 3.6.

Financial targets

As part of their corporate plans, most electricity authorities have a number of on-going financial targets. Most are also required to make contributions to government, usually as a 'dividend' or as a tax on turnover. Only some authorities, however, are expected to attain pre-determined financial targets specified in legislation or agreed upon in consultation with their respective government. The only instances where such targets exist are in Victoria, Western Australia, Tasmania and the Northern Territory. Such targets also apply to the Electricity Councils in New South Wales. The arrangements for each of these cases are considered below.

- Victoria - the SECV has a financial performance target empowered under legislation. The *Public Authorities (Dividend) Act 1983* requires the SECV to achieve a minimum real rate of return on its capital, with the objective of providing management with an incentive to reduce waste and improve operating efficiency. The target, which is presently set at 4 per cent of the written down replacement cost of employed assets, has been achieved by SECV each year since its inception.

- Western Australia - the Government has recently formulated a range of financial targets to apply to SECWA over the next 3 years. The major targets established as part of a performance agreement include a return on revenue and assets, a debt-equity ratio, an internal funding ratio and a target for the average real cost of total energy sold. SECWA is required to detail its performance against these targets in its annual report.

- Tasmania - to obtain the status of a commercial operator, HECT must achieve a real rate of return on assets of not less than 4 per cent.

- Northern Territory - the ESI has required subsidies from the Federal Government since its establishment. PAWA currently meets around 73 per cent of its costs, with the remainder being met by the Commonwealth and Territory Governments. A key financial target agreed upon by PAWA and the Federal and Northern Territory Governments is full cost recovery for the majority of PAWA's electricity operations by 1994-95. Operations subject to this target account for around 98 per cent of electricity sales.

- New South Wales - the Electricity Councils have entered into performance agreements with the Minister for Minerals and Energy aimed at commercialising their activities and making them more accountable to their customers. Included in the agreements are targets for operating costs, returns on assets and a debt-gearing ratio. The results of these performance agreements are to be published.

Table 3.6: **Electricity authorities' financial targets and government contributions payable, 1989-90**

Authority	*Financial target*	*Amount ($ 'million)*	*Contributions*	*Amount ($ 'million)*	*Other*
SHMEA	ni	-	ni	-	ni
ECNSW	ni	-	Dividend payment	160	ni
NSW Electricity Councils	Established as part of performance agreements		Contribution to Electricity Development Fund	38[a]	Non-financial targets under the performance agreements
SECV	Minimum real rate of return on written down replacement cost of assets (currently at 4 per cent)	784[b]	Dividend of up to 5 per cent of public equity[c]	120[d]	ni
QEC	ni	-	ni	-	ni
ETSA	Break-even operating result	-	Dividend payment 5 per cent levy on revenue from electricity sales A charge by SAFA on a non-repayable capital contribution	47 38.8 16.6	ni
SECWA	Return on revenue (4.5%)[e] Return on assets (2.2%) Face cash flow ratio (24%) Costs to assets ratio (45%)		3 per cent levy applies to metered sales of electricity	27	Non-financial targets under the performance agreement
HECT	ni	-	Dividend payment 5 per cent surcharge on all retail sales of electricity except pensioner accounts Major industrial customers levy to State Treasury	Na 10.7 4.8	ni
PAWA	Full cost recovery by 1994-95	f	ni	-	ni
ACTEW	ni	-	Dividend as determined by the Minister	8	ni

[a] This amount is for 1990-91
[b] This represents a real return on the average assets-in-service of 5.4 per cent.
[c] Public equity defined as current value of operating assets less associated debt.
[d] Of the $120 million, $110.4 million went to the Government and $9.6 million to the Victorian Equity Trust. This represents a return on public equity of 1.7 per cent
[e] All bracketed figures are targets for 1992-93
[f] Deficit for 1898-90 - excluding subsidies - was $55 million
ni = Non identified
Source: Information provided in submission and/or by electricity authorities in response to a Commission questionnaire

No similar financial targets were identified by the Commission for the remaining authorities. A number do, however, make dividend payments or contributions to their governments, although the basis for determining these payments varies. In Victoria, the Public Authorities (Dividend) Act 1983 requires certain state instrumentalities, including the SECV, to return a dividend on their public equity. This payment is intended to represent a dividend to shareholders in return for their capital contribution. The dividend can be up to 5 per cent of the current value of operating assets less associated debt. The amount paid by the SECV for 1989-90 was $120 million - a return on the SECV's public equity of 1.7 per cent.

Similar legislation now exists in Tasmania. Under the *State Authorities Management Act 1990*, the Treasurer requires HECT to pay a dividend after consultation with the relevant Minister and after consideration of the authority's financial position and 'the social and economic effects on the community of the payment'.

As evident from Table 3.6, most other authorities pay dividends, although they are not required to under legislation and in some cases such payments are tantamount to taxes. Without a formal framework of assessment established by government, contributions or dividends can be based on an 'ad hoc' evaluation of an authority's performance. For instance, the Sydney City Council (SCC), now known as Sydney Electricity, was recently directed by the Minister for Minerals and Energy to pay a 'dividend' to its customers. This payment arose from the New South Wales Government (1989) inquiry into the SCC. It found that the Council was in a privileged financial position compared with other New South Wales electricity councils, particularly the rural councils. The SCC was required to pay a uniform $75 rebate to all its customers. This flat rebate did not reflect the relative importance of consumers in terms of quantity consumed or whether they also used gas. Apart from the rebate, the SCC was also directed to purchase all of Sydney's metropolitan transmission lines from ECNSW and to assist ECNSW with it debt repayments. The purchased lines will be vested in all four of Sydney's councils, although only the SCC was required to pay.

In 1989-90, ETSA made a similar 'one-off' dividend payment to the State Government of $47 million. ETSA made an additional contribution to the Government based on the value of their electricity sales. Electricity authorities in Western Australia and Tasmania make similar payments.

These 'ad hoc' arrangements impose no real discipline on the performance of the authorities. Indeed, their nature may well be counter-productive by creating uncertainties for authorities' investment and cash flow planning.

Performance measurement and assessment based on financial information is complicated by differences in reporting procedures across authorities.

As noted by CRA, such differences make 'the comparison of performance between public business entities and comparable private entities difficult, if not impossible'. Moreover, the methods of business reporting vary so much that direct comparisons between electricity authorities are difficult. The main areas of difference are:

- Valuation of assets - SECV prepares accounts on a historical cost and current cost of assets basis. ECNSW and ETSA value operational power stations at current cost, but all remaining assets are valued in historical terms. PAWA and ACTEW value some assets on a current cost basis, with the remainder being at historical cost. All other authorities value assets at historical cost.
- Accounting conventions - all authorities, except QEC, have accounts on an accrual basis. QEC has accounts on a cash basis. In addition to accrual, SECV and PAWA have supplementary accounts on a current cost of accounting basis.
- Depreciation - most authorities depreciate their assets using the straight line method over their expected lifetime. However, there are differences in assumptions made about asset lives. This concern was raised by CRA:

  > ... some States use their own, somewhat unusual, methods of depreciation (eg. Western Australia, which utilises a units of production basis); some States do not use depreciation at all, as in Queensland where a "contribution to capital works" is levied, which leads to a provision some 3 times that of normal depreciation provisions.

- Other areas - CRA also expressed concern over authorities' treatment of foreign exchange dealings and interest incurred during the construction of power stations.

Non-financial targets

The provision of CSOs and restrictions on competition mean that an adequate assessment of an authority's performance under existing arrangements requires the use of non-financial targets. To assess an authority's performance in delivering CSOs, for instance, it is necessary to have access to information covering, amongst other things, the precise objective(s) involved, the targeted group and the cost of delivering the service. Notwithstanding that electricity authorities have major CSO requirements, there are currently no targets aimed at assessing the performance of authorities in delivering these CSOs.

In the absence of direct competition in generation and distribution, there is a case for adopting various non-financial performance targets to promote 'yardstick competition' - administratively created pressures based on comparative performance data across similar activities. The desirability of such targets was commented on by State (except South Australia) and Territory Governments (1990, p. 5) in their submission to the May 1990 Special Premiers' Conference:

> One of the key aspects of effective regulation is the scrutiny of the cost of service provision. To be effective, this requires information on the comparative cost of service provision in other jurisdictions

and in similar operations in the private sector. This form of cost scrutiny is known as 'yardstick competition'.

To the Commission's knowledge, the only authorities currently employing non-financial targets are SECWA and the Electricity Councils of New South Wales. As part of its performance agreement with the Government, SECWA has targets relating to reliability of supply, customer satisfaction, time needed for new connections, plant availability and labour productivity. The Electricity Councils have a similar range of performance targets. The publication of individual performance against these targets is intended to create pressures for the lesser performing councils to match the better performing councils.

Many authorities have initiated non-financial targets as part of their corporate plans. However, these targets are not negotiated with government and as such they do not impose real disciplines on the authorities concerned. Moreover, no provision currently exists to reward or sanction authorities for their actual performance against such targets.

3.2 The natural gas industry

Like electricity, the NGI has developed mainly within state/territory boundaries. In contrast to electricity, however, the industry displays considerable variation in ownership and organisational structures. Public and private utilities operate in transmission and distribution and there are also examples of enterprises with mixed public and private equity in Victoria, South Australia and the Northern Territory. Further, in only some states is the NGI characterised by vertically integrated operations.

This diversity of ownership and organisational structure is reflected in the legislative and regulatory framework of the NGI. The public utilities operating in New South Wales, Victoria, South Australia and Western Australia operate under legislative charters similar to those of their counterparts in the electricity industry. In one case, Western Australia, the one authority (SECWA) supplies both electricity and natural gas. The operations of private utilities are subject to a range of regulatory controls, primarily aimed at constraining market power arising from their status as monopoly suppliers.

The Principal Acts governing the operations of public and private gas utilities are presented at Attachment 3.2. The main features of these Acts and associated legislative and regulatory provisions are dealt with below under similar headings to those used for electricity.

3.2.1 Legislative charters

In most cases, the charter of public gas utilities is based on their Principal Act. In Victoria, for instance, the Principal Act has enabled GFCV to 'secure the ultimate coordination and unification of gas undertakings in Victoria' and take up its duties to:

> ... secure the safe economical and effective supply of gas and fuel in Victoria [and] to encourage and promote the use of gas (s. 23).

According to PASA (1990, p. 4), its charter is to:

> ... construct, operate and maintain high pressure pipelines for transportation of natural gas and liquid hydrocarbons, and where required to purchase and sell natural gas and liquid hydrocarbons, for the benefit of South Australians.

As with electricity authorities, public gas utilities are subject to government involvement in their financial and operating practices. This involvement may be via specific provisions in the legislation or through a cover-all clause in the Principal Act, such as that imposed on PASA (s. 4):

> The Authority is subject to control and direction by the Minister.

In the case of private gas utilities, the scope for direct government involvement in their operation and administration is limited. Nevertheless, the granting of operating licences, which may result in sole trading rights over a particular area, has enabled governments to impose a range of operating controls and monitoring measures. Some utilities are also required to discharge CSOs as a condition of their licence.

3.2.2 Social regulation

A variety of social regulations apply to public gas utilities. The main regulations cover the provision of CSOs, safety and licensing requirements and the environment. Each of these areas is discussed below.

Community service obligations

The major CSOs undertaken by gas utilities are similar to those applying to electricity authorities. They include:

- uniform tariffs within customer classes;
- subsidised tariffs to certain customer classes;
- pensioner and other rebates;
- obligation to supply; and
- regional development and employment programs.

Information relating to their nature, funding arrangements and estimated cost is contained in Table 3.7.

- **Uniform tariffs within customer classes**

Under their Principal Acts, both the GFCV and SECWA must charge a uniform tariff for all users in the same customer class throughout the state. For the GFCV, this

Table 3.7: **Gas utilities' community service obligations**

Utility	*Nature of CSO*	*Funding arrangement*	*Estimated annual cost ($'000)*
TPA	Uniform tariffs under the pipelines System Deed	Funded by TPA	na
AGL (NSW)	Pensioner discounts	Funded by AGL	na
AGL (ACT)	ni	-	-
GFCV	Uniform tariffs	Funded by GFCV	Nil
	Pensioner rebates	Funded by Government and administered by GFCV	9 117 for Government 100 for GFCV
	Supply of tempered LPG at natural gas tariffs	Funded by GFCV	4 000
	Home advisory service	Funded by GFCV	710
	Contribution to the Renewable Energy Authority	Funded by GFCV	450
	Contribution to the Community Service Section of Customer Relations Department	Funded by GFCV	150
	Discount on high efficiency appliances for pensioners	Funded by GFCV	50
	Contribution to Energy Action Group	Funded by GFCV	45
Allgas Energy Ltd	ni	-	-
Gas Corporation of Qld	ni	-	-
Sagasco	Pensioner rebates	Funded by Sagasco	380
	Emergency payments	Funded by Sagasco	30
SECWA	Uniform tariffs	Funded by SECWA	na
NT Gas Pty	ni	-	-

na = Not available
ni = Non identified
Source: Information provided in submission and/or by gas utilities, in response to a Commission questionnaire

includes operations in Albury, New South Wales. For example, Section 72 of GFCV's Principal Act states:

> ... any person to whom the Corporation supplies gas at a domestic tariff is entitled to be supplied with gas on the same terms and conditions as any other person to whom the Corporation supplies gas at that tariff.

The GFCV also charges natural gas tariffs for tempered LPG (TLPG) in areas where natural gas is not available. Provision of TLPG, and the tariffs under which it is supplied, was part of general government policy in requiring uniform tariffs throughout the State. Funds for uniform pricing of natural gas and TLPG undertakings are generated internally, with the annual cost of the TLPG program being estimated at four million dollars.

In the other states/territories where gas is distributed, there are no provisions for uniform tariffs within customer classes. However, not all published tariffs for gas distributed by private utilities necessarily reflects the economic costs of supply. This may be due to the commercial consideration of applying the same tariff to a pre-determined group of customers. That is, most distributors do not find it worthwhile to assess the cost of supplying each individual user and therefore group them according to similar characteristics. On the other hand, tariffs offered by some private utilities appear to contain a price-related CSO.

For example, the price charged by TPA for transmission of gas is based on the average cost of operation, maintenance and construction of the complete network, over the period from 1974 to 2006. This arrangement, under the Pipelines System Deed, ensures a fixed rate for gas delivered for AGL, regardless of the point of supply. Such an arrangement appears to be a non-commercial undertaking and thus constitutes a CSO. The tariff arrangements also include provisions for extensions to the main pipeline. TPA claims that if the cost of spur lines to Orange, Lithgow, Cootamundra and Wagga Wagga had not been rolled into the overall cost of the pipeline system, then they would not have proceeded. This results in a cross-subsidy from those end users on the main line to those who receive gas as a result of the extensions. In addition, the inability of TPA to achieve a return on the capital employed in its operations under the Deed, provides all New South Wales gas customers with rates below those which would, presumably, be charged by a private supplier seeking an economic return. Evidence that TPA's haulage charges are not commercially attractive came with the Commonwealth Government's announcement that, preceding the intended sale of TPA's assets, the haulage fee would have to increase by 25 per cent in January 1991, with another 25 per cent increase in January 1992. The necessary legislation failed to pass through parliament and TPA was subsequently withdrawn from sale.

In South Australia, Sagasco's gas tariffs vary between areas, reflecting the higher costs associated with supply to rural townships. Government endorsement of the report of the 1987 Working Party On Tariffs and Related Matters has led to Sagasco adjusting tariffs, provided they do not create 'disruption or hardship to particular consumer groups'.

Sagasco realises this 'may prove a difficult situation politically'. Despite increased flexibility in tariffs, operations in some regions still do not recover the direct costs of supply - the Whyalla market, for example, has been running at a loss for over two decades.

- **Subsidised tariffs to certain customer classes**

As with the ESI, many gas utilities are required to offer concessions to specified customer classes. Such concessions are not limited to the public utilities. In New South Wales, for example, AGL agrees that its contract users subsidise tariff customers. According to its submission on the draft report, this was partly due to the fact that:

> .past Boards of Inquiry into AGL's gas prices (sic)would not allow price rises to fully reflect increases in costs in servicing (sic)the tariff market. Political factors have contributed to this.

Sagasco currently experiences similar problems with its pricing arrangements, claiming a poor return from the tariff market - particularly the domestic segment of this market. This results in high-return customers subsidising those which would otherwise be unviable. In addition, this arrangement has meant Sagasco:

> ... has been unable to justify on ordinary commercial criteria all the extensions it could have made to the gas reticulation network.

- **Pensioner and other rebates**

Unlike electricity authorities, not all gas utilities are required to offer pensioner rebates or other welfare-related discounts. The exceptions include SECWA's gas activities and the two distribution utilities in Queensland. According to industry participants, this outcome reflects the discretionary nature of gas consumption compared to electricity.

Where rebates do apply, they take the following form:

- New South Wales - as part of AGL's Authorisation, it is required to provide pensioner rebates to the value of $ 2.50 per month. In Newcastle, the allowance is slightly higher. The cost of these rebates is borne by AGL's other gas customers.

- Victoria - as part of the Government's Social Justice Program, GFCV provide a discount on gas bills for pensioners and other welfare recipients. This amounts to a 15 per cent discount on 3 gas bills during the 6 month period from May to November. GFCV is reimbursed for the cost of funding this scheme. However, it is not compensated for the costs of administering the scheme which, according to GFCV, places a significant strain on its finances and operations during this period. Customers eligible for this discount may also receive a discount on high efficiency appliances.

- South Australia - as part of its licensing arrangement, Sagasco offers pensioner rebates of $6.60 per annum. Despite similar rebates offered by ETSA being funded by the Government, Sagasco is required to fund and administer these rebates internally.

- **Obligation to supply**

In circumstances where gas is distributed by a sole supplier, governments have often imposed on the utility an obligation to supply gas on request. The situation in each state is as follows:

- New South Wales - according to its Authorisation, AGL must supply premises within 20 metres of an 'appropriate' gas main. It may only refuse supply if it does not receive an undertaking to purchase the gas for at least 12 months or the person does not provide security to cover the cost of extensions to the main.

- Victoria - GFCV must supply gas to anyone within 20 metres of a gas main. It will connect customers outside this limit, provided the costs are no greater than that allowed for under the uniform tariff arrangement.

- Queensland - gas utilities are required to connect any customer within 20 metres of a gas main. They may gain exemption from the Minister for having to supply people outside this limit provided they can prove the connection to be uneconomical. However, if such an exemption is granted, the Minister may allow an alternative supplier to provide the service.

- South Australia - there are no provisions in the Act which require Sagasco to connect gas on request.

- Western Australia - SECWA has interpreted its Principal Act as requiring that it supply gas to customers on request.

Where an obligation to supply results in subsidised connections, the cost is met by the utility in the form of higher charges on other users.

- **Regional development and employment programs**

Public utilities are generally required to assist state development policies through the provision of concessional gas tariffs to large users. Most Principal Acts empower public gas utilities to establish private contracts with large customers. For example, GFCV's Act (s. 72) says it:

> ... may enter into a contract in writing with any person for the supply of gas to the person on the terms and conditions specified in the contract.

The confidential nature of such contracts makes it difficult to establish if their terms and conditions result in subsidised rates. In an attempt to dispel claims that uneconomical subsidies do occur, GFCV determines contract terms and conditions according to a formula which takes into account such parameters as volume and interruptibility. In addition, GFCV publishes the average price of all contract tariffs to permit a comparison with the average price for non-contract sales.

Despite their confidentiality, there is some evidence available which illustrates the non-commercial nature of some recent gas contracts. For instance, the Western Australian Government (1989, p. 8) stated:

> In this case [the North West Shelf project] the key contract was not the development agreement but the State Energy Commission of Western Australia (SECWA) contract to purchase 10.9 million cubic metres of gas a day for domestic supply... A less ambitious contract reflecting the realities of the situation rather than the political imperatives of the government of the day might have resulted in the project beginning without encumbering the State with a large gas surplus... Indeed, it is fair to say that the original terms of that agreement would have bankrupted the State and it required Federal Government concessions to bail out Western Australia from its impossible financial burden.

This finding suggests that SECWA's original contract with the North West Shelf consortium was shaped by non-commercial considerations. That is, if SECWA had viewed the contract on a purely commercial basis, the negotiated terms and conditions would have been quite different.

Although they have no formal basis for intervention, some governments have involved private gas utilities in their regional development concerns. In New South Wales, for example, AGL is required to contribute up to 0.5 per cent of turnover from gas sales to a Research and Development Fund. Monies from this fund are used to develop the State's energy resources.

Development initiatives can also be promoted by excluding large supply contracts from licensing fee calculations. In Queensland, for instance, the license fee payable by a distribution utility consists of a flat fee($50) and an amount based on turnover from sales of gas. However, gas sales of more than 50 TJ per customer over a 6 month period do not pay the turnover fee. Similar provisions exist for SECWA's large customers.

- **Other CSOs**

Utilities are also required to undertake various other CSOs. Some of the major ones include:

- GFCV contributes to the Home Advisory Service, the Renewable Energy Authority, the Energy Action Group and the Community Service Section of Customer Relations Department. There appears to be no specific legislative provisions that require the GFCV to fund these programs. Instead they have been agreed upon by GFCV at the request of the Government.

- Reflecting Government policy, Sagasco introduced an Emergency Payments Scheme to provide one-off assistance to customers in severe financial crisis.

Safety and licensing requirements

Under the conditions of their licence, gas utilities are required to maintain a safe and reliable gas network. Some public utilities have the added responsibility of administering and assessing the safety of gas pipelines and appliances. Under its Principal Act (s. 27), SECWA is charged with:

> ... promoting the safety, health and welfare of persons engaged in the construction, maintenance, repair or use of energy works and apparatus throughout the State; and
>
> safeguarding operators, users and the public by ensuring that persons engaged in the performance of work on, or operation of, any apparatus or other equipment or plant involving the use of energy.

Environmental regulation

Most pipeline networks are subject to regulation which ensures that gas lines do not significantly detract from the aesthetic value of the surrounding environment. In Western Australia and the Northern Territory, for instance, the granting of a licence to build and operate a pipeline depends on how well the lines blend with the surrounding flora and fauna. When laying new lines, TPA must have regard to similar considerations and is also obliged, as far as practicable, to place lines below the ground. Its Principal Act (s. 35) states:

> In the exercise of its powers under this Act, the Authority shall cause as little detriment and inconvenience and do as little damage as possible.

Legislation and regulation of gas utilities with respect to the environment is discussed further in Appendix 10.

3.2.3 Restrictions on competition

Although private participation is greater within the NGI, governments have still chosen to protect gas utilities from competition - or at least the threat of competition. In addition to state owned monopolies, similar to those found in the ESI (eg GFCV), governments have restricted the supply of gas to licensed, private utilities with pre-defined franchise areas.

Although competition may not be feasible in some areas on natural monopoly grounds, few competitive pressures have been exerted on incumbent suppliers. For instance, most gas utilities are accorded on-going franchises, while new franchise areas are not systematically subject to a process of competitive tendering.

A summary of the restrictions on competition in the gas industry is contained in Table 3.8. Restrictions on competition within transmission and distribution are discussed separately below.

Table 3.8: **Restrictions on competition in Australian gas markets**

State/Territory	*Trading rights*	*Other conditions*
Transmission		
New South Wales & ACT	ni	Licence required under NSW Pipelines Act. Limited provision for carriage of third party gas
Victoria[a]	GFCV has the sole rights for transmission and distribution rights, with exception of limited trading rights for Esso/BHPP	Supply by an organisation other than GFCV requires approval from the Governor-in-Council
Queensland	ni	Pipelines must be licensed. All pipelines, apart from the Government pipeline, are required to be common carriers
South Australia	PASA is the exclusive purchaser and transmitter of gas	Permission from the Minister is required before third party gas can be carried
Western Australia[a]	SECWA has exclusive rights for all gas undertakings. Private participation requires approval from the Governor, based on recommendations from the Minister and SECWA	Sale of LPG is not permitted in areas in which natural gas is distributed without permission from SECWA
Northern Territory	ni	Licence required
Distribution		
New South Wales	Trading rights accorded by on-going Authorisations, valid for an initial period of 10 years, with a minimum of 10 years notice of revocation	Licence required
Queensland	Conditional franchises apply: there is provision within the Act for gas to be supplied within a franchise area by parties other than the franchise holder	Licence required. Voluntary tolling arrangements exist.
South Australia	ni	Licence required
Northern Territory	Exclusive franchise arrangements in defined areas	Licence required
ACT	Exclusive franchise applies	Licence required

[a] In Victoria and Western Australia, restrictions on entry are the same for both the transmission and distribution.
Ni = Non identified
Source: Information provided in submissions and/or by gas organisations in response to a Commission questionnaire

Transmission

In Victoria, South Australia and Western Australia, gas utilities are accorded exclusive rights to transmit gas. An alternative supplier may only operate with the approval of the government (such approval has been granted in Western Australia). According to its Principal Act (s. 67), GFCV 'has the exclusive right to transmit and supply gas by reticulation in Victoria' (s. 67). SECWA's Principal Act (s. 55) places similar restrictions on competition:

> ... no new gas undertakings shall be established by any local or other authority, or any person, other than the Commission, unless approved by the Governor pursuant to a recommendation of the Minister after consultation with the Commission.

In South Australia, the monopoly position of PASA is sustained through government policy rather than legislation. As the sole purchaser of natural gas for use in the State and the sole supplier of gas to distributors, the Authority 'assumes a key role in negotiating purchase agreements for natural gas usage in South Australia' (Sagasco, sub. 46, p. 30). The only instance in which the Government will allow an alternative supplier is if South Australia stands to benefit. A recent proposal by Sagasco to operate a South Australian transmission pipeline (Katnook) was rejected by the Government and awarded to PASA on the grounds that it was better placed to serve the interests of the State. Sagasco also indicated that before any new contracts with gas producers are finalised, approval from the Office of Energy Planning and PASA is required.

In other States and Territories the situation is as follows:

- New South Wales and the ACT - there is no legislative barrier preventing an organisation other than TPA from transmitting gas. No common carriage provisions apply to TPA, although there is no formal requirement preventing TPA from hauling third party gas.

- Queensland - all private pipelines must be licensed. The Principal Act requires that a licensee accept and discharge the obligations of a common carrier. The Queensland Government owned pipeline is formally exempt from this provision.

- Northern Territory - private pipelines are required to be licensed. The Minister may direct the licensee to carry third party gas.

Distribution

The distribution of gas is undertaken within franchise areas. Most private utilities, and GFCV, claim that current franchise arrangements do not preclude competition from an alternative supplier, provided they meet the licensing requirements. Apart from Queensland, however, gas in each state is supplied by a sole distributor or, in the case of New South Wales, by a group of associated distributors.

Once a distribution licence has been granted, the gas utility will often receive an on-going right to supply gas. In the case of private utilities, this licence may be revoked if certain pre-determined conditions are not adhered to.

In New South Wales, for example, AGL may have its Authorisation revoked after receiving 10 years notice, or immediately if it contravenes a condition of its licence. In addition to revoking licences, some governments also have the power to allow an alternative distributor to supply gas. In Queensland, if the incumbent does not adhere to the provisions of the licence, it may be rescinded or an alternative supplier allowed to reticulate within the franchise area. The Principal Act (s. 14) states that where:

> ... it appears to the Governor in Council that the holder of a franchise is unable or unwilling to supply gas to a particular consumer in the franchise area at a price or on terms and conditions that are reasonable and acceptable to the consumer, the Governor in Council may authorize any person to supply gas in the franchise area.

In most states and territories, there are no provisions for open access or common carriage through the utilities' distribution network. In New South Wales, the Minister has a limited ability to amend an AGL authorisation so that it includes a provision for common carriage. According to the Gas Act (s. 17), this action can only be taken if the Minister considers the amendment would:

> (a) be in the best interests of all affected gas users;
>
> (b) create competition in the markets for the sale of wellhead gas and the haulage of gas; and
>
> (c) not prejudice the conveyance of gas needed by the gas distributor to supply its customers and meet its contractual obligations.

Distribution utilities in Queensland are required to carry third party gas under voluntary 'tolling arrangements'. Unlike common carriage , where a gas utility is required by law to carry another party's gas, this arrangement leaves such a decision to the discretion of the incumbent.

The nature of government controls over the business operations of gas utilities is closely related to the degree of public ownership. Similar to the electricity industry, much of the administration and operation of public gas utilities in Victoria, South Australia and Western Australia is subject to legislation and government policy. For private gas utilities, operating controls tend to be more specific in nature and are chiefly directed at preventing abuses of market power associated with their trading licences.

The main areas in which operating controls are imposed on gas utilities include:

- borrowings;
- budgetary controls and investments;
- shareholding restrictions;
- exemptions from taxes and charges;

- board appointments;
- licensing fees; and
- pricing arrangements.

Borrowings

As detailed in Table 3.9, government restrictions on borrowings only apply to public utilities. These restrictions extend to limits on borrowings, provision of loan guarantees and determination of the terms and conditions of loans.

All public utilities are restricted in their borrowing capabilities. The ALC effectively restricts the funds that can be raised by a public utility by imposing borrowing limits on their respective state or territory government. In the case of TPA, the ALC may impose an actual - rather than indirect - limit on borrowings, although this option has yet to be exercised.

Some relief from standard ALC limits has been possible in Western Australia. Since 1985-86, the ALC has provided a special addition to the State global borrowing limit to fund SECWA's accumulated gas inventory from the North West Shelf project.

In the case of Sagasco, its parent company, SAGASCO Holdings (which is predominantly State Government owned), is indirectly bound by the State's borrowing limit. However, the South Australian Government stated that it:

> ... believes that public companies listed on the Stock Exchange that are subject to the Companies Act, such as SAGASCO Holdings, should be removed from the ambit of the global borrowing limits.

A government guarantee on loans applies to all public gas utilities. This is usually specified in the Principal Act. For instance, Section 14 of PASA's Principal Act states:

> ... repayment of all principal sums so borrowed by the Authority and the payment of all interest secured by any debenture issued by the Authority is hereby guaranteed by the Government of South Australia.

TPA and PASA pay a fee for the provision of a government guarantee, while GFCV and SECWA do not. Sagasco does not receive an explicit Government guarantee on its borrowings and it currently does not have any Government loans. However, SAGASCO Holdings stated that submission (sub. 46, p. 12), it has 'been able to minimise financial costs by retaining Government involvement through its shareholding'. This suggests that majority Government ownership of the parent company is therefore providing Sagasco with an implicit government guarantee.

Table 3.9: **Gas utilities' borrowing environment**

Utility	*Restrictions*	*Explicit loan guarantee*	*Terms of government loans*
TPA	The Australian Loan Council may limit the level of funds raised through the Commonwealth and the private sector	Yes, incurs a charge of 0.125 per cent	Determined by the Minister for Finance
GFCV	Explicit limit on borrowings. Approval from Treasury required	Yes, but no charge applies	Determined by the Department of Treasury
PASA	Funds raised require approval from the Treasurer	Yes, charge included in interest rate	Determined by South Australian Financing Authority
SECWA	Amounts and composition of loans determined by Treasury	Yes, but no charge applies	Determined by Treasurer

Source: Information provided in submissions and/or by gas utilities in response to a Commission questionnaire.

The terms for government loans by public gas utilities are determined by the government or the state financing authority. Under TPA's Principal Act (s. 25), for instance,

> ... the Minister for Finance may ... lend money to the Authority on such terms and conditions as the Minister for Finance, in writing, determines.

Apart from general financial regulations, governments are not involved with private gas utilities borrowing activities.

Budget controls and investments

Most public utilities are required to invest all surplus funds with the government and seek government approval for investments. Under SECWA's Principal Act (s. 113), for example, all monies standing to the credit of SECWA may be 'temporarily invested in such categories of investment as the Treasurer of the State may approve'. All funds accrued by TPA under the Pipelines System Deed are subject to control by the Federal Minister for Finance. Profits made outside this agreement, which come from operations at Canberra and Oberon, are not subject to Ministerial control. The Authority is unable to build and/or operate pipelines without owning them. TPA is also unable to employ its skills and knowledge outside of Australia

Governments may also control the areas in which public gas utilities invest. For instance, SECWA must acquire approval from the Minister for contracts worth in excess of $2 million. For TPA, this figure is $500 000. Investments by the GFCV are bound by the *Borrowing and Investment Powers Act 1987*. Under the Act, the Treasurer deems specified investments that can be undertaken by GFCV. In addition to these specified areas, the GFCV may (s. 20):

> ... with the approval of the Treasurer, invest moneys of the authority in any manner approved by the Governor in Council on the recommendation of the Treasurer in relation to the authority.

Shareholding restrictions

For mixed equity or private utilities, there is sometimes legislation restricting the level of shareholding by an individual or company. For example, the *Gas Suppliers (Shareholding) Act 1972* restrict shareholdings in Allgas Energy Ltd to 12.5 per cent of the company's voting shares. Such restrictions afford the private utilities a concession similar to that of the public electricity authorities - virtual immunity from takeover. Table 3.10 summarises these restrictions.

Table 3.10: **Shareholding restriction on gas distribution utilities**

Utility	*Restriction*
AGL	Maximum of 5 per cent of issued share capital for any individual/organisation
GFCV	Trading limited to '6% B' preference shares, which represent 27.5 per cent of issued share capital
Allgas	Maximum of 12.5 per cent of shares for any individual/organisation
Sagasco	Shares in the gas company can only be sold following approval from SAGASCO Holdings Ltd shareholders

Source: Various Acts and utilities' annual reports.

Exemption from taxes and charges

Public gas utilities are exempt from a range of taxes and charges. A list of the main taxes and charges applying to all major gas utilities is outlined in Table 3.11.

Exemption of public utilities from major taxes and charges places private gas utilities at a significant disadvantage in terms of competing with both public gas suppliers and electricity authorities. This was noted in AGL's submission (sub. 31, p. 41) to the inquiry:

> ... we request that action be taken to create an "even playing field" by requiring that both gas and electricity distributors bear the same Government charges in respect of Company Tax, Local Government Rates and Taxes, Sales Taxes [and] Payroll Tax.

Board appointments

Government involvement in employment varies across utilities. For example, board members of TPA, PASA and SECWA are appointed by the Governor General or the respective State Governor. One of the six members appointed to the board of TPA is nominated by AGL, although the Governor General is under no obligation to appoint AGL's nominee.

The several State Government appointees on the GFCV board is a result of a legislative requirement and the fact that the Government owns over half the preference shares - the holders of which elect the remainder of the board. This arrangement results in a close 'working relationship' between the GFCV and the Victorian Government, whereby the general manager of GFCV usually meets with the Minister on a regular basis.

Table 3.11: **Government taxes and charges payable by gas utilities**

	Commonwealth taxes and charges				*State and territory taxes and charges*		
Authority	*Income tax*	*Fringe benefits*	*Sales tax*	*Excise*	*Payroll*	*Other*[a]	*Local government rates & charges*
TPA	no	yes	no	yes	yes	no	yes[b]
AGL (NSW)	yes	yes	yes	yes	yes	yes	yes
GFCV	no	yes	no	no	yes	yes[c]	yes[c]
Allgas Energy Ltd	yes	yes	yes	yes	yes	yes	yes
Gas Corporation of Qld	yes	yes	yes	yes	yes	yes	yes
PASA	no	yes	no	yes	yes	yes	yes
Sagasco	yes	yes	yes	yes	yes	yes	yes
SECWA	no	yes	no	yes	yes	no	yes[d]
NT Gas Pty Ltd	yes	yes	yes	yes	yes	yes	yes
AGL (ACT)	yes	yes	yes	yes	yes	yes	yes

[a] Includes land tax, state excise and state stamp duty on mortgages, cheques, conveyances etc., but not bank charges.
[b] Ex gratia payment in lieu of charges.
[c] GFCV pays land taxes and local rates on commercial facilities.
[d] SECWA only pays local rates on employee houses, but water rates on all property.

Source: Information provided in submissions and/or by gas utilities in response to a Commission questionnaire.

Despite being the majority shareholder in the parent company, the South Australian Government is represented by only one director on the board of SAGASCO Holdings, although it is directly involved in major decisions which require a shareholders' vote.

Licensing fees

To cover the cost of regulation associated with franchises, private gas utilities are required to pay licensing fees as follows (see Table 3.13 for the amounts payable):

- AGL must contribute one per cent of sales revenue to the New South Wales Government. Approximately 25 per cent of this covers the cost of administering the legislation governing AGL's operations and the operation of the Gas Council. The remainder goes to consolidated revenue;
- gas distributors operating under franchises in Queensland are liable for an annual licensing fee. The fee is $55 per year plus $10.30 for each 100 GJ of gas supplied. Gas supplied to customers who take more than 50 TJ in a six months, are not included in this calculation;
- Sagasco contributes five per cent of gross revenue derived from its gas licence; and
- gas distributors in Alice Springs pay the Northern Territory Government a fixed fee. Once the utility's operating surplus is enough to cover all costs including accumulated losses, it may be liable for a further fee.

Pricing arrangements

A variety of pricing arrangements apply to the transmission and distribution of gas. Details surrounding the pricing arrangements for gas utilities are summarised in Table 3.12. The government's role in price setting is generally less intrusive for private utilities than it is for government authorities. Unlike that for public utilities, the primary role of the government with respect to private utilities is usually to monitor, rather than to set prices. However, management of both public and private utilities are free to negotiate contracts directly with large industrial and commercial consumers.

Pricing arrangements are examined on a state-by-state basis, grouping together states and territories for which the situation is similar. Discussion begins with those states in which government involvement is the most pronounced.

- **Victoria and Western Australia**

In the case of GFCV and SECWA, tariffs are effectively set by the utility's board and then approved by the minister. In Western Australia, SECWA is required to submit proposed annual tariff increases and/or changes to its tariff structure to the Government. These tariffs are published following approval by the Government. In Victoria, GFCV, according to their submission (sub. 26, p. 8), must set tariffs:

Table 3.12: **Government involvement in tariff arrangements for gas organisations**

State/Territory	*Procedures established by government*	*Government guidelines*
Transmission		
New South Wales and ACT	ni	ni
Victoria[a]	Annual change are set by the GFCV, subject to approval by Government	Increases should be less than CPI and reduce cross-subsidies between market sectors
Queensland	ni	Minister may request the Pipelines Tribunal to investigate transportation charges
South Australia	Determined by PASA, subject to approval by the Minister	Government objective to maintain tariff increases below CPI
Western Australia[a]	Tariffs set by SECWA, subject to Government approval. Major tariff adjustments require approval from Cabinet	Government commitment to keep tariff increases below CPI
Northern Territory	Government approval of tariff changes required in some circumstances. If a pipeline refuses to carry third party gas, the Minister has the right to set tariffs for such gas	ni
Distribution New South Wales	Pricing for tariff customers subject to CPI-X regulation. Pricing for non-tariff customers determined by AGL with regular review by the Gas Council	Pricing for all customers is monitored by the Gas Council
Queensland	Must notify the Minister and the public (4 weeks in advance) of any tariff changes	Minister may request the Gas Tribunal to investigate tariffs
South Australia	Sagasco submit tariff changes to the South Australian Commissioner of Prices. Approval from the Minister, following a recommendation from the SACP, is required	Subject to rate of return regulation
Northern Territory	ni	Subject to rate of return regulation
ACT	Ministerial approval for price increases is required	ni

[a] In Victoria and Western Australia, the pricing arrangements are the same for the transmission and distribution of gas
ni = Non identified

Source: Information provided in submissions and/or by gas organisations in response to a Commission questionnaire.

> ... to ensure they are stable, predictable, competitive with those interstate and at a level high enough to cover costs and generate Government dividends.

These two authorities are free to negotiate contracts with large consumers outside normal tariff arrangements, although they are not generally available for public scrutiny.

- **South Australia and the ACT**

In South Australia, there are different pricing arrangements for the distribution and transmission utilities. The price paid by Sagasco for gas comprises the average price of gas purchased by PASA from the Cooper Basin, plus a transportation fee. Under its Principal Act, PASA may (s. 10):

> ... make such charges and impose such fees for the conveyance or delivery of petroleum or any derivative thereof through any such pipeline as it may, with the approval of the Minister, determine.

According to the South Australian Government, this haulage fee reflects 'as near as practicable the actual cost of transporting the gas to the various delivery points throughout the State'.

Tariffs for gas distributed by Sagasco are bound by a maximum price, while changes are made in accordance with the following process:

- Sagasco make a submission (usually annually) to the Minister suggesting changes to the current tariff arrangements;
- the Minister directs the South Australian Commissioner of Prices (SACP) to conduct a review of the maximum prices which should prevail under the Act; and
- following a recommendation from the SACP, the Minister may adjust the maximum price of gas that can be charged by Sagasco.

Sagasco's tariffs are also restricted by rate of return regulation. According to the Principal Act (s. 25), if Sagasco's profit:

> ... exceeds the prescribed amount, the excess must be transferred to a separate account (the "statutory reserve account")... Money from this statutory reserve account must not be dealt with except as authorised by the Minister.

The 'prescribed amount' is currently set at the long-term bond rate plus 2 per cent. However, the gas company has yet to reach this amount and is presently achieving a level around 2 per cent below the long-term bond rate.

A similar but less complex arrangement for tariff setting exists in the ACT: AGL must seek approval from the responsible Minister for any changes in tariffs.

- **Northern Territory**

In the Northern Territory, the majority of gas is sold under privately negotiated contracts. The need for Ministerial involvement only arises if negotiations between the pipeline owner and a third party gas owner break down.

In this case, the Minister will set an appropriate tariff.

Prices in Alice Springs for distributed gas are controlled by rate of return regulation. Under legislation, the rate of return earned annually by gas distributors in the Northern Territory must not exceed 20 per cent.

The price of LPG transported by road in the Northern Territory is subject to possible review by the Prices Surveillance Authority.

- **New South Wales**

The pricing arrangement for gas transmitted by TPA to NSW is controlled by a contractual agreement struck between the Federal Government and AGL. Under the Pipeline System Deed, AGL has assured TPA of full cost recovery - including interest, but excluding a return on capital employed - over the term of the agreement.

The tariffs for gas distributed by AGL within New South Wales have recently come under a new monitoring regime. As of 20 July 1990, AGL has been required to price gas according to a CPI-X formula. The formula automatically passes on variations in the cost of gas supplied to AGL and limits non-gas cost increases to the CPI less an efficiency factor 'X'. It covers all customer groups to which published tariffs apply. The 'X' has been set at 2 in Sydney and Wollongong and 3.5 in Newcastle. The higher figure in Newcastle seemingly reflects the expected efficiency gains and economies of scale that can be achieved using the newer gas line to Newcastle. Although the Government is not involved in non-tariff pricing arrangements, its monitoring agency, the Gas Council, regularly reviews prices offered by AGL in the contract market.

- **Queensland**

In Queensland, the Government relies on self-regulation of the industry. It does not set prices for the haulage and distribution of gas. Increases in gas tariffs do not need approval by the Minister, but he/she must be advised in advance of any pending changes. In addition, changes to tariffs must be published four weeks in advance.

According to the Government (sub. 27, p. 10), this arrangement:

> ... allows the gas suppliers to operate freely as commercial enterprises, but with the Government reserving the right to intervene if deemed desirable.

If the Minister deems it necessary to intervene, he/she may request the Governor in Council to empower either the Pipelines Tribunal or the Gas Tribunal to inquire and report into various matters relating to the business and charges of a pipeline licensee or gas distributor, respectively. The inquiry has the power to address the pricing arrangements for both tariff and contract customers.

3.2.5 Performance measures

As is the case with electricity, public gas utilities are subject to a range of performance measures. These include periodic reviews of efficiency, annual reports and financial and non-financial targets. Government monitoring of the performance of private utilities varies but generally covers compliance with franchise, pricing and rate of return controls. A list of targets and contributions can be found in Table 3.13.

Financial targets

GFCV and SECWA are the only public gas utilities to have established financial targets with their respective Governments.

Under the *Public Authorities (Dividend) Act 1983*, GFCV (and SECV) must achieve a real rate of return on their assets (defined as the written-down replacement cost of assets in service) of at least four per cent. On this basis, GFCV achieved a return of 8.5 per cent in 1989-90. The financial targets discussed in section 3.1.5 also apply to SECWA's gas operations.

The only public utility required to provide a formal dividend to the government is GFCV. In addition to the normal dividend to its preference shareholders, GFCV, under the *Public Authorities (Dividend) Act 1983*, must also provide a return of up to five per cent on public equity. In 1989-90 the dividend was $46.9 million, of which $43.2 million went to Consolidated Revenue and the remainder to the Victorian Equity Trust. This represents a return on equity for the people of Victoria of five per cent.

Other contributions made by public gas utilities include:

- under the *Public Authorities (Contribution) Act 1983*, GFCV has to contribute 30 per cent of gas sales revenue to the Government. This contribution is a result of the favorable prices GFCV pays for gas from the Bass Strait. The levy attempts to create a more realistic field-gate price for gas and, in 1989-90, amounted to $253 million;
- PASA contributed $1.1 million to the Government in 1989-90; and
- SECWA is liable to contribute three per cent of revenue from metered sales of gas.

Non-financial targets

Although most gas utilities have non-financial targets, only SECWA has established such targets in consultation with its State Government. These targets are intended to assist the Government to assess SECWA's performance against the targets.

Table 3.13: **Gas utilities' financial targets and government contributions payable, 1989 - 90**

Organisation	*Financial target*	*Amount ($ 'million)*	*Contributions*	*Amount ($ 'million)*	*Other*
Transmission					
TPA	ni	-	ni	-	ni
GFCV	Minimum real rate of return on written down replacement cost of assets (currently at 4 per cent)	146.7 [a]	Dividend of up to 5 per cent of public equity [b] 30 per cent of sales revenue contributed to Consolidated Revenue	46.9 [c] 253	ni
PASA	Break-even operating result	-	Contribution to the Government	1.1	ni
SECWA	Return on revenue (4.5%) [d] Return on assets (2.2%_ Debt-equity ratio (100%) Face cash flow ratio (@$%) Costs to assets ratio (45%)		3 per cent levy applies to certain metered sales of gas	9	A range of non-financial targets under the performance agreement
Distribution					
AGL (NSW)	ni	-	One per cent of gas revenue as an Authorisation fee [e]	na	ni
Queensland -					
Allgas Energy Ltd	ni	-	Licensing fees	0.5	ni
Gas Corporation of Qld	ni	-	Licensing fees	0.6	ni
Sagasco	ni	-	5 per cent levy applies to all gas sales	6.7 [f]	Profits in excess of prescribed limit may be transferred to a reserve
Northern Territory	ni	-	Distributors are liable for fixed and variable annual fees [g]	na	ni
AGL (ACT)	ni	-	ni	-	ni

a This represents a real return on the average assets-in-service of 8.5 per cent

b Public equity defined as current value of operating assets less associated debt.

c Of the $46.9 million, the Government will reserve $43.2 million and the Victorian Equity Trust $3.7 million. This represents a return on public equity of 5.0 per cent.

d All Bracketed figures are targets for 1992 - 93

e An Authorisation fee for 1989-90 did not apply

f This figure is the licence fee for the 1990 calendar year.

g Distributors are only liable for the variable fee once their accumulated cash flows (which include negative flows) have recovered all costs.

ni = Non identified; na = Not available.

Source: Information provided in submissions and/or by gas utilities in response to a Commission questionnaire.

Performance monitoring for private organisations

In a number of instances, governments have established monitoring agencies to observe and assess the performance of private gas utilities. The most prominent are the Gas Council in New South Wales and the Gas and Pipelines Tribunals in Queensland.

Under the amended Gas Act in NSW, the Gas Council has the power to monitor all aspects of AGL's operations against a range of duties specified in its Authorisations. If the Gas Council ascertains that AGL has contravened the conditions of its Authorisation, it has the power, with the approval of the Minister, to add or amend any of the provisions within the Authorisations. In addition, the Minister has the power to revoke the Authorisation without compensation. If AGL has serious reservations about the changes it can request the Minister to establish a Review Panel to assess the changes. Apart from ongoing scrutiny by the Gas Council, the Minister may revoke an Authorisation, after providing 10 years notice and following passage of the initial 10 years of the licence.

The monitoring arrangements in Queensland are somewhat different to those in New South Wales. The major differences include:

- the Government and the Minister, rather than a separate government agency, monitor the gas utility's operations. The Pipeline or Gas Tribunal is only active at the request of the Minister, following evidence regarding 'serious matters such as abuse of market position'; and

- the guidelines used by the Tribunals to assess a utility's performance are more general than in New South Wales. Instead of specific guidelines on pricing, such as those attaching to CPI-X, the Tribunals must consider a range of parameters when assessing a utility's prices.

Monitoring of gas distributors in Queensland was made easier by recent pro-competitive amendments to the Principal Act. The changes limit the exclusive franchise to the reticulation system alone. Apart from gas distributed through this system, alternative suppliers are allowed to sell gas (usually LPG) within the franchise area.

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Attachment 3.1: Electricity authorities and their Principal Act

State/Territory	*Electricity authority*	*Principal Act*
Cwlth	Snowy Mountains Hydro-Electric Authority (SMHEA)	*Snowy Mountains Hydro-Electric Power Act 1949*
NSW	Electricity Commission of NSW (ECNSW)	*Electricity Commission Act 1950-1982*
	Electricity Councils	*Electricity Act 1945 & Local Government Act 1919*
Vic	State Electricity Commission of Victoria (SECV)	*State Electricity Commission Act 1958-1988*
Qld	Queensland Electricity Commission (QEC) & Regional Electricity Boards	*Electricity Act 1976-1989*
SA	Electricity Trust Of South Australia (ETSA)	*Electricity Trust of South Australia Act 1946-1988*
WA	State Energy Commission of Western Australia (SECWA)	*State Energy Commission Act 1979-1987*
Tas	Hydro-Electric Commission (HECT)	*Hydro-Electric Commission Act 1944-1988*
NT	Power and Water Authority (PAWA)	*Power And Water Authority Act 1987*
ACT	ACT Electricity and Water Authority (ACTEW)	*Electricity And Water Act 1988*

Attachment 3.2: Gas organisations and their Principal Act

State/Territory	*Principal Gas Organisation*	*Principal Act*
Transmission		
NSW & ACT	The Pipeline Authority (TPA)	*The Pipeline Authority Act 1973*
Vic [a]	Gas and Fuel Corporation (GFCV)	*Gas And Fuel Corporation Act 1958-1987*
Qld	AGL Petroleum	*Petroleum Act 1923-1988*
SA	Pipelines Authority of South Australia (PASA)	*The Pipelines Authority Act 1967-1985*
WA [a]	State Energy Commission of Western Australia (SECWA)	*State Energy Commission Act 1979*
NT	NT Gas Pty Ltd	*Energy Pipelines Act 1981*
Distribution		
NSW	Australian Gas Light Gas Companies (AGL)	*Gas Act 1986-1990*
Qld	Gas Corporation of Queensland & Allgas Energy Ltd	*Gas Act 1965-1990*
SA	South Australian Gas Company Ltd (Sagasco)	*Gas Act 1988*
NT	Centregas Pty Ltd	*Dangerous Goods Act 1985*
ACT	Australian Gas Light Gas Company (AGL)	*Draft Gas Ordinance 1987*

[a] These utilities are responsible for transmission and distribution in their States. The Principal Act covers both activities.

APPENDIX 4: RECENT INITIATIVES BY GOVERNMENTS/AUTHORITIES TO IMPROVE THE EFFICIENCY OF THE ELECTRICITY AND GAS SUPPLY INDUSTRIES

Coupled with a commitment to increase the efficiency of their utilities, governments have introduced a variety of reforms to the institutional and regulatory environment of the ESI and NGI. This process has involved a range of measures used to assess their performance. However, the degree of progress achieved and the resolve of governments to implement change varies considerably across states/territories.

In recent years, most governments in Australia have implemented or foreshadowed changes to the institutional and regulatory environment of their electricity and gas industries with the aim of improving their performance. As part of this inquiry, the Commission invited governments and/or their authorities to provide information about these changes and their underlying motivation.

This appendix provides a brief overview of the information provided in response to this invitation. The overview commences with initiatives taken by the Commonwealth Government and its authorities, followed by those of state/territory governments and their authorities.

4.1 Commonwealth

Comments covering recent initiatives in areas involving the Commonwealth Government were received from the SMC and the SMHEA in relation to the electricity industry and TPA in relation to natural gas.

4.1.1 Electricity

The Snowy Mountains Scheme serves the dual purposes of supplying electricity, mainly for peak load, and water for irrigation. It was constructed by the SMHEA and funded by the Commonwealth. Responsibility for the direction of the operation and maintenance of the Scheme is vested in the SMC. However, in a number of areas, notably strategic management and refurbishment of assets, it is unclear where the respective responsibilities of the SMC and SMHEA lie.

According to the SMC's submission, these matters are being addressed by the SMC. They are also being examined in a joint Commonwealth, New South Wales and Victoria review of the Scheme. This review will also examine the Scheme's financial and institutional arrangements and, on the suggestion by the New South Wales Government, the possibility for the States to increase their equity in the Scheme.

Operating efficiency

A number of actions are being taken to raise the efficiency of the Scheme, these include:

- developing a corporate plan based on clearly defined performance criteria (eg plant availability, forced outage rate and real cost of production);
- more effective human resource planning and skills development;
- establishing cost centres to promote greater accountability of managers;
- increasing the use of contract labour - about 90 per cent of planned plant refurbishment will be performed under contract; and
- implementing the Industrial Relations Commission's structural efficiency principle.

In 1988, the SMC established a Review Group to evaluate long-term strategies for the maintenance and refurbishment of the Scheme's assets. The Group has sought an on-going assurance that plant refurbishment investments are evaluated on the same basis as that of the New South Wales and Victorian electricity systems. This process has recently been applied to the planned refurbishment of Tumut 1 and Tumut 2 Power Stations and associated works. Non-core activities (eg canteens, housing, township services, public relations and tourism) are being reviewed to reduce or eliminate them.

4.1.2 Gas

TPA owns and operates the Moomba to Sydney pipeline and related spur pipelines within New South Wales. It carries, mainly on a cost of service basis, gas which AGL has contracted to buy from the Cooper Basin Producers.

Organisational changes

According to TPA, it was advised in July 1988 that the Commonwealth Government was undertaking a review of its Statutory Authorities and Government Business Enterprises with a view to improving their efficiency and ensuring that they earn an appropriate rate of return. The Authority lodged a reform package with the Minister which was substantially accepted, though has not as yet been implemented. The reform package provides for the Authority to:

- build and/or operate pipelines without being obliged to own them;
- form subsidiary companies and/or enter into joint ventures;

- undertake commercial activities outside the scope of the pipeline system deed; and
- engage in such activities outside Australia.

While waiting for legislation to implement the reform proposals, TPA prepared its corporate plan based on its functions under existing legislation.

Sale of the pipeline

In the 1989-90 Budget, the Commonwealth Government announced its intention to sell the Moomba to Sydney pipeline before the end of 1990-91. The Government also intended to legislate to allow the operations of the pipeline to be put on a proper commercial basis prior to its sale (Joint Press Release, Minister for Finance and Minister for Resources 1990). Under current arrangements with AGL, TPA cannot earn a profit on the bulk of its operations. Proposed legislation provided for the haulage tariff to be increased by 25 per cent from January 1991 and by a further 25 per cent from January 1992 on those sections of the pipeline system where the current haulage tariff has no profit component. The Government also envisaged that, prior to sale, legislation would be introduced to prevent the exploitation of monopoly profits by the new owner . In December 1990, the Government's Bill on this matter was rejected by Parliament and, in April 1991, the pipeline was withdrawn from sale.

4.2 New South Wales

Information on initiatives to improve the performance of the electricity and gas industries in New South Wales was prepared by various parts of the energy industry and submitted by the New South Wales Government. The ECNSW prepared the section on the generation and transmission of electricity; the Electricity Council of New South Wales prepared the section on electricity distribution; and the Department of Minerals and Energy prepared the section on the gas industry.

4.2.1 Electricity

The ECNSW is to be corporatised during the 1990-91 financial year. In recent years, the ECNSW has implemented management policies, consistent with the Government's desire for corporatisation, which have reduced operating costs saving by more than $80 million per annum. These savings have been achieved through: improved work practices (eg shift work for maintenance crews and contracting out of plant maintenance); reduced employment (a decline of about 34 per cent from over 10ÿ994 in 1986-87 to 7ÿ260 in 1989-90); enhanced plant performance (since 1985-86, system availability has increased from 62 to 75 per cent); improved thermal efficiency resulting in significant reductions in fuel usage per KWh; the retirement of uneconomic plant at Tallawarra and Vales Point A Power Stations, saving $81 million annually; and reduced, in real terms, coal prices through the rationalisation of coal mine assets and increased reliance on private sector coal supplies.

Other recent initiatives which have impacted on ECNSW include:

- a Strategic Plan aimed at improving organisational performance, a Corporate Plan with business oriented performance indicators, Group Business Plans and moves to separate the financial accounting records of the ECNSW's generation and transmission functions;

- labour market reforms involving a training, efficiency and multi-skilling plan to provide the basis of a single award for ECNSW employees (approved in February 1991), as well as broadbanding and promotion by merit;

- a new Bulk Supply Tariff (BST) which is more reflective of supply costs and includes a supply charge and an energy charge: the latter has two components - time-of-use and voltage;

- more active encouragement to private generators of power (including cogenerators). In response to an invitation in late 1988 for private firms to submit proposals for the production of electricity from alternative sources, Gunnedah Power Company is continuing to negotiate with the ECNSW to supply electricity to the New South Wales grid;

- greater interstate cooperation; such as, joint planning studies to explore opportunities for interconnection with other States (eg Queensland); and

- stronger commitment for research into renewable technologies (eg the ECNSW, in conjunction with CSIRO, is investigating sites for wind farms and is also supporting research into photo-voltaics at the University of New South Wales).

As a result of the reforms to operating practices, real operating costs per unit of electricity generated declined by 7.6 per cent between 1988-89 and 1989-90.

Electricity distribution

The distribution segment of the ESI in New South Wales comprises a statutory authority and 24 local government authorities (21 are county councils) which purchase bulk electricity (primarily from the ECNSW) and retail it to consumers throughout the state. Issues being addressed by the distribution councils include:

- developing more commercially oriented organisations through a more business-oriented approach to marketing electricity;

- controlling costs through human resource management, productivity, and operational efficiency, via closer scrutiny of the utilisation of all resources;

- cost effective use of contractors; and

- critically appraising the future service of aging system components which may require progressive replacement in the next decade.

Performance agreements

Following a review of all distribution councils in 1988-89, the Minister for Minerals and Energy negotiated Performance Agreements with each distribution council. The agreements were introduced to place the councils in a more commercial environment of autonomy, accountability and self regulation. The agreements specify targets in a number of areas to encourage further improvement.

Changes to retail tariff

Recent initiatives have sought to make retail tariffs more reflective of costs and the BST, and to reduce cross-subsidies between or within tariffs to acceptable levels. On the recommendation of a review of electricity tariffs (New South Wales Government 1989), the demand component of retail tariffs has been abolished and a fixed charge introduced, along with modifications to a time-of-use energy structure.

Improvement in operating performance

The performance of the electricity distribution sector has been improved through:

- a 10.7 per cent reduction in staffing numbers from 17 473 in 1986-87 to 15 600 in 1989-90. A further reduction of more than 1 250 is anticipated by 1992-93;

- increased labour productivity, reflected by a 23 per cent increase in the customer-employee ratio to 155. It is anticipated that current productivity strategies should further improve this ratio to 181 by 1992-93. The four major distributors which supply 80 per cent of customers within the state are targeted to achieve a customer-employee ratio of 200 by June 1994; and

- a decrease, in real terms, in average electricity prices by 23 per cent since 1983 - a further reduction of 9 per cent is anticipated by 1992-93. The councils are targeting tariff increases to be no more than half the CPI increases over the next three years.

4.2.2 Gas

The legislation regulating the gas distribution industry in New South Wales was substantially changed following a Ministerial Working Party (1989) review. The changes were aimed at promoting competition within, and improving the efficiency of, the gas distribution industry. The legislation seeks to:

- minimise government involvement in the gas distribution industry while protecting gas consumers from monopoly pricing practices by a price capping arrangement;

- utilise regulations which are more responsive to the needs of industry and government;
- reduce the administrative costs of regulation by replacing licenses with authorisations;
- increase the incentive for gas utilities to improve efficiency by minimising the costs of service; and
- promote competition and reduce barriers to entry by allowing some possibility for controlled third party access to gas transmission and distribution/reticulation systems at fair prices.

Gas Council

The Gas Council of New South Wales administers the new arrangements to ensure that regulations are responsive to the needs of the industry and to maintain a monitoring role in the interests of gas consumers. The Council is an independent regulatory body consisting of a chairperson and two part-time members appointed by the Minister.

Authorisations replace licensing

Annual licensing arrangements have been replaced by Authorisations. The Authorisations are valid for a minimum of twenty years - the Minister can notify an Authorisation holder after ten years of operation that he intends to revoke the Authorisation in ten years time. However, revocation can occur at any time if the holder does not comply with a direction of the Council to observe a condition of the Authorisation.

Authorisations are subject to a fee set at one per cent of the previous year's retail gas sales. Other conditions attached to the Authorisations are subject to direct negotiation between gas distributors and the Gas Council. If no agreement can be reached between the Council and a gas distributor, legislation provides for the appointment of a Review Panel to determine the issue(s).

Tariff setting reformed

Previous tariff setting arrangements and rate of return regulation limiting a gas utility's profit have been replaced by a price control formula based on the CPI minus an efficiency factor `X'. The price control formula will be incorporated within the Authorisations and will be monitored by the Gas Council. It is intended that the formula will only apply to published tariffs (customers using less than 10 TJs of gas per annum). However, if the need arises, the legislation enables the Gas Council to monitor and initiate price control of contract tariffs.

AGL initiatives

AGL has attempted to improve the efficiency of its operations through award restructuring, training of employees and the development of modern data bases and computer systems to assist management. Also, under the `Goldline' project, the gas distribution system in Sydney is being rehabilitated to reduce leakage, increase productivity and provide a more reliable service for customers in the region.

4.3 Victoria

Comments on initiatives to improve efficiency in Victoria were received from the SECV in relation to the electricity industry and the GFCV in relation to natural gas.

4.3.1 Electricity

Corporate strategy

The SECV's corporate strategy commits it to improve the value provided to customers, maximise the efficiency with which resources are utilised, keep price increases below the rate of inflation and develop the potential of the workforce.

The corporate strategy led to the implementation of the Production Improvement Program aimed at deferring construction of new capacity by extending the operational life of existing power stations. The objective was to gain a 15 per cent improvement in the generation capability of older brown coal plant by 1991; this was achieved during 1988-89.

Reviews of management, work practices and of customer services has resulted in extensive changes throughout the SECV; staff numbers have been reduced and activities have been delegated to line areas.

Corporate reform is expected to achieve the specific identification and costing of CSOs, and a more competitive environment by applying State taxes and charges at the same level as Commonwealth sales and corporate taxes.

Strategic business units

The SECV has been reorganised into three Strategic Business Units, namely the: Production Group, responsible for the production of energy; Power Grid Group, responsible for the transfer of energy; and Customer Service Group, responsible for the distribution of energy and provision of services to customers.

This reorganisation has been undertaken to provide a clear business focus to the SECV's major activities, and to create a flatter structure to reduce hierarchical constraints, increase accountability, improve communication and decision-making, and broaden the opportunity for employee career development.

Additional structural change has taken place within each unit and corporate functions have been devolved, thereby making each unit fully autonomous. The reorganisation effectively ring fences the activities linked by market based transfer pricing.

Target rate of return

The SECV's financial statements are prepared on both a historical cost and real rate of return reporting basis. The real rate of return approach has supported the introduction of commercial business practices and improved resource allocation procedures.

The SECV is required to earn a minimum 4 per cent real rate of return on its net assets and to pay a dividend, to the Consolidated Fund, equivalent to a return on equity of up to 5 per cent. The return on assets target has been exceeded in each year since its introduction in 1983 and the dividend payout ratio has averaged 70 per cent of profit based on the historical cost of assets.

Labour productivity

Award restructuring and structural efficiency initiatives have been implemented to improve labour productivity. The number of awards have been reduced, a new pay structure implemented and better training and skills extension schemes developed.

Demand management

As a result of the findings of a study into demand management (SECV/DITR 1990), the SECV has allocated $55 million to a three year Demand Management Action Plan to advance 26 demand management programs.

Technology

The SECV is committed to the use of improved technology to increase economic efficiency and reduce adverse impacts on the environment. A Strategic Research Program has been initiated to focus on technologies for more thermally efficient generation of electricity from brown coal. New technology in the form of special control devices have extended the power carrying capacity of the existing network.

Improved performance

According to the SECV, the initiatives implemented to date have improved the performance of its operations through:

- a decline, in real terms, in controllable operating costs per unit of output by 40 per cent in the five years to 1989-90;

- an increase in the available capacity for base-load generating units (ie from 59 per cent in 1985-86 to 69 per cent in 1989-90);

- a fall in reserve plant margins from 45-50 per cent to 25-30 per cent; and

- a decline, in real terms, in average prices by over 3 per cent a year between 1985-86 to 1989-90.

Interconnection of state power grids

The New South Wales-Victoria interconnection is well established and transfers between the states around 600 to 1200 GWh per year. This interconnection has been enhanced by the establishment of a high transmission link between Victoria and South Australia which can carry in excess of 500 GWh per year. The SECV has recently entered into a 3 year contract with the ECNSW to supply Victoria with 300 MW of support and 1 000 GWh per year. This has enabled the SECV to defer the construction of Loy Yang B Units 3 and 4.

4.3.2 Gas

The GFCV is required to earn a minimum 4 per cent real rate of return on its net assets and to pay an annual dividend to consolidated funds. The rate of the dividend is determined by the Treasurer of Victoria and is not to exceed 5 per cent of its public equity.

To monitor and improve its operating efficiency, the GFCV has developed and instigated management techniques and reporting procedures. Among these initiatives introduced are Total Quality Management, which allows a continuous review and improvement of operations, improved reporting systems and new technology. This has enabled the GFCV to achieve, and better, the determined rate of return while complying with the requirement that price increases be limited to at least 1 per cent less than CPI increases. Also, over the past five years the GFCV has been able to:

- reduce, in real terms, tariffs by 18 per cent;

- increase the customer-employee ratio from 182 to 194; and

- reduce, in real terms, controllable operating costs per customer from $299 to $273.

Current initiatives include the establishment of a heatane gas department as a separate business entity to allow its performance to be evaluated against its private competitors and the contracting out of peripheral operations as economies are identified.

4.4 Queensland

The Queensland Government provided information on initiatives to improve the performance of the electricity and gas industries in that State.

Policy reviews

The Queensland Government is in the process of developing a corporatisation strategy for certain statutory authorities; including the ESI. A Green Paper has been released which canvasses the desirability of establishing public sector bodies in a form akin to public companies with their primary objective being to operate in a commercial manner. Mentioned as necessary requirements of a successful strategy were clarity of objectives; management autonomy and authority; strict accountability for performance; and greater competitive neutrality.

In addition, a Discussion Paper (Queensland Government 1991) has been released which outlines policy options to solve conflicts which may arise within an overall energy policy objective relating to economic efficiency, environmental impact, equity and state development. Suggested policy options include: corporatising the ESI; introducing efficient electricity pricing structures; interconnecting the Queensland and New South Wales electricity grids; encouraging cogeneration and private investment in the ESI; supporting further extension to the gas pipeline network; encouraging the use of renewable energy; and encouraging the use of energy efficient appliances and buildings.

Comments on both papers will be considered before any final proposals are developed.

4.4.1 Electricity

The electricity industry has implemented a number of initiatives to improve its performance. For many years this has involved competitive tendering for the supply of plant, equipment and fuel. Over the last 5 years, other initiatives have included:

- adopting a corporate strategy with associated performance;
- adopting a value management program to review plant designs and administrative systems;
- rationalising resource use through the closure of old, high-cost power stations and temporary closure of surplus capacity;
- labour market reforms involving the introduction of a single award for the ESI, reductions in staff numbers and reformed work practices (eg multi-skilling) - employment decreased from 13 194 in 1983-84 to 8 758 in 1988-89, a reduction of about 34 per cent;
- competitive tendering for equipment and fuel supply, rationalising coal supply arrangements, and using contractors to construct and maintain facilities.

Industry review

An External Strategic Audit of the industry examined a number of issues including strategic planning, performance indicators, extent and effect of non-commercial activities, management accountability, corporate structure, capital structure, capital budgeting, contracts and tenders, technical performance and barriers to competition. The report has been completed though it has not (yet) been publicly released.

In addition, a Task Force has completed a review the QEC's proposed Tully-Millstream hydro-electric project. The purpose of the review is to ensure that an investment will only be made when it is the most cost-effective and environmentally acceptable method of matching future demand and supply.

4.4.2 Gas

Deregulation

In 1988, the Gas Act was amended to increase competition in the gas market. Previous arrangements had given franchise holders the sole right to supply natural gas, and the majority of LPG, in defined areas. Under the new franchise arrangements, it is only the reticulation system which is protected and alternative suppliers can distribute bulk LPG in a franchise area. The amendments also removed restrictions on the business operations of utilities such as those relating to capital raising, profit distribution, dividend payments and pricing.

Voluntary `tolling arrangements' were introduced to encourage competition in the reticulation of gas. These arrangements allows third party gas to be carried by a reticulation system operator. It was acknowledged, however, that competitive pressure may be limited since the franchise holder sets the tolling terms. Where negotiations fail to agree on tolling conditions, another party may be allowed to build and operate a pipeline through the franchise area.

Common carriage

In 1988, the Petroleum Act was amended to allow all non-reticulation pipeline licensees (gas and oil) to become common carriers. While the Queensland State gas pipeline does not face a formal common carrier requirement, the Queensland Government said it would be unable to sustain a refusal to carry gas, or to exercise price discrimination over the private sector gas producers in Queensland.

Previously, a licensee was only required to become a common carrier on order from the Governor-in-Council. A Pipeline Tribunal has been established to deal, upon Ministerial request, with issues such as transportation charges, common carrier provisions, capacity and capacity expansion. The Government can, and does, own and enter contracts for private construction and operation of pipelines.

4.5 South Australia

The South Australian Government provided information on initiatives to improve the efficiency of the electricity and gas industries. SAGASCO Holdings provided information relating to the distribution of natural gas.

Policy reviews

A recently released Green Paper (South Australian Government 1991) canvasses a range of policy options to resolve conflicting issues which may arise in meeting the South Australian Government's stated role for the energy sector. This role encompasses the efficient and secure provision of energy while meeting the community's expectations relating to standard of living, social justice, economic development and environmental protection. Areas where policy choices were identified include: future energy sources; energy independence; energy efficiency; planning processes; structural change; and research and development funding for alternate energy sources. Public comment on these options has been sought prior to the further development of an energy strategy.

4.5.1 Electricity

A number of initiatives are currently being implemented to improve the performance of ETSA. These include:

- a corporate plan targeting customer services and improving the cost-effectiveness of activities. As part of this process, ETSA has instigated a program to create business units within the organisation, commercialise purchasing and supply activities, and enhance project management and control skills;
- restructuring electricity tariffs more directly to reflect supply costs, such as:
  - merging and simplifying industrial and commercial rates;
  - reducing off-peak rates for industry and farm use, and extending them to include the full weekend and a larger number of general purpose customers;
  - introducing an optional time-of-use demand tariff for customers with a demand of at least 300 KWh per year; and
  - reducing off-peak industrial tariffs to more closely reflect generating costs;
- a review, by ETSA, of opportunities to rationalise resource use and examine asset values, depreciation policies and specific guidelines for project evaluation;
- considering the use of target rates of return for ETSA and other public enterprises in South Australia; and
- evaluating, by ETSA and the Office of Energy Planning, the impact of selected demand management schemes on the South Australian electricity grid.

The pricing reforms will be progressively implemented, with the rate of change partly determined by the effects that price increases will have on particular customer groups. For instance, the cross-subsidy between domestic and small commercial customers (commercial tariffs are 70 per cent higher than comparable domestic tariffs) will be phased out over a 7-10 year period.

4.5.2 Gas

PASA, a semi-government authority, is the sole purchaser and transporter of natural gas within South Australia. It owns and operates the pipeline from Moomba to the metropolitan and regional areas. It purchases gas from the Cooper Basin producers and on-sells it, almost exclusively, to ETSA and Sagasco.

Sagasco is responsible for the reticulation of natural gas in the metropolitan and regional areas. Sagasco is a subsidiary of SAGASCO Holdings. The South Australian Financing Authority holds 79 per cent of SAGASCO Holdings' shares.

A number of initiatives are being implemented to improve the gas industry in South Australia, these include:

- an enhanced corporate planning processes, within PASA and Sagasco, reflecting new organisational goals;
- the progressive restructuring of gas tariffs to reflect more closely supply costs. Sagasco has introduced supply charges to reflect the fixed costs of supply, merged and simplified normal industrial and commercial rates, and has partly adjusted its rural tariffs to more closely reflect direct supply costs;
- restructuring PASA's transportation charges through a new method of allocating costs between customers. The new charges are aimed at encouraging utilisation of the pipeline in off-peak periods, making customers aware, in advance, of the transportation charge for a particular level and pattern of consumption, and ensuring that fixed costs are recouped through a fixed annual charge and that variable costs are recouped through a variable charge; and
- a systematic examination, by PASA and Sagasco, of asset values and depreciation policies to enhance financial performance. To improve project evaluation, PASA has developed specific guidelines consistent with those of the South Australian public sector.

Sagasco has pursued internal efficiency gains through improved management techniques, industrial relations and work practices by:

- identifying performance measures to evaluate management progress;

- reviewing work and management practices, involving both management and unions, to enable a simplified single award, a flatter organisational structure, multiskilled job descriptions, and improved training and development. . To strengthen employee commitment, an employee share option scheme, which was accepted by 94 per cent of employees, was introduced in 1989;
- increasing the use of contractors in many of its activities; and
- revamping appliance retailing operations.

4.6 Western Australia

The Western Australian Government and SECWA provided information on initiatives undertaken to improve the performance of the electricity and natural gas industries in that State.

Policy reviews

A Green Paper (Western Australian Government 1989) canvassed a number of energy policy options for the State and included:

- transferring the regulatory functions of SECWA to an independent regulatory authority;
- separating the electricity and gas supply functions of SECWA, to promote competition in the energy markets and remove cross-subsidies between gas and electricity; and
- breaking up the electricity component of SECWA into separate generation and transmission/distribution authorities.

Other options identified for increasing competition included, establishing competitive generating facilities (either completely dedicated to supply the grid or as peak supply sources), diversifying supply of natural gas to SECWA's pipeline distribution system, and terminating the policy of reserving energy resources for exclusive use by SECWA. The Government is considering the matters raised in the paper.

4.6.1 Electricity

Structural review and organisational measures

SECWA's recent review of its organisational structure and operations resulted in the adoption of a new structure aimed at ensuring a more business-like organisation. Particular account was taken of the need to reduce the centralised structure that had developed in the organisation. The new management structure is leaner and flatter, and has given managers a greater degree of responsibility and accountability for their own area of operations.

In consultation with the State Government, SECWA developed a Performance Agreement defining financial and operational performance objectives. The Agreement also outlines commitments on tariff increases, returns to Government, and reporting requirements for SECWA's performance. SECWA's Corporate Plan translates the objectives of the Performance Agreement into targets relating to the operations and responsibilities of its business units.

Other developments

Broadbanding of salaries for staff has been introduced to encourage greater productivity, efficiency and flexibility, and to reward increased productivity and work value; a performance management scheme supports this initiative. Also, the 11 existing awards were replaced with a single award to cover all salaried officers and a separate single award to cover all wages staff.

SECWA is also making greater use of contractors; generally in areas where the work load is variable. For example, contractors have been used to install gas pipelines and underground electricity cables in new residential areas, to construct transmission lines and, in some cases, maintain generation units.

Recently, the Western Australian Government announced (Media Statement 1991) that its next base-load power station will be a privately built, owned and operated coal-fired station at Collie, to begin operation in 1996.

Other initiatives directed at developing a more commercial approach to SECWA's operations include:

- tendering for the private construction and/or operation of a new base-load power station to ensure maximum cost-efficiency in the provision of additional capacity;
- negotiating with potential coal and/or gas producers for the supply of energy for new base-load power generation in a multi-fuel competitive environment;
- restructuring tariffs to reflect more closely supply costs;
- investigating cogeneration and buy-back schemes to improve resource utilisation;
- fostering competition between electricity and natural gas fuels; and
- increasing scrutiny of investment on capital works to improve the productivity of assets.

4.6.2 Gas

SECWA's monopoly over gas supply was removed in 1988. Companies finding commercial quantities of gas are now permitted to use it for their own purposes or to sell the gas freely, either to SECWA or any other organisation. These companies are also permitted to construct and operate private pipelines to allow the commercial marketing of gas.

While the announced changes were primarily aimed at stimulating oil and gas exploration, they could subject the gas activities of SECWA to potential competition from rival pipeline operators.

The Western Australian Government also indicated that it is considering a number of expressions of interest, from the private sector, for the acquisition of the Dampier to Perth gas pipeline.

4.7 Tasmania

4.7.1 Electricity

The Tasmanian Government stated that significant and wide-ranging measures have been introduced to improve the HECT's efficiency and reduce costs, and that further measures are in progress.

Commercialised operation

The State Authorities Financial Management Act (1990), effective 1 July 1990, was designed to ensure that all state agencies and authorities are made more accountable thereby improving operational efficiency and effectiveness. The Act requires: compliance with Australian Accounting Standards; enhanced reporting of financial and operational performance; strategic planning; guarantee fees; income taxation equivalent payments to the State; dividend payments; a real economic rate of return; and identification and costing of CSOs. The HEC Act is to be amended to allow these provisions to apply to the HECT.

To formalise the implementation process, a Commercialisation Advisory Committee was formed to advise the Minister on the degree of commercialisation of the HECT and the extent to which corporatisation should occur. A consultancy has also been completed which describes a master plan to place the HECT on a commercial footing. This process is expected to be completed by March 1992.

Initiatives which have already been undertaken to achieve a greater commercial orientation in the HECT's operations are:

- a corporate approach to planning;
- a commercial approach to financial management and performance;
- improvements aimed at reducing costs and the efficiency of operations;
- winding down of in-house design and construction activity;
- a stronger marketing orientation; and
- an increased emphasis on customer service;

Measures implemented to reflect this greater commercial orientation are outlined below.

Organisational changes

Changes in the operations of the HECT include: a reduction in the number of branches and management levels; a reduction of $1.5 million in the salary bill for managerial staff; a reduction in the number of employees - including construction employees (it is expected that over 8 years employment will fall by 48 per cent); the introduction of systematic management processes such as objective managing and performance management; and preparation to introduce a system of Total Quality Management.

Management techniques and performance targets

A consistent approach to cost control across the HECT is expected following the introduction of a new on-line Financial Management System in 1991. Commercial application systems will be upgraded and integrated financial information will be provided by linking a number of major information systems (eg customer information, human resource management, materials and motor transport management).

Performance targets have been adopted as part of the HECT's corporate planning process; a more comprehensive framework is being developed for performance monitoring. Expenditure reduction targets have also been introduced to facilitate a more effective budget-setting process.

Productivity and award restructuring

In 1990, 13 separate awards were replaced by a single award covering all employees. The HECT expects to achieve, with union support, significant productivity improvements by rationalising resource use, introducing more flexible working arrangements, increasing efficiency and enhancing employee skills.

The HECT is moving towards a wider use of contractors due to a reduced continuity in workload. Use of day-labour for the construction of power developments will be phased out and all other functions will be subject to critical review. Significant savings have been achieved by the contracting out of work associated with the distribution system.

Rationalisation of facilities

Infrastructure requirements will be reduced through a decrease in the number of control centres from nine to two. Also, the number of distribution districts in Northern Tasmania will be reduced, providing an expected annual saving of $1.2 million.

Studies are also examining the prospects for the automation of older power stations and the integration of operations and maintenance activities of the generation and transmission systems within geographic regions.

Consultant reviews

A recent review of electricity use in Tasmania (Department of Resources and Energy Tasmania 1990) recommended that the HECT adopt and announce a demand side management/energy efficiency policy. The report proposed that demand side management and energy efficiency options be officially endorsed by HECT management as reasonable alternatives to supply-side options, and that they be included in all future resource plans on a par with conventional alternatives.

A review of the HECT's energy costing and pricing policies, which identified issues for a more detailed second-stage review, was completed during 1990.

4.8 Northern Territory

Comments covering recent initiatives to improve the electricity and gas industries in the Northern Territory were received from the Northern Territory Government.

4.8.1 Electricity

Amalgamation of organisations

The major administrative change relating to electricity generation and distribution has been the establishment of PAWA in July 1987, when responsibility for the provision of water and sewerage services and water resources were added to the Northern Territory Electricity Commission's previous responsibility for electricity. This resulted in the sharing of overhead functions and a more commercial orientation to the provision of water and sewerage services.

Organisational measures

PAWA's Corporate Plan focuses on efficiency with the goal to break-even on commercial business. Strategic Plans have been prepared for each region and functional area, while other plans relate to marketing, infrastructure, environment, employees, information technology and public relations.

Management has been regionalised with responsibility for operational decision-making resting with the relevant managers. To provide the efficiency gains from amalgamation, particularly in remote areas, responsibility for the provision of electricity, water and sewerage services has been grouped together.

Program budgeting was introduced to all departments and authorities which receive substantial budgetary support from the Northern Territory Government. It is intended that all of PAWA's costs and revenues, including those directly affected by CSOs, will be highlighted in the budget process to make their contribution to the operational deficit clearly visible.

Performance targets have been established for each of the operating business components of PAWA and are being used as an internal management tool rather than for budget assessment.

Role of the private sector

Private sector involvement occurs through the provision of finance for infrastructure and the construction of a transmission line, power station and hybrid energy systems. PAWA's policy is to contract out the supply of services where it is more economic to do so. However, problems arise in some remote areas where there is a lack of appropriately qualified contractors.

Other developments

Since 1983, productivity has improved by 78 per cent and production costs, in real terms, have fallen by 20 per cent. These gains were attributed to:

- a 15 per cent reduction in employee numbers;
- a 50 per cent increase in power generation; and
- the conversion to natural gas which resulted in a 13 per cent improvement in energy conversion efficiencies, savings in fuel costs and the realisation of economies of scale.

Further savings are anticipated from the use of hybrid diesel-battery generating plants in remote communities, interconnection of remote communities (taking advantage of greater economies of scale), and the implementation of the Northern Territory Government's Energy Management Program to reduce energy wastage in Government buildings.

4.8.2 Gas

According to the Northern Territory Government, a number of changes have been made to improve the efficiency of the gas industry.

Currently, entry restrictions into the gas industry only apply where a reticulation franchise or licence has been granted. However, changes to the Northern Territory Pipelines Act will ensure that, in the future, licences will not provide any exclusive rights. Competition can also come from non-reticulated gas. It is expected that cheaper LPG, imported from Indonesia, will become available following the proposed deregulation of the LPG market in 1991.

4.9 Australian Capital Territory

Comments relating to recent initiatives to improve the electricity industry in the ACT were received from ACTEW.

4.9.1 Electricity

ACTEW is to be corporatised by 1 July 1991, following the recommendations of the ACT Priorities Review Board (1990) and the passing of the Territory Owned Corporations Bill. Initiatives undertaken to improve the performance of ACTEW include:

- introducing business units enabling objectives to be more clearly identified and the achievements of operational units to be evaluated;
- regionalising activities to bring staff closer to customers, thereby emphasising customer service and permitting performance comparisons and encouraging competition in achieving corporate goals;
- flattening the management structure and devolving responsibilities to lower levels in the organisation;
- agreeing with the unions to better work practices. However, flexibility and reform has been impeded by the 20 or more unions responsible for ACTEW staff. About 70 per cent of the workforce is already covered by enterprise awards and negotiations are under way to increase this proportion to 90 per cent.
- improving productivity - the customer-employee ratio has increased by 32 per cent; and
- using contracting and competitive tendering to raise efficiency.

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APPENDIX 5: COMMUNITY SERVICE OBLIGATIONS

Most public and private enterprises in the electricity and gas industries are required to undertake non-commercial activities. Largely because most are funded through cross-subsidies, they impose considerable economic costs. These costs often remain hidden. Some CSOs seem to be a legacy of past decisions which are no longer appropriate; others may have continuing relevance but could be provided in more cost effective ways. Many CSOs would be more appropriately funded by users. In cases where public funding of CSOs is used, cost transparency is essential.

5.1 What are CSOs?

Community service obligations (CSOs) are imposed by governments on utilities to satisfy a range of government policies and social goals of an essentially non-commercial nature.

This appendix outlines details of CSOs applying to electricity and gas utilities, including their method of funding, and examines the arguments presented in support of them. It considers whether other measures could achieve the same goals at reduced cost to the community. It also questions the success with which the equity objectives of some CSOs are achieved.

5.2 CSOs in the electricity and gas industries

The major CSOs administered by electricity and gas utilities relate to equity and development objectives established by state governments. Most are funded internally by the utilities, that is, by cross-subsidies. CSOs implemented by the electricity and gas industries include:

uniform tariffs	domestic concessions
pensioner rebates	obligation to supply
low income concessions	concessions to some large users
support for local mining	connection discounts
emergency assistance	tourist facilities
licensing payments	street lighting

More extensive information regarding these CSOs is provided in Appendix 3.

The stated objectives of many CSOs are unclear. CSOs are frequently confused with broader aspects of social policy, due in part to the indirect manner in which they are often communicated to enterprise management. A number of inquiry participants indicated that CSO requirements could be implicitly communicated, with consequent confusion as to governmental objectives. For example, SECWA stated that:

> ...on several occasions the government has made its views known to SECWA, and SECWA has taken those views into account, without the need for formal direction.

In addition, the costs of providing CSO services are often hidden and hard to quantify, due both to confusion about their nature and extent, and complexities associated with allocating costs between different activities where they are funded internally. The New South Wales Government observed that:

> Firstly, there are explicitly identified CSO's which involve transfer of monies ... The second kind of CSO's are the implicit CSO's that exist both as a consequence of tariff uniformity, and also as a consequence of the sub-economic operation of electricity generation plant which in turn is a consequence of coal sourcing policies. By the latter we mean that the generation system is not operated in such a way as the (potentially) lowest marginal cost plant is always the next plant brought into service.

5.3 The economic effects of alternative funding approaches

The effects of CSOs on the production and investment decisions of electricity and gas utilities and on the consumption decisions of consumers depend on the method of their funding. At present, funding mostly entails cross-subsidies. In some cases, direct subsidies are paid by governments to utilities to compensate for the costs of CSOs. Other mechanisms include setting lower rate of return targets to compensate for the costs of CSOs and levies on users. Each of these approaches to funding are considered below.

5.3.1 Cross-subsidies

Cross-subsidies involve excess charges (prices greater than the cost of supply) being paid by some users in order to subsidise other users of the same product (who face prices that are less than the cost of supply). In effect they are a consumption tax and consumption subsidy for different electricity and gas users. Cross-subsidies can arise either as a result of different prices being paid for the same product by different users, or from the application of uniform prices paid for a product regardless of differences in the cost of supply. In either case, the pricing system does not reflect the cost of supply to users.

Cross-subsidies result in allocative inefficiency. Those whose consumption is taxed restrict their usage of the product, even though they may value the consumption of additional units more than the cost of producing them. Consequently, there is a welfare loss. Conversely, those who are subsidised are encouraged to expand their use of the product beyond the point where the value they derive from the good is equal to its cost of production. Again, there is a welfare loss.

For industries which exhibit natural monopoly characteristics, it may be economically efficient to charge different classes of users different prices for the same product. An example of this is Ramsey pricing, which involves charging different users, or government users, different prices according to their price elasticity of demand. However, it does not involve charging any users less than marginal cost. Thus, all the economic costs of supply are recouped with minimal disruption to consumption patterns. In the case of electricity and gas, Ramsey pricing would imply charging higher prices to households, which exhibit relatively inelastic demand, and lower prices to other users. In practice, the opposite occurs. For example, domestic tariffs discriminate in favor of households at the expense of the business sector, and result in an inefficient mix of consumption between the two. As a result, domestic energy users consume electricity and gas at levels that do not reflect the opportunity cost of these resources to commercial and industrial users.

Resource use is also altered by the effect cross-subsidies have on using industries. Those firms which use subsidised electricity and gas more intensively gain an increase in competitiveness at the expense of other less intensive users. Those which use the higher priced electricity and gas more intensively are disadvantaged in their competition for resources with other firms.

Further resource use and consumption effects can result because of the necessity to combine cross-subsidisation with restrictions on competition. Enterprises engaged in cross-subsidies usually require protection so that other firms cannot provide cost-based service to market segments disadvantaged by the cross-subsidy. Given the characteristics of the electricity and gas industries, the removal of legislative barriers to entry may not give rise to competition in all sectors, but it would result in some increase in competitive pressure. In the absence of this competitive pressure, inefficiencies associated with monopoly can result, such as cost padding, high salary remuneration, restrictive work practices, overemployment and higher prices.

5.3.2 Direct Subsidies

Direct budget subsidisation of CSOs involves government funding from taxation revenue. In contrast to cross-subsidies, direct budget funding avoids the distortionary effects associated with incorrect pricing of services. Prices can be maintained at levels that reflect costs, so that efficient resource allocation results. This point was recognised by the 1989 Ministerial Working Party Report on Gas Regulation in New South Wales:

> From the point of view of economic efficiency, which relies on correct price signals to encourage a proper use of resources, a direct payment...not tied to the consumption of a good or product, is more appropriate than a discount against a purchase price.

Additionally, direct budget funding avoids the cost transparency/multiple objective problems characteristic of cross-subsidies:

- budgetary allocation is a good measure of the CSO's size because, with payments going directly to producers or consumers, there is a requirement for the amount of the subsidy to be expressed in money terms;
- annual budgetary review maintains a stronger discipline to ensure that CSOs are of continued relevance than when they are funded by uncosted cross-subsidies; and
- public enterprises can focus on their commercial objectives and, with the CSOs explicitly costed, it becomes easier to monitor their performance.

Direct budget funding can be implemented through two approaches: a producer subsidy paid to the electricity or gas enterprise for the relevant CSO, or a consumer subsidy paid directly to the consumer of the CSO service. Cost transparency problems are more likely to be associated with producer subsidies, since it may be difficult to reach agreement on the costs imposed on an enterprise by a requirement to provide a non-commercial service. Producer subsidies are also more likely to be associated with `in-kind' transfers , rather than being made through cash payments. In-kind transfers involve discounts on specific goods, such as electricity and gas.

Cash payments have generally been preferred over in-kind transfers in the literature because they place no restrictions on consumption choice. Because in-kind transfers restrict consumption choice, they are worth less to the recipients than an equivalent cash payment, which could be spent (or saved) according to individual choice. However, in-kind transfers may be used where there is concern that transfers would be `misused' by recipients, or where there is scope for people to claim transfers intended for others. In such cases, voucher systems may be introduced. Voucher systems avoid the efficiency effects of cross-subsidies and are compatible with competitive industry structure, since they allow consumers choice between alternative suppliers. Currently, voucher systems are used in the implementation of several small scale CSOs, such as the Electricity Accounts Payment Assistance Scheme, which is administered through community welfare agencies such as the Salvation Army in New South Wales.

Two main problems associated with direct budget subsidisation of CSOs were identified in submissions: their administrative cost and the possibility of inefficiencies arising from higher levels of taxation.

Administrative cost

Some participants argued that the administrative simplicity of cross-subsidies justified their use in preference to direct budget funding of CSOs. For instance the Northern Territory Government argued that:

> Administrative simplicity is also important in organisations where there are very few senior staff outside the main centres and where uniform pricing and billing procedures are the most efficient and reliable method.

In a similar vein, in its response to the Draft Report, the Latrobe Valley Community Forum commented:

> The concept of providing funds for community service obligations CSO's via other government departments almost guarantee ineffective targeting and slow program delivery to the detriment of the energy poor.

Cross-subsidy regimes require minimal administrative control since welfare transfers take place as part of the operation of the pricing system. In contrast, direct subsidies entail higher administrative costs. However, this possibility must be balanced against the wider efficiency gains of direct funding alluded to above. In the Commission's assessment, gains in these areas would outweigh any increase in administrative costs arising from direct funding.

Inefficiencies associated with taxation funding of CSOs

CSOs funded by cross-subsidies cause allocative distortions because of their narrow funding base and price effects. An advantage of relying on the tax system is its comparatively wider funding base.

However, the taxation system introduces price and income distortions of its own. Higher levels of taxation affect people's disposable incomes and/or the relative prices of goods. The size of the distortionary effect depends on the size of the tax impost and the price or income sensitivity of taxpayers. The form of tax influences the incidence of taxation on different income or consumer groups, and consequently their contribution to the provision of CSOs. If the CSO is funded by an increase in the general level of income tax, costs will be spread widely over all taxpayers. If the CSO is funded by a larger increase in the rate of tax on a particular good or service there will be a concentrated effect on the service's users. If the good or service were consumed by only a relatively small number of consumers, it could create greater distortions than cross-subsidy funding.

In Australia, the tax base available to the states is narrower than that available to the Federal Government. The Western Australian Government argued in its submission that many state taxes are more narrowly based than electricity and gas tariffs, so that it is less efficient for state governments to rely on state taxes to fund CSOs than cross-subsidies through electricity and gas tariffs.

While the Commission accepts that the States have a narrower tax base than the Commonwealth, this argument ignores several points:

- some State revenue sources are broader than the subset of electricity and gas users which currently fund most CSOs - for example, transport taxes and some franchise fees.

Moreover, such uniform taxes have smaller distortionary effects than cross-subsidies, because they don't create discrepancies in the price of the same product;

- barriers to entry required to support uniform pricing systems are detrimental to competition, and thus to efficiency, so that there are `hidden' resource losses that may exceed those of implementing a direct funding regime; and

- the public scrutiny accompanying direct budget funding of taxes implies that a more appropriately sized transfer could result under this approach.

5.3.3 Setting lower rates-of-return

In lieu of producer subsidies, governments can fund CSOs by accepting lower rates of return on their electricity and gas utilities' operations. This involves an implicit subsidy from the owners of the public enterprise (the community at large) to CSO recipients.

This approach shares the problems of cost transparency and accountability in common with funding by cross subsidy. For example, confusion may arise over the degree to which the required rate of return should be reduced to reflect the cost of financing CSOs, or to other factors.

5.3.4 Levies on users

Consumption levies on all users would make the cost of internally funded CSOs explicit. Under this approach, all users could have a line item printed on their bill covering the cost of providing each relevant CSO. Further:

- since the cost of providing the service is made explicit, the transparency problems encountered with cross-subsidy funding are overcome;

- barriers to competition are not required because all users can be levied regardless of their supply source; and

- reimbursement could be explicitly directed to the specific target group(s) rather than hidden by a system of indirect cross-subsidies.

These advantages are shared with the direct budget funding approach to CSOs. However, confining the funding base for levies to electricity and gas users may be less appropriate than broader funding bases, such as that utilised by direct budget funding.

5.4 The rationale for existing CSOs

CSOs applying to electricity and gas utilities have been in place for many years. Yet there appears to have been no systematic attempt to assess their continuing relevance, or whether they could be provided in a more cost effective way. This section briefly addresses both of these issues.

For the purpose of discussion, CSOs have been broadly categorised as equity or welfare related CSOs, industrial development CSOs and a third group of other smaller CSOs.

5.4.1 Equity or welfare related CSOs

Equity considerations appear to underlie several important CSOs, such as uniform pricing, domestic tariff concessions, connection subsidies and pensioner rebates, and other concessions to low-income or disadvantaged groups.

Equity relates to the desirability of alternative income distributions, and has two dimensions:

- *horizontal equity,* which pertains to the income distribution between individuals in similar circumstances;
- *vertical equity,* which pertains to the income distribution between people in different circumstances.

CSOs discharged by energy utilities and internally funded by cross-subsidies commonly mechanism used to pursue these objectives.. However, cross-subsidies are a blunt instrument for delivering desired equity results because they result in horizontal inequity. The incidence of the CSO is unrelated to the actual need of the recipient because electricity and gas consumption is incidental to welfare levels. Relatively high volume electricity and gas users are benefited to a greater extent than low volume users, such as those using alternative heating fuels (eg. Wood). Consequently, people in similar income circumstances are treated differently, that is, horizontal inequity results.

If it is judged desirable to maintain such CSOs, horizontal equity can be promoted more effectively by direct subsidies, because they can be paid to users on the basis of their circumstances. This point was noted by the New South Wales Ministerial Working Party Report on Gas Regulation:

> The principle that enables eligible pensioners to participate in soundly based welfare assistance programs which may be directed towards easing pensioner living costs has general community support. However, gas users should not be singled out to underwrite a welfare scheme which would more appropriately be part of the Government's overall welfare program.

In its response to the Draft Report, SAGASCO argued that if government continue to implement welfare programs through energy utilities they should identify and fund relevant CSOs:

> If low returns from any user group are a direct result of government direction, they are to all intents CSOs. For consistency with the proposed treatment of those obligations, the financial cost to the supplier should therefore be explicitly identified, and funds should be provided by government.

Concessional domestic tariffs

Concessional domestic tariffs transfer income from a small number of high volume, low cost, industrial and commercial energy users to numerous small volume, high cost, domestic users. Hence, this CSO is a cross-subsidy between tariff classes. As such, it is a vertical income transfer from ostensibly higher income business owners and shareholders to lower income domestic energy users. In its submission, the New South Wales Gas Users Group argued that, in New South Wales:

> The gas companies have been permitted to use their effective monopoly to transfer benefits from Sydney industrial gas consumers for other purposes, including the cross-subsidisation of other consumer classes and other regions. The lack of effective competitive pressure on the gas companies has also led to inefficiency in their operations.

This group estimates that the cost of this cross-subsidy to the total contract market is over $60 million per year.

It is hard to establish a clear rationale for this CSO, although several possibilities exist:

- the `essential good' rationale - but acceptance of this rationale implies that electricity and gas must be `more essential' for domestic users than commercial/industrial users;
- vertical income redistribution - acceptance of this rationale implies that all business owners and shareholders must be wealthier than all domestic users, which ignores horizontal disparities within each group;
- the political importance of the numerous domestic users.

Although the initial impost of concessional domestic tariffs is on business, and consequently has employment and output effects, the cost is ultimately passed onto consumers in the form of higher prices for the goods and services produced by affected businesses. Alternatively, the cost is absorbed in the form of lower profit margins, or lower production levels than would otherwise be the case. These outcomes have second round effects on employment levels and wages, as well as on profitability and remittances to shareholders. Hence, the effect of the subsidy in consumers favor is offset to varying degrees by the associated effects of the taxes imposed on the inputs of industry and commercial users. Moreover, as discussed above, concessional domestic tariffs lead to horizontal inequity through the `bluntness' of the cross-subsidies.

In view of the questionable rationales apparently underlying this CSO, its allocative costs and the uncertainty with which it promotes effective redistribution of income in any case, the Commission considers that it would be efficient to abandon this CSO.

Uniform tariffs and connection subsidies

These CSOs are associated with the obligation to supply all users at a `reasonable' price, and are undertaken by many electricity and gas utilities.

Uniform pricing effectively subsidises high cost regional electricity and gas users at the expense of low cost city users in the same tariff class. It also takes no account of the income levels of either contributors or recipients. Similar groups are taxed (positively or negatively) differently. For example, less well off (and wealthy) people in city areas are penalised while both wealthy and poor country electricity and gas users are left better off. Consequently, uniform pricing can result in vertical and horizontal inequity.

Internally funded connection subsidies have similar equity and efficiency effects. However, rather than being linked to ongoing consumption, connection subsidies relate to the cost of capital supply. The subsidy is capitalised into the value of the property, and represents a one-off windfall gain to the owner at the time of the CSO's introduction. This is realised upon sale. In effect, new owners pay for the value of the `subsidy' in the form of higher purchase price.

SECWA and the Northern Territory Government presented rationales for uniform pricing which typify the thinking behind this type of CSO:

> The justification of the uniform tariff policy is largely on the basis of perceived social equity issues and regional development advantages. The policy embodies the view that electricity is a necessity in modern society to which all citizens and industry should have access, regardless of geographic location.
>
> It would be inconceivable on equity grounds for the Territory Government to charge these users either the full cost of electricity...or alternatively the full cost less a "standard level of subsidy "... The Territory has a very low population, high cost structure, difficult climatic conditions, and suffers major disadvantages ... To increase the price of electricity in areas outside of Darwin would retard development.

Similarly, in its response to the Draft Report, the Tasmanian Government argued that:

> Policies of charging a uniform tariff to all users in each class regardless of location are of particular significance to Tasmania, where a higher proportion of the population lives outside major cities than for other States. While there are arguments that uniform tariffs may be sub-optimal from the electricity supply industry perspective, the promotion of regional development may provide some justification to require a uniform tariff policy.

These arguments suggest that the importance of electricity and gas in terms of equity is related to their status as `basic goods' or `essential services'.

The validity of this argument is questionable for two reasons.

First, it fails to account for the community's acceptance of market-based provision of other `basic' or `essential' goods such as food, housing and clothing, irrespective of the location of users.

These goods account for a larger proportion of the disposable incomes of households than electricity or gas. Second, when society judges it important on welfare grounds to provide a minimum acceptable standard of living, income supplements to disadvantaged groups are usually allocated through the general measures of the social security system. These are related directly to tests of individuals' income and/or asset levels. Society also provides a tax rebate for people living in some isolated or remote areas. Given the free choice of individuals to live in very remote areas, and accept the associated costs and benefits, there would appear to be no case on equity grounds to differentiate further between individuals.

If there is wide social acceptance of the need to subsidise the supply of electricity and gas, due to their basic good characteristics, these CSOs should be provided in the least distortionary manner. Ideally, this would be achieved through direct budget subsidies to CSO recipients. If, however, this was considered unacceptable for political or other reasons, a levy system, as described in section 5.3, would be preferable to a system of cross-subsidies, primarily because it would avoid adverse employment effects and the need for restrictions on competition.

Pensioner rebates and other welfare CSOs

Welfare CSOs attempt to achieve greater vertical equity by transferring income to groups within the community considered less well off. CSOs in this category include:

- pensioner and poor rebates;
- emergency health service rebates;
- rebates to single parents; and
- rebates to welfare agencies.

Pensioner rebates are funded by both direct subsidies and cross-subsidies. Others, such as emergency health rebates, are funded entirely through cross-subsidies. Cross-subsidy funding is undesirable for two reasons. First, it is a blunt instrument, as discussed above. Second, there is no case for the cost of these CSOs to be borne by electricity and gas users specifically. If these services are considered to benefit the whole community, they should be funded on this basis, through the taxation system.

It is questionable whether it is appropriate to use electricity and gas utilities to achieve the welfare goals of this category of CSO. The Federal Government administers a means tested social welfare program aimed at improving equity which could be expanded to undertake the responsibilities currently administered through this CSO. The administrative cost of running numerous poorly coordinated assistance programs through a variety of agencies, such as electricity and gas utilities, is likely to exceed that of operating a single centrally organised program which can be directed at dealing with the overall situation of particular individuals.

5.4.2 Industrial development

State government energy policies frequently attempt to bolster industrial development through concessional pricing to some industrial users. Lower connection rates and concessional energy prices are used to attract large industrial users. Such concessions are funded by cross-subsidies. These arrangements often follow discussion with state government development agencies, rather than with public utilities.

The rationale for this CSO appears to be that a stimulus to capital and energy intensive industries will lead to faster economic growth. However, the economic costs of this CSO makes it hard to justify. It distorts price incentives in a similar fashion to other cross-subsidies. Cheap energy for large industry is funded primarily from commercial and small industry users - which also bear the burden of cross-subsidies to residential users. Further, the true energy costs in each state are not reflected, so that the distribution of energy intensive industries between states may not reflect the economic cost of supply. Greater allocative efficiency would result if utilities charged industries at cost, and let location decisions reflect underlying cost differences.

A related CSO is local coal sourcing policies pursued by some State Governments. Such policies are hard to defend because they ignore the possibility of cheaper supply, and hence reduce allocative efficiency. Additionally, they encourage restrictive work practices and other forms of cost padding at the captive mines and lessen incentives for improving cost efficiency over time.

5.4.3 Other CSOs

A variety of other CSOs are required of electricity and gas authorities, including:

- regulatory CSOs, such as payment for the cost of licensing (SECV);
- street lighting;
- undergrounding overhead lines for aesthetic reasons;
- GFCV funding of the Community Energy Network;
- road safety subsidies in New South Wales; and
- the Energy Development Research Fund in New South Wales.

As a general principle the beneficiary group is the appropriate funding base for such CSOs. For this purpose these CSOs can be divided into three groups: those which benefit specific electricity and gas consumers; those which benefit other identifiable groups; and those that benefit the broader community. A few examples illustrate the thrust of this approach:

- *Road lighting* - this CSO benefits road users, not electricity users, and could therefore be more appropriately funded from road budgets;

Undergrounding of electricity cables for aesthetic purposes - the beneficiaries of this CSO are largely particular electricity users. These users should bear the cost of the CSO on user pays grounds, rather than impose costs on other electricity users in the form of higher and distorted prices. The value of the CSO will become capitalised into the value of the recipient's land; and

- *Funding of the Community Energy Network* (by GFCV) - this is a community pressure group directed at lowering gas costs to consumers. It should be funded by those consumers who directly benefit.

5.5 Summary

The arguments presented in support of most CSOs, such as electricity and gas being `basic' goods or important for `state development', have an apparent face value appeal. However, this Appendix has identified considerable efficiency and equity problems associated with their implementation. Additionally, the validity of funding these CSOs through other energy consumers has been questioned.

The plethora of unconnected CSOs serving different interests, implemented in isolation from each other and without consideration of wider efficiency and equity effects, lead to policy contradictions that tend to cancel out intended effects. For example, industrial to domestic cross-subsidies burden commercial and industrial users, yet special deals allow some large industrial users to pay less than cost for their electricity and gas.

Since contradictions are, in part the result of the ambiguity with which the objectives of CSOs are communicated. For example, the rationale for uniform pricing and connection subsidies seems to be a combination of regional development and equity goals.

Funding CSOs through internal cross-subsidies results in hidden costs, economic inefficiency, horizontal inequity and poor targeting of beneficiary groups. Comments from participants in the Draft Report hearings tended to regard these costs as incidental, instead focussing on the in-principle need to pursue CSO objectives. The Commission does not dispute the importance of these objectives, but rather seeks their implementation in the most efficient manner possible.

Consequently, the Commission considers that there is a need re-examine the rationales behind CSOs. This would help identify whether they have current policy relevance and, if so, the most efficient funding approach. Where a strong equity case is identified for the maintenance of particular CSOs, direct subsidies are the preferred funding method. Alternatively, levy systems can be introduced. Both of these funding methods have the advantage of being efficient, transparent and compatible with competitive market operation.

If electricity and gas utilities were freed of the need to implement CSOs, they would be able to focus on commercial objectives and the provision of electricity and gas in the most efficient manner possible.

APPENDIX 6: ELECTRICITY AND GAS INTERCONNECTIONS

At present there is little interstate trade in electricity or gas. This is due, in part, to political pressures which have resulted in, inter alia, the ESI being used as a means of supporting regional employment in each state/territory. Shortcomings in the administrative and financial arrangements of the Snowy Mountains Scheme have impaired the efficiency of the interconnected system. Government policies that have restricted the sale and use of natural gas have hindered the development of interstate gas connections. These policies jeopardise the economic development of new gas finds and future pipelines.

6.1 Introduction

In this appendix, interconnection, with respect to electricity, refers to the linking of otherwise independent electricity grids. It allows the transfer of power from one grid to another. Interconnection, with respect to gas, refers to transmission pipelines allowing the flow of gas across state or territory boundaries. This may or may not involve linkages with existing pipelines.

The discussion covers the benefits and costs of interconnections; existing interconnections; interconnections in other countries; future interconnections; and impediments to their use and extension.

6.2 Electricity

6.2.1 Benefits and costs of electricity interconnections

The major benefits of interstate electricity interconnections are:

Fuel cost savings

The size and type of generating capacity can vary significantly between grid systems. Consequently, at any given time, the marginal operating (mainly fuel) cost of plant in one system may be different from a neighboring system. If the two systems are interconnected, output from generators of low production cost in one can be increased while output from generators of higher production cost operating in the other can be reduced. This will benefit both systems, so long as the marginal production cost difference between the two systems is greater than the cost of transmission (including transmission losses) in transferring power from one system to the other.

Sharing of contingency reserve (spinning reserve)

Contingency reserve is plant required to supply power when unforeseen events result in either a sudden increase in load or a sudden outage of generating plant.

Power systems are generally operated with enough spare generator capacity on-line (spinning), or enough interruptible load, to cover the loss of the largest generator without significant effect on the system frequency or voltage; and with further, slower reserves available to be brought on line to replace within ten to fifteen minutes that reserve which has just been committed. This reserve capacity also covers differences between actual loads experienced and those expected when plant is being committed to service on an hour-by-hour basis.

When systems are interconnected it is possible to share this reserve, since simultaneous plant failures have a very low probability. New South Wales and Victoria each has sufficient interruptible load to cover any of these contingencies on its own system, but reserves are still coordinated. South Australia gained from interconnection as it had previously needed to keep plant on line as spinning reserve.

Sharing of reserve plant

All electricity systems require a reserve of plant in excess of that required to meet normal load peaks to cover occasional high peaks due to unseasonal weather conditions and to provide for unplanned plant outages.

When systems are interconnected, there is usually some diversity between loads and the pattern of plant outages. The diversity is generally greater when connected regions are in different time zones. Because the three mainland eastern states are in the same zone, the potential for sharing reserve plant is not as great as in Europe or in the United States of America. Nonetheless, the reserve plant for a combined system is proportionately less for the same level of reliability than it would be for the systems in isolation.

Rationalisation of resource use

The distribution of energy resources, economies of scale and industrial practices differ between states. In the longer term, the type and size of plant and transmission lines constructed in each state could be adjusted to be optimal for the interconnected system as a whole, even though the mix may not be optimal for each system viewed in isolation. This can lead to both capital and operating cost benefits.

Because of uncertainty about future demand, the timing of new investment is complex. The potential costs of uncertainty may be reduced if planning proceeds on the basis of a combined system rather than a number of smaller systems. The degree of certainty required to rationalise investment along these lines would normally require long term supply contracts.

The recent Memorandum of Understanding between Victoria and New South Wales is an example of this.

Encouraging greater competition

Provided viable extension possibilities exist, opening up electricity systems to alternative direct or potential supplies through interconnections would introduce a competitive element to the provision of electricity. In turn, this introduces an incentive to increase efficiency.

The major costs of interstate electricity interconnections are:

Capital and maintenance costs

The major direct costs of interconnection between state systems are the capital and maintenance costs of transmission lines and related voltage control devices, and costs associated with maintaining system stability. The latter costs include high speed protection relays and switchgear, stabilising equipment on generators and at substations, and associated harmonic control equipment. Interconnections may also require grid members to install compatible supplementary load-frequency control equipment. South Australia, for example, had to install new equipment as a condition of connection to Victoria and New South Wales.

Additional planning and operating costs

Interconnections incur additional management overheads in planning and operating and transaction costs of contracting, arranging and accounting for the interchange of power. Additional communications equipment is usually required for the interchange of information vital to maintaining the security of the interconnected networks and for trading in electricity.

Transmission losses

Energy is lost in transmission over interconnections (both real power and reactive power). This could be 10 per cent of the transmitted power for long distance interchange.

Instability and system disruption

Interconnecting systems increases the risk of instability and system disruption. A disturbance in one part of the system may result in a major breakdown in the entire interconnected system.

6.2.2 Existing electricity interconnections

At present, the grids of Victoria, New South Wales (including ACT) and South Australia are interconnected.

New South Wales and Victoria are linked at three locations. Foremost amongst these is the interconnection operating through the Snowy Mountains Scheme, which first operated in 1959. Lower capacity links are at Wagga-Albury-Wodonga, and at Mildura/Red Cliffs-Buronga/Broken Hill.

A link between Victoria and South Australia via Portland and Mt Gambier interconnects the systems of Victoria, South Australia and New South Wales. It is capable of transferring 500 MW from Victoria/New South Wales to South Australia and around 250 MW in the reverse direction. The link was completed on the 30 November 1989, and became fully operational on 1 March 1990. The most recent assessment by the SECV expects this link to save $39 million per year (in December 1990 dollars).

The present connections between New South Wales and Victoria allow the two state systems and the Snowy Mountains Scheme to operate as a single, integrated network on a day-to-day basis. The Snowy plays an important role in the transfer of energy between these States because it is linked to both systems and can provide peak and emergency supply. New South Wales and Victoria have had joint planning arrangements for operating the interconnected system since they were first interconnected via the Snowy Scheme in 1959.

The interconnection is used to exchange energy between the two systems in both directions, with the benefits of the transfers shared equally between the two states. The interconnection is also used to provide shared contingency reserve.

The Snowy Scheme operates under the umbrella of the Snowy Mountains Agreement, an Agreement between the Commonwealth, Victoria and New South Wales ratified by Commonwealth and State Acts of Parliament. This defines the entitlements of the States to Snowy electricity and water, and provides the basis for current institutional, financial and operational arrangements. The combined New South Wales and Victorian usage of Snowy power is forecast and planned by operating staff of the two Commissions and the Snowy operating staff in conjunction with State Water Authorities. The Scheme and its operations are discussed in Section 6.2.5.

Most interchanges have occurred on an `opportunity basis' to take advantage of generating cost differentials between the two states as they arise. However, New South Wales and Victoria have recently signed an agreement under which New South Wales will supply Victoria with a contracted volume of power - 1000 GWh per annum for the next several years. Opportunity interchanges will still continue between the two states.

The level of interchange between ECNSW and SECV for the past ten years is shown in Table 6.1. The larger flows from the SECV to ECNSW in recent years reflects the availability of power at low incremental cost from brown coal stations in Victoria during off-peak periods.

The interconnection between South Australia, New South Wales and Victoria operates under an Interconnection Operating Agreement, which governs the exchange of energy and provides for the equal sharing of profits between the two parties participating in an opportunity transaction and, where applicable, the payment of a transmitting (or 'wheeling') fee to Victoria. To assist in the most efficient use of the three state interconnection, a Joint Planning Committee (JPC) has been formed by the SECV, ECNSW and ETSA. This Committee, an expanded version of the two-state JPC which has operated since the introduction of the Snowy Scheme, considers interstate transfer possibilities and the scope for improved co-ordination of additional generating capacity.

Table 6.1: **Interstate electricity sales (GWh)**

Fiscal year	*To SECV from ECNSW*	*To ECNSW from SECV*
1980-81	625	93
1981-82	142	940[a]
1982-83	133	428[b]
1983-84	329[b]	127
1984-85	114	498
1985-86	7	518
1986-87	6	862
1987-88	58	1106
1988-89	79	598
1989-90	493[c]	632[d]

[a] Liddell winding failure
[b] Forced Snowy releases for irrigation
[c] Industrial problem in SECV
[d] Reduced export to ETSA allowing higher sales to ECNSW

Source: Information submitted by the New South Wales Government.

The Victoria-South Australia interconnection is presently used only for opportunity interchanges and reserve sharing, not for contracted transfers of energy. However, potential exists within the existing link for South Australia to receive contract energy transfers of up to the equivalent of 250 MW of annual generation. The South Australian Government is addressing this in its consideration of future supply-side options.

For that part of the 1989-90 financial year for which the link was available, the flow of opportunity interchange energy to ETSA from ECNSW and SECV is estimated at 310 GWh and 250 GWh respectively. At the draft report hearings, the ESAA stated that 25 per cent of South Australia's power needs were supplied by New South Wales and Victoria in the second half of 1990. The Government of South Australia's Green Paper on Energy (1991, p. 29) noted this interconnection will supply about 1500 GWh of electricity per year on an opportunity basis through the 1990s.

6.2.3 Electricity interconnections in other countries

Interconnections are common overseas, not only within countries, but between countries. They are most common in those parts of the world where there are high population densities, where major countries served are in different time zones and where there are significant differences in the size and/or type of generating plant in interconnected systems. In contrast, low population densities, the location of major east coast cities in the same time zone and some similarity in plant have limited opportunities for interconnections in Australia.

For many years the countries of Europe have gradually increased their interconnections and trading in electricity. Today, all these countries (except Ireland) are interconnected by either AC or DC links.

There are two major Western European networks for electricity interchange: Nordel and the Union for Coordinating the Production and Transmission of Electricity (UCPTE). Nordel links the systems of Norway, Finland, Sweden and Denmark. Iceland is also a member, but is not linked with the others. The UCPTE, which was formed in 1951, links most other Western European countries. UCPTE is a looser grouping than Nordel, but has been active in promoting joint construction projects for power stations, as well as interconnections. Interchanges and wheeling arrangements are coordinated through a central despatch centre at Laufenburg in Switzerland. UCPTE is the largest interconnected power pool in the world, servicing about 300 million people and covering an area of some 2.3 million square kilometres.

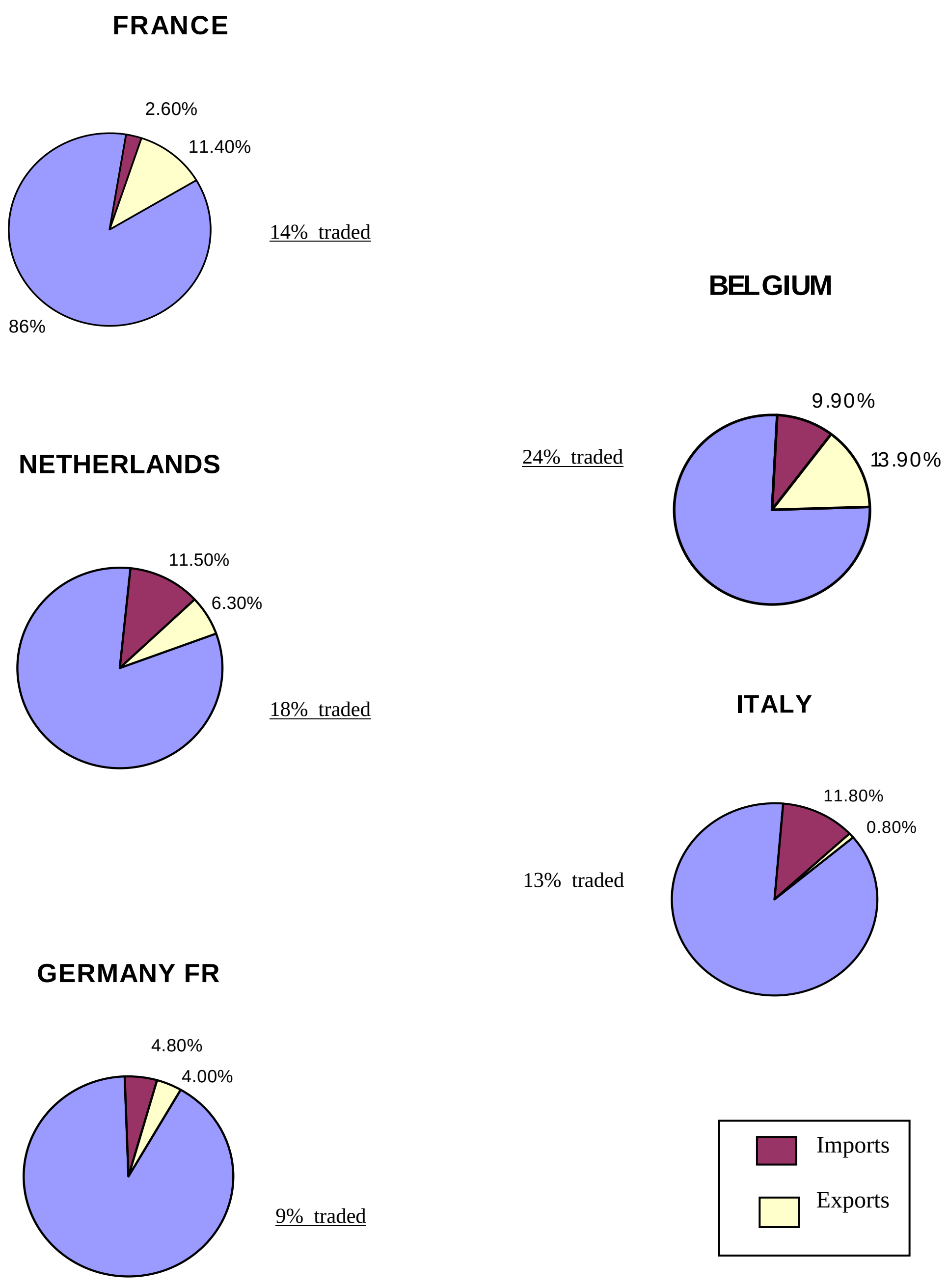
In the United Kingdom, the systems of England, Scotland and Wales are interconnected, and an undersea cable connects into the French system. The feasibility of doubling the capacity of the existing submarine cable is under examination.

Another major interconnected system covers the Eastern European countries.

Some European countries - such as France - have become substantial exporters, while others have become large importers. Italy, for example, imported around 12 per cent of its electricity requirements in 1987 (see Figure 6.1). Trade takes place on both an opportunity and contract basis. However, a recent working paper prepared by the Commission of the European Communities (1989, p.5) claimed that:

> ... net transfers, however, would be undeniably higher if the industry were free to take maximum economic advantage of them, irrespective of individual undertakings or internal interests.

Figure 6.1: **Traded electricity as a proportion of internal consumption, selected European countries, 1987**



Source: The Commission of the European Communities (1989)

The obstacles to greater trade include requirements imposed by member countries that local distribution undertakings and individual users buy from regional electricity utilities, and transmission and distribution monopolies which exist in each member country at national, regional and local levels. The working paper prepared by the Commission of the European Communities (1989, p.7) noted:

> ... they have nothing to gain from opening up access to their transmission and distribution grids to their rivals. Their sole reasons for purchasing electricity from other utilities are to balance their books or to cover temporary shortfalls in supply from their own generating capacity.

Attempts are currently being made to remove trade barriers to integrate further the electricity systems of EC countries. The EC has committed itself to the creation of a single market, with free circulation of goods, services, capital and people by the end of 1992. In this single market, competition shall be free of hindrance. The EC Commission intends to apply this single market concept, as far as possible, to electricity and gas. Its commitment in this area is indicated by legal proceedings against some Member States which maintain import and export monopolies for electricity and gas. The Commission's power in this respect was affirmed by a recent judgement by the European Court of Justice, which upheld Commission directives abolishing certain rights granted by Member States to companies in the telecommunications sector (Brittan 1990).

Some of the impetus for greater integration has come from recent studies which suggest that accumulated savings of up to ECU 55 billion - about $A90 billion - are possible between 1992 and the year 2010. They also suggest that more efficient utilisation of the grid would save one-third of the investment otherwise needed before the turn of the century.

In the United States, the ESI has extensive interconnections between grids, and has been characterised by increased coordination and cooperative activity. Formal power pools have been established with the right to despatch energy on an economic basis, as well as joint ownership of plants and transmission lines. Three separate power transmission networks together serve essentially all of the United States (except Hawaii and Alaska), as well as parts of Canada and Mexico (IEA 1985, p. 366). These are the Western Interconnection, the Texas Interconnection and the Eastern Interconnection.

6.2.4 Future interconnections

Any significant increase in interstate trade in electricity will require new investment to strengthen existing interconnections or construct new links. The possibilities are:

- increasing the capacity for interstate sales among New South Wales, Victoria and South Australia;
- linking the Queensland and New South Wales systems; and

- laying a cable under Bass Strait to link the Victorian and Tasmanian systems.

Given existing technology, it is not economic to connect the Western Australian and Northern Territory grids, either with each other or with the other states.

A 1989 report prepared for the IAC by Intelligent Energy Systems Pty Ltd suggested there would be significant benefits from having a more integrated eastern Australia grid. It forecast annual benefits of around $180 million from pursuing a strategy involving:

- a low capacity link of about 250 MW connecting New South Wales and Queensland. This could be justified before further peaking plant is installed in either system;

- a cable of 300 MW capacity to Tasmania, but only when all acceptable low cost dam sites have been developed;

- a block of gas turbines in Victoria. While this would probably not involve any strengthening of the New South Wales/Victoria link, the capacity of the Victoria/South Australia link could be increased to allow base load transfers, thus avoiding the establishment of expensive base load plant in South Australia; and

- as load grows in the interconnected system, the construction of additional base load plant, preferably in New South Wales or Queensland where, according to IES, the unit costs of base load plant are lowest.

At the draft report hearings, the ESAA and the SECV claimed the IEA study overstated the benefits. The SECV considered a more realistic assessment of potential long term net benefits of existing and new interconnections (in December 1990 dollars) would be $110 million per year. The SECV considered changes in industry structure are unlikely to have any significant effect on the achievement of these figures.

In its initial submission to this inquiry, the Tasmanian Government stated that while previous studies found the economic feasibility of cable interconnection was at best marginal, the power supply situation in each of the states is constantly changing. It noted that the cost of a cable interconnection has been declining in real terms due to improvements in technology. ASEA Brown Boveri Pty Ltd also referred to advances in relevant technology and noted that recent reviews have shown a decline in the costs of an undersea link between Tasmania and Victoria.

In April 1991, the Victorian and Tasmanian Governments announced the findings of a pre-feasibility study of a cable link under Bass Strait. The study (SECV-HEC 1991) concluded that such a link, which would have a capital cost of around $550 million and an annual operating cost of about $4.5 million, would provide economic benefits of $700 million or more for the two states. More detailed work is to be undertaken to substantiate these preliminary findings.

In its initial submission, the Queensland Government noted that a New South Wales/Queensland interconnection has been examined a number of times over the years. It stated that, at this stage, there appears little likelihood of such a link due to little or no time diversity in peak periods; relatively small differences in fuel costs; and the lengthy transmission lines needed to secure an interconnection. Nevertheless, QEC and ECNSW have initiated further investigations of the technical and economic feasibility of interconnecting the two systems. The Queensland Government said:

> There is no reason why an interconnection should not be established when or if it becomes economic.

In October 1990, the Special Premiers' Conference agreed to establish an Electricity Working Group to assess the feasibility of a jointly owned interstate electricity transmission system and consider options for further interconnection of the grids of all eastern states. The organisational options to be assessed include `a jointly owned interstate transmission system, a pool arrangement, and other ways of improving the management of current interstate arrangements'. This report of this working group is to be presented to the next Special Premiers' Conference in 1991.

6.2.5 Impediments to efficient use of existing and new interconnections

Potential impediments to the efficient use of interconnections and optimal investment in additional interconnections arise in the following areas:

- Planning/coordination;
- Snowy Mountains Scheme;
- Project/investment appraisal;
- States' reservation of energy sources; and
- State priorities.

Planning/coordination

Two recent inquiries (NREC 1988 and McDonnell 1986) concluded that interstate planning and coordination was inadequate and that, if the potential gains are to be realised fully, an improvement in consultation mechanisms was required. The NREC referred to the New South Wales/Victoria Joint Planning Committee as a step in the right direction. However, it expressed doubts about the adequacy of this body for ensuring a sufficient review of interconnection possibilities. It considered it fundamentally a technical body not suited to resolving broader issues.

In its initial submission, the SECV acknowledged past difficulties with planning between states. It considered they would be substantially overcome with the proposed ESAA Strategic Planning Council and a Joint Planning Council of Chief Executives of the Authorities in New South Wales, Victoria and South Australia.

The SECV stated the joint planning arrangements would provide:

> ... an efficient and practical alternative to the creation of a Federally managed planning body.

The New South Wales Government noted that the three electricity authorities have been examining their future system operation in a number of forums under the overall aegis of an Interconnection Management Committee. These forums include Joint Planning, Operating and Engineering Committees which resolve planning, operational and technical matters.

To fully realise the potential gains from interconnections, the Commission's draft report (and this report also) proposed that one body operate all transmission assets in New South Wales, Victoria, Queensland, South Australia and Tasmania. Each electricity utility that commented on the proposal favored retaining the present ownership of transmission assets, and each proposed a virtually identical view on how best to manage the planning and coordination of an interconnected system. The Tasmanian Government considered:

> The preferred arrangement for the co-ordination of transmission arrangements would be the formation of a co-operative Council rather than the creation of a national authority to acquire the transmission assets of authorities. ... Initially it would formalise and extend the present informal arrangements in planning and operating the NSW/VIC/SA interconnected system. Private generators, distribution entities and/or major customers could also become involved as changed structural arrangements within the industry emerge.

The ESAA and the SECV proposed the Nordel model as the most appropriate base for managing an interconnected grid. They noted the industry is rapidly pursuing this option. The SECV stated it is proceeding in cooperation with New South Wales and South Australia to establish a National Grid Management Council (which would include Queensland and Tasmania). This, it believes, will best manage the necessary coordinated planning and operation of generation and transmission systems. It proposed that the Council be directly managed by the state grid utilities that are interconnected or are likely to be interconnected, without the need for directives or control by any superior body.

As discussed in Chapter 7, the Commission does not consider these arrangements - which are not dissimilar to the current management of the three-state interconnected grid - will result in the most efficient operation and development of an integrated `National' grid.

The NREC inquiry also identified the lack of a sufficiently well developed model simulating the three-state interconnected system as a barrier to effective interstate planning and coordination. The New South Wales Government said the three states have cooperated in the development and application of computer models of their electricity supply systems.

This has extended the Monte Carlo computer model used in planning in New South Wales and Victoria to include South Australia and Queensland. The development of modeling capacity will facilitate effective interstate planning and coordination.

Snowy Mountains Scheme

There is some contention whether the most efficient use is being made of the Snowy and transfers of power from it via interconnections. This contention revolves around, first, the efficiency of the institutional arrangements governing its operation and, second, the pricing arrangements for Snowy outputs.

- **Institutional arrangements**

Two public bodies, the Snowy Mountains Hydro-Electric Authority (SMHEA) and the Snowy Mountains Council (SMC) are involved in the operations of the Scheme. SMHEA is a Commonwealth Government business enterprise established under the Snowy Mountains Hydro-Electric Power Act of 1949. SMC is an unincorporated body which represents the interests of all parties to the agreement - the Commonwealth, New South Wales and Victorian Governments.

Previous reports have alluded to difficulties in defining the respective responsibilities of the two bodies. For example, McKinsey (1986, p.2) stated:

> The division of responsibilities between these two bodies for important aspects of management of the Scheme is exceedingly complex and, in practice, unclear. The lack of clear lines of responsibility at the highest level of decision making has created the greatest possible constraint to the development of effective, efficient, and accountable management of the Scheme.

The report noted that neither the SMHEA nor the SMC has the responsibility, power or capacity to develop plans and procedures for the effective operation of the Scheme.

Submissions to this inquiry confirm difficulties in this area. SMHEA stated that:

> ... a lack of clarity regarding the respective responsibilities of the SMC and SMHEA is the most significant impediment to the efficient management of the Scheme.

On the other hand, the SMC stated the Authority's and Council's responsibilities in this area are defined in the Act and Agreement. It said that:

> Responsibility for the control and direction of the operation and maintenance of the Scheme is vested in the Snowy Mountains Council.

The SECV and the Victorian Rural Water Commission claimed that the lack of clarity on respective responsibilities is a product of the Authority's own making. They stated that the respective responsibilities of the SMC and the SMHEA are currently being addressed by Council.

The institutional arrangements are also being examined in a joint review by New South Wales, Victoria and the Commonwealth established by the Prime Minister.

It is important that a large asset which plays a most important role in the south-east Australian electricity grid functions efficiently. The lack of clarity associated with the present arrangements must reduce accountability and the incentives for efficient management. There is a clear need to consider the available options to overcome the present difficulties. If possible, management responsibility should be vested in the one body whose primary purpose would be to manage the scheme to maximise the benefits - from a national rather than a state perspective. In information submitted in response to the draft report, both SMC and SMHEA agreed that a single management body would increase efficiency within the Scheme.

- **Pricing arrangements**

Water released by the Scheme for irrigation is at present free to users. Under the Agreement, all costs are recovered from electricity sales and the price of electricity is based on its costs of production. However, these costs are significantly understated. The SMC noted that, while all depreciation charges are brought to account in the net cost of production, the manner and rate of depreciation is not consistent with current accounting conventions. Under the Agreement, depreciation charges are based on historic rather than current valuation. No return on the original Commonwealth investment in the Scheme is appropriated by the Commonwealth as the Scheme is not required to pay a rate of return on Commonwealth funds invested.

The SECV and the Victorian Rural Water Commission stated that the rules for the pricing of the Scheme's outputs and its operation were agreed on at the time the Scheme was established. Accordingly, they argued against any changes in the pricing arrangements. They also argued against valuing assets at current cost for depreciation. They considered it inappropriate that charges for prospective, rather than actual, asset replacement and refurbishment are added to the cost of production, and thus generate funds internally prior to the need for, and clear definition of, the work required.

The present arrangements are contrary to conventional commercial practice. They mean that assessed capital and operating costs are met by electricity users, who are therefore subsidising water users. However, to the extent that an economic return on funds is not achieved, electricity users (or the authority purchasing the output) are also subsidised. Moreover, even the full economic costs of SMHEA electricity probably understate the opportunity costs. Thus, there is a risk that the SMHEA investment is not utilised efficiently and that benefits from expansions to the Scheme are undervalued.

As a result of these arrangements, water is 'underpriced'. The net effect on the price of electricity is not clear, although the price almost certainly does not reflect true economic costs. Thus, users face inappropriate prices for both water and electricity from the Scheme. This can distort usage patterns and create the potential for inefficient investment decisions.

However, to the extent that the value of Snowy water and power is, as stated by the SMC, explicitly considered for planning and operational purposes through the use of `shadow pricing', the potential for inappropriate investment decisions is reduced.

A further issue with the pricing of Snowy power is whether it should be priced at its economic value. The economic value of Snowy power, used as it is for peak and emergency use, is considerably higher than the financial price charged, even if production costs are based on current asset values. The pricing of Snowy power to ACT illustrates this issue. ACTEW stated that its entitlement to Snowy power is credited to the amount it owes ECNSW for electricity at production cost plus a wheeling fee. However, Snowy power is usually only generated to meet system peaks, at which time its economic value is high - very much higher than the amount credited to ACTEW by ECNSW. Thus, in effect, ECNSW appropriates a significant proportion of the benefits of low cost Snowy power which should accrue to the ACT. ACTEW estimated that this practice costs it about $25 million annually.

If Snowy power prices reflected the opportunity cost of alternative supply, the potential for inappropriate consumption decisions would be avoided and the problem associated with the pricing of power to the ACT would be overcome. If this is not possible, there would seem little reason why the present arrangements between ACTEW and ECNSW should continue.

Investment appraisal/evaluation

Participants suggested that new investment in interconnections would occur when they could be economically justified. For example, the ESAA stated:

> The development of new interconnections (eg between Victoria and Tasmania or between New South Wales and Queensland) or the strengthening of existing connections, will take place when commercially viable.

However, shortcomings in the appraisal/evaluation of different investment options and inconsistencies between states have the potential to restrict the optimal use of interconnections.

Evaluation/appraisal outcomes are sensitive to the methodology employed. In particular, results are affected by the approach taken on valuation of assets, rates of return and the tax treatment (especially for comparison of public/private options).

Submissions provided evidence of state initiatives to improve the basis of investment evaluation. For example, ECNSW has adopted new capital investment appraisal guidelines, while the South Australian public sector has also made a significant effort to improve project evaluation in the last 18 months. with its development of guidelines for project evaluation, workshops to raise the general skill level of project managers in evaluation techniques and the development of a project evaluation advisory role in the SA Treasury to assist agencies in the evaluation of projects. However, while there have been improvements in some areas, there are still wide variations in accounting standards, the extent to which authorities are liable for taxes and other government charges and rate of return requirements (see Appendix 3).

This militates against the efficient evaluation of the scope for further interstate sales and new investment in interconnections.

Project evaluation in the Snowy was the subject of conflicting views. The SMHEA stated that there is no mechanism for optimising the investment opportunities in the three state power system. The SECV refuted this. It claimed there is such a mechanism, although the SMHEA does not have a role in it. According to the SECV and the SMC, the Strategic Maintenance Review Group (SMRG) ensures investment in the Snowy is subject to the same rigorous economic appraisal mechanisms as are applied in New South Wales and Victoria. In response to this claim, the SMHEA stated:

> While this process should, in principle, optimise the Authority investment level within the interconnected system, this is not so in practice. ... To date, however, such analysis [by the SMRG] has been confined to plant refurbishment and upgrading options within the Scheme and has not included consideration of possible future development options such as pumped storage.

One operational problem associated with assessing the merit of interconnection transfers arises from the current approach to allocating the gains from such interchanges. While the capital costs of transmission lines and connections are allocated pro rata on the basis of benefits accruing, the actual cost-savings are shared equally. From a national point of view this can lead to a sub-optimal use of interconnections and distort the incentives for additional links. The New South Wales Government noted that, under these arrangements, the flow of electricity will be directed to those opportunities giving maximum profit to the seller rather than to the system overall. It gave as an example pumping for storage versus sale to another state. If pumping for storage would return the SECV $7.50/MWh compared to an equal share of an overall saving of $10/MWh if the electricity was sold to ETSA (ie $5/MWh each), then pumping would be the SECV choice. A more flexible approach - such as the negotiation of selling prices between the two parties concerned - would more closely resemble normal market transactions and would overcome such perverse outcomes.

States' reservation of energy supplies

A number of participants referred to the policy of state governments reserving gas for use within their state and specifying end-use restrictions. The most notable impact of this policy on the use of interconnections is the Victorian case (see Section 6.3.3).

Policies that restrict access to gas will affect the nature and locations of new power stations. In turn, this will impair the efficient development of an integrated electricity grid in south-eastern Australia. For example, the study undertaken by IES identified considerable benefits over the next 15 years from the installation of gas-fired turbines in Victoria to meet New South Wales peaking and standby plant needs.

State priorities

State governments have often seen electricity authorities as a means of supporting regional employment, not only in power stations but in associated mines, repair shops etc. In turn, pressures have been exerted on some governments (eg South Australia and Tasmania) to ensure that electricity continues to be sourced within the state (see Rosenthal and Russ 1988). In its initial submission to this inquiry, the New South Wales Government acknowledged that political interests had in the past sometimes discouraged interconnections and interstate sales.

While there may be benefits in the form of increased employment in the state's own ESI as a result of decisions not to purchase lower cost power from other authorities, account also needs to be taken of the consequences of higher production costs. These are passed on to the community by way of higher than necessary electricity charges or reduced returns from electricity authorities. In both cases, economic well-being is reduced for the national economy, and possibly for the state's own economy.

Submissions by electricity authorities and governments appear to recognise these costs. They also imply a greater willingness to evaluate all power options, including the scope for further interconnections. However, if the potential benefits of increased interconnections are to be realised, such attitudes will need to be translated into positive co-operative actions.

6.3. Gas

6.3.1 Existing gas interconnections

The only major interstate pipeline interconnection at present is that owned and operated by The Pipeline Authority (TPA), a Commonwealth Government statutory authority[1]. It links the South Australian Moomba field with New South Wales and the ACT. Virtually all other domestic trade in gas is intrastate.

AGL is at present the only user of the TPA pipeline. AGL purchases gas from the Moomba joint ventures. AGL retains ownership of gas sold into New South Wales and TPA charges haulage for transmission through its pipeline. Gas destined for sale in the ACT is sold by AGL to the TPA at Moomba, and is subsequently resold to AGL Canberra at the city-gate.

Overseas, interconnections between states and often between countries are common. For example, in North America there is an extensive pipeline network linking the United States, Mexico and Canada. About a half of the United States' natural gas resources are located in the Gulf Coast area. Around a half of the gas produced in this region is sold into interstate markets.

[1] The GFCV owns and operates a pipeline to Albury, in New South Wales.

Substantial exports of gas also occur between the USSR and Western Europe. In the European Community, around a half of the gas consumed is imported from other Member States or from other countries.

6.3.2 Potential gas interconnections

Gas is a natural form of energy and does not have to undergo a highly capital intensive process equivalent to electricity generation. Consequently, the range of benefits through interconnection are more restricted than is the case with electricity. Nonetheless, major benefits that may stem from further interconnections in Australia are, first, economies which would result from a more efficient depletion of eastern Australian gas resources (which would also improve the viability of a Trans-national pipeline), second, the increased availability of gas in some markets and, third, benefits to users as a consequence of their being able to negotiate with more than one gas producer.

The major costs associated with pipeline interconnections are the capital and maintenance costs of pipelines and compressors, and the sophisticated control systems required to move the gas around the network.

Although new gas discoveries are still being made in eastern Australia, participants expect that supply will have to be augmented by additional gas from north-west Australia sometime in first two decades of the next century. For example, TPA stated:

> It is evident that in the longer term most States will be dependent upon gas from the offshore north-west. Western Australia will continue to be self-sufficient in gas in the longer term and the Northern Territory may be also. Queensland has sufficient reserves within its borders to satisfy medium term requirements, but will require a long pipeline to the south-west of the State in the foreseeable future to satisfy existing and new markets. South Australia and New South Wales are likely to secure at least some of their gas supply from a new source within a few years. Victoria has sufficient gas within its own territory to satisfy demand for perhaps twenty to thirty years but will then become dependent upon higher cost interstate gas.

The AGA has undertaken a major study of possible future pipelines. Only one transcontinental pipeline was considered, starting at Dampier and terminating at Moomba. Under this scenario, Moomba would become the staging point for supplies to the southern and eastern States. The Western Australian market would be supplied with gas via a transmission network that is expected to remain independent of that supplying other States. Pipelines would run from the North West Shelf to the Northern Territory and South Australia and link with others to supply the eastern states. The study did not envisage that Tasmania would be interconnected.

Possible pipeline developments identified by TPA, including the Dampier-Moomba link, are shown in Table 6.2 below.

Table 6.2 : Possible pipeline developments

Route	Indicative Quantity	Length	Possible Diameter	Indicative Cost
	(PJ/Year)	(km)	(mm)	($m)
SW Qld to Moomba	30	220	357	55
Amadeus Basin to Moomba	30	900	457	300
SW Qld to Wallumbilla	50	770	508	290
Albury to Wagga Wagga	25	130	324	50[a]
Longford to Goulburn	60	530	508	225
Wollert to Young	240	540	762	500[a]
Wollert to Adelaide	100	710	508	370[a]
Dampier to Moomba	800	2 500	1 321	6 000[a]
Wyndham to Moomba	800	2 000	1 321	5 000[a]

[a] Includes compression
Source: Submitted by TPA

6.3.3 Impediments to the efficient use of pipeline interconnections

Private enterprises with gas interests clearly consider that governments represent the most significant impediment to further interconnections. For example, Esso argued that government involvement distorts market forces and produces sub-optimal outcomes.

State policies restricting the interstate transfer of gas help explain the current limited gas interconnections. In South Australia, for example, the South Australia Natural Gas (Interim Supply) Act 1985 limits any further supply of gas from South Australia to New South Wales above existing contracts, unless specifically authorised by the South Australian Minister. The Northern Territory Government has recently refused to agree to the `export' of gas from the Amadeus Basin to South Australia. The Victorian Government has a policy restricting the use of gas in electricity generation within that state to an additional 500 MW. The policy does not permit new gas-fired base load plant. The Victorian Government does not accept that this policy of restricting gas-fired generation is unduly restrictive. However, other participants (eg APEA Ltd, AGA, North West Shelf Domestic Gas Joint Venture Participants) considered the unrestricted use of gas for power generation fundamental to the development of interstate pipeline interconnections.

In those cases where governments have agreed to permit interstate sales of gas, certain conditions have applied. For example, in agreeing to sales from south-west Queensland to South Australia, the Queensland Government required that, first, the condensate be processed within the State and transported to Brisbane (Wilkinson 1990, p. 24) and, second, that the price be no lower than that applying to gas for use in Queensland.

Similarly, Shell noted South Australia has prevented the inclusion of ethane in gas deliveries from Cooper Basin and considered this a barrier to interstate trade. According to the Government of South Australia's Green Paper on Energy (1991, p. 25):

> The rationale behind this requirement is to preserve ethane as a feedstock for a *possible* [emphasis added] petrochemical plant which might be located in South Australia.

In some states, there are exclusive transmission franchises. For example, in South Australia, legislation vests transmission rights in the PASA. This form of legislation clearly precludes potential new pipeline owners and consequently inhibits interconnections. It also limits the extent to which producers can negotiate directly with users.

Legislation governing the design, construction and operation of pipelines which varies markedly between states/territories is also said to be cumbersome and to deter new pipeline construction. The Australian Pipeline Industry Association, for example, stated that legislation in all states has inherent problems and pointed to a need for greater co-ordination.

A number of participants expressed concern that governments could interfere and jeopardise future interconnections. They expressed the view that market forces and private sector interests would assure the appropriate outcome. For example, AGL stated:

> We believe that the reserves in eastern Australia should be depleted so as to achieve a simultaneous need for the reserves from the north-west to be drawn on via a Trans-national pipeline to supply Queensland, NSW, Victoria, SA and the Northern Territory. This process should be initiated by the players in the market, and co-ordinated by a national body such as the AGA.

On the other hand, the New South Wales Government considers that access to future gas supplies is a responsibility of government, as well as the private sector. It stated that:

> The Government is committed to playing a positive and constructive role and to liaising with the private gas industry as well as other state governments and commercial interests.

The Queensland Government expressed a similar view. It considered that:

> ... the State Government has a responsibility to ensure a sufficient supply of gas for existing consumers. This, together with assessments of the likelihood and timing of future extensions to the inter-State pipeline network, provides a rationale for restrictions on exports of a limited resource. Co-ordination between States, e.g. through the AMEC Working Party on Regulation of Interstate Gas Pipelines and joint planning could remove the basis for concerns about State resource monopolisation.

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APPENDIX 7: COGENERATION

Cogeneration provides an opportunity to utilise heat that would otherwise be wasted. It provides an alternative source of supply to augment that from electricity utilities. It could also allow utilities to defer new investment. Factors which appear to have constrained the use of cogeneration to date include, first, the lack of information available to industry about its application and the terms on which electricity produced by cogeneration will be purchased by electricity utilities and, second, some reluctance on the part of utilities to accept that electricity produced by cogenerators could be to their advantage.

7.1 Introduction

When heat for industrial, commercial or residential uses can be produced jointly with electricity (cogeneration) rather than separately, there is scope for significant gains in the thermodynamic efficiency of energy use. However, thermodynamic efficiency is only one aspect of cogeneration. For an enterprise to invest in it, or for the community to benefit from cogeneration, it also needs to be justified on economic grounds.

This appendix briefly describes what cogeneration is, and considers a range of factors relating to its future development.

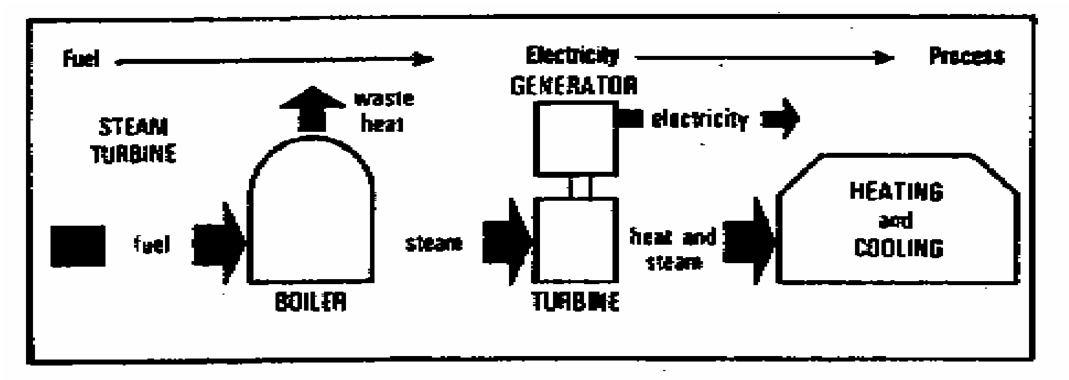
7.2 What is cogeneration?

Cogeneration is the combined generation of electricity and other energy, such as mechanical power and/or process heat, from the same fuel source. It makes use of heat which would otherwise be wasted.

Cogeneration has been used since the earliest industrial applications of electricity. For many years after the invention of the electric motor and generator, electricity for industry was produced as a by-product of the mechanical energy and heat produced by steam engines and other sources. The development of central large-scale power stations and relatively cheap electricity resulted in most industries opting to purchase their electricity requirements rather than generating it themselves.

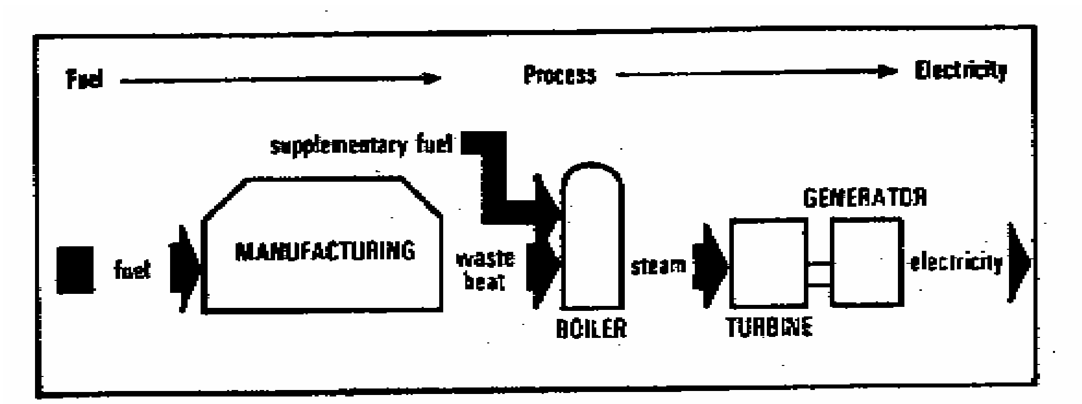
There are two general types of cogeneration - topping and bottoming systems. A topping system first applies steam produced from a boiler to generate electricity, and then uses the discharged steam as a heat source for production processes (see Figure 7.1). An important variant of topping is where a gas turbine is used to drive a generator to produce electricity, and heat discharged from the turbine enters a waste heat exchange to produce heat or steam needed in the production process. This system is used in the pulp and paper, food and chemical industries. A bottoming system uses recovered waste heat after it has passed through the production process, often with the addition of more fuel, to generate electricity (see Figure 7.2). This is generally used where an industry produces waste heat at high temperatures, such as the glass, metals and cement industries.

Figure 7.1: **Topping cycle cogeneration**



Source: Office of Energy Planning, Energy News for Industry and the Community, May 1990, p. 2.

Figure 7.2: **Bottoming cycle cogeneration**



Source: Office of Energy Planning, Energy News for Industry and the Community, May 1990, p. 2.

Typically, most of the energy generated by cogeneration facilities is used on-site by industry for its own purposes. However, it is not unusual for a cogenerator to be in a position to sell surplus capacity. Alternatively electricity may be needed from the grid, as it is difficult to match the two parts of a cogeneration installation.

Although cogeneration installations lack the scale economies of central power stations, their thermodynamic efficiency is greater - as high as 80-90 per cent compared to a maximum of around 35-40 per cent for a conventional coal-fired power station. Cogeneration installations also tend to achieve much higher availability factors than conventional power stations. Greene (1989, p. 7) claims this may be of the order of 98-100 per cent.

While older cogeneration facilities used steam boilers and turbines in the energy conversion process, more efficient modern equipment comprises natural gas powered turbines and diesel engines fitted with devices to recover waste heat energy. Cogeneration equipment is now available in capacities ranging from tens of kilowatts to many megawatts.

In cold climates, where a power station is located in a city or town, it is common to discharge the heat from a conventional power station at slightly higher than usual temperatures, and circulate the steam as residential 'district heating'. This is very common in Northern European countries and in the US and Canada.

7.3 The economics of cogeneration

Joskow and Jones (1981) and Joskow (1982) provide criteria determining whether it is economic for a firm to invest in cogeneration. Four areas are identified:

- The difference between the capital costs of a cogeneration system and the capital costs of the conventional heat-generating system the firm would use if it does not cogenerate.

- The difference between the cost of fuel and operating expenses required by a cogenerator and the cost of fuel and operating expenses which would be incurred if the firm does not generate.

- The heat load characteristics of the firm (eg size of peak steam load and load duration) which affect the amount of electricity produced. Scale economies are important for cogeneration. For example, as the size of process heat demand or load duration decreases, incremental cogeneration costs increase with smaller scale operation.

- The value of the electricity produced. This may be either the value arising from the replacement of electricity purchases, from the sale of surplus electricity, or from both.

> The economic viability of cogeneration is extremely sensitive to the price of electricity bought and/or sold.

Market and institutional impediments to the appropriate development of economic cogeneration are dealt with in Section 7.6.

7.4 Existing cogeneration in Australia

Cogeneration has recently been promoted in Victoria (by SECV and DITR) and South Australia (by ETSA, Sagasco and the South Australian Government). Both States have investigated the likely benefits of cogeneration and have taken steps to encourage investment in cogeneration facilities from likely industrial customers. This climate of interest and encouragement is reflected in the fact that detailed data on cogeneration are only available in these two States. Available cogeneration capacity represents a little less than 3 per cent of each State's total electricity generating capacity.

In its submission in response to the draft report, the Government of Tasmania stated that existing cogeneration in Tasmania is less than one per cent of installed capacity. In part, this reflects natural gas not being available in Tasmania. However, it noted that:

> The Hydro-Electric Commission is developing policy measures aimed at actively pursuing the cogeneration potential of industry identified as economically viable.

In Western Australia, SECWA has indicated support for cogeneration, but is not actively encouraging interested parties. The Report of the Review Committee on Power Options for Western Australia was more positive (1990, p. 59), recommending:

> SECWA should encourage cogeneration projects and should adopt and advertise this policy.

Broadly speaking there is a consistent pattern in the types of industries which are involved in cogeneration. They comprise industries requiring large quantities of process energy (eg petrochemicals, pulp and paper), and cover a wide range of manufacturing activities. There is a trend to applying cogeneration in areas other than manufacturing. For example, cogeneration facilities are installed in two hospitals, a bank and a recreation centre in South Australia.

7.5 Cogeneration potential in Australia

There is limited information about cogeneration potential in Australia. However, studies have been published on cogeneration potential in three states; New South Wales (Greene 1989), Victoria (DITR 1990) and South Australia (SAEC 1985). These references form the basis of the following outline. Limited information is available on cogeneration in other states/territories.

New South Wales

The New South Wales study found most cogeneration facilities have been in place for a number of years, and that few new facilities have been developed because they were economically unattractive (Greene 1989, pp. i-ii):

> The Electricity Commission of NSW has not encouraged industries to install cogeneration. At present, with a surplus of generating capacity from existing power stations and another station nearly completed, the Commission has no need for additional generating capacity. Its programs and tariffs, therefore, offer little incentive to industries contemplating cogeneration. ...
>
> Nearly 1000 MW of cogeneration would be developed by 1996 in NSW if current economic and institutional barriers were removed. The untapped potential currently existing in industries requiring process heat is over 1800 MW. Additional potential exists in other types of industries and in facilities that have access to a waste product or material that could be used for fuel. The barriers that exist are significant.

The potential for about 1000 MW of cogeneration capacity by 1996 is around 7 per cent of the present generating capacity of ECNSW. The estimates were based on the usage of surplus heat energy available from process heating. They ignore surplus heat from kilns and metals processing factories, and the potential for cogeneration using waste materials from the timber products industry and from methane extracted from old landfill areas.

Victoria

The Victorian Government's 1990 Green Paper (DITR 1990) suggests that a cogeneration capacity of about 585 MW is realistically achievable. Although no time horizon was specified, this represents around 7 to 8 per cent of current SECV generating capacity. The Green Paper estimated that, by the year 2010, cogeneration could provide about 15 per cent of electricity consumed.

South Australia

The South Australian Government provided information on current and proposed cogeneration projects in that State. Those currently operating or being commissioned have the capacity to generate around 75 MW of electricity. This is about 6 per cent of South Australia's electricity requirements. Proposed cogeneration projects have the capacity to generate around 79 MW. Of these, a proposal by Penrice Soda Products accounts for 70 MW.

7.6 Impediments to the development of cogeneration

Submissions and recent studies into cogeneration in Victoria, New South Wales and South Australia (Greene 1984, 1989 and SAEC 1985 respectively) claimed there are a number of market and institutional impediments to the development of cogeneration. These include:

- tariffs and charges for electricity purchases and sales;
- lack of information and uncertainty about official policies and attitudes;
- tax and investment appraisal differences;
- legal rights and safeguards; and
- fuel supply and environment issues.

Tariffs and charges for electricity purchases and sales

Tariffs and charges were of overwhelming concern. The economics of cogeneration depends critically on the value (and hence price) of the electricity it produces. Cogeneration can be used for replacing grid electricity purchases, to sell electricity, or a mix of both. Thus, the economics of cogeneration are heavily influenced by:

- the tariff and standby charges faced by purchasers of grid power; and
- the buyback tariff and charges faced by those selling power.

Leaving aside the issue of how the productive efficiency of utilities influences the level of prices, appropriate price signals depend on the pricing efficiency of the utilities. However, tariffs for industrial and commercial users do not generally reflect marginal cost very well. For example, industrial and commercial tariff users are discriminated against compared with domestic users in most states/territories. To the extent tariffs are 'too high', excessive levels of cogeneration will be encouraged.

Utilities apply specific standby tariffs to electricity purchases by cogenerators. These differ from the normal tariffs which would otherwise apply to purchases by firms engaging in cogeneration. The standby tariffs are imposed by utilities to cover the costs of their having generating capacity available to meet unexpected load increases, such as when a cogenerator cannot generate sufficient electricity for their own needs (due to plant maintenance, breakdowns, etc). However, allowances for these fluctuations are usually incorporated in standard tariffs. Except in special cases, such as where the cogenerator is a particularly large user of electricity (and thus its outage would place a significant demand on grid output), there seems little reason why charges for electricity supplied to cogenerators should not be levied in accordance with standard tariff schedules. Where special cases warrant, standby charges should reflect the capacity set aside by a utility to provide this power and the probability of such an outage.

Participants focussed mainly on the development of cogeneration for the sale of surplus power, particularly on what constitutes the 'correct' level of buyback tariff. BHP Steel - Collieries Division, Penrice Soda Products and the ACF, for example, claimed that buyback rates are too low and that (for BHP and Penrice) the proposed rates would mean further development would not be viable. Penrice Soda Products stated:

> Power buyback rates based on avoided costs do not reflect the true savings of cogeneration. They contain no allowance for reduced gas consumption, social and environmental savings and therefore do not take into account all of the implications for the Australian or South Australian economies. As total benefits are not acknowledged in offered buyback rates, the feasibility of the Penrice cogeneration proposal appears marginally uneconomic.

The principle governing the rate paid by a utility for electricity produced by a cogenerator is generally accepted as that of 'avoided cost'. That is, cogenerators should be paid for electricity at prices equal to the marginal opportunity cost that the utility would otherwise incur to produce it. Avoided cost is essentially the marginal opportunity cost of operating an electricity generating system. It can have a short run (operating) and a long run (capacity) element.

Participants differed on whether buyback rates should reflect avoided short run marginal costs or long run marginal costs. The New South Wales Gas Users Group stated the tariff for cogenerators should be based on the utility's long run avoided costs. Depending on the term of the contract and/or the balance between electricity demand and available supply, either could be appropriate. If a utility has surplus capacity, avoided costs will reflect short run operating costs. If, however, cogenerated electricity permits an authority to defer new generating plant (ie the authority is experiencing capacity constraints), it would be appropriate for the resultant avoided costs to be incorporated into buyback rates (ie they would reflect long run marginal costs). In this regard, the Queensland Government noted QEC buys cogenerated electricity:

> ... on the basis of its [QECs] assessment of the costs it avoids by purchasing such electricity. In the cases where electricity is supplied only as and when available, these savings are limited to fuel costs, but if a private operation is able to guarantee to operate to an agreed schedule, additional payments are made on account of the capital costs of generating plant which may be notionally avoided or deferred because of the purchased capacity.

The extent to which a utility will defer long run capacity increments depends on the surety that cogeneration capacity will continue to be available in the long run. Without any assurance of long run availability, utilities may be unwilling to alter their capacity expansion plans. Thus, if cogenerators are to receive buyback tariffs reflecting capacity deferral, authorities may require them to enter into contracts guaranteeing long term supply. This is already being done. ETSAs current cogeneration policy, for example, requires buyback supply contracts negotiated on an individual basis, preferably for extended periods such as 10 years. Equally, cogenerators may require utilities to provide some undertakings on the prices they will pay.

Avoided costs will also depend on the reliability and quality of electricity provided by cogenerators. This reflects such things as time of day, time of year, interruptibility of power, plant reliability, etc. These factors impose their own costs on a system and buyback rates and charges should vary accordingly. Buyback rates introduced by ETSA following a 1989 review incorporate some of these variables. For example, they vary for off-peak and peak hours, capacity factors, and time of year. They range from 2.5c/kWh in off-peak periods up to 10.6c/kWh for plants of very high reliability in specified peak periods (The Government of South Australia 1991, p. 50).

Desegregating avoided costs to reflect the factors that cause these costs to vary complicates buyback tariffs and may obscure price signals. Additionally, the effects of some variables are imprecisely known. Thus, procedures for setting buyback rates need to balance the potential gains from a more complex tariff against the benefits of a simpler one. One of the guiding principles for the 1989 review of private generation buyback tariff arrangements for ECNSW recognises this; `The arrangements should be as simple as possible ...'.

The practical problems of calculating avoided costs and implementing buyback rates based on them are essentially the same as the problems associated with estimating the marginal costs of producing electricity by a utility and setting tariffs for consumers based on marginal costs. In this sense, the problem of pricing electricity for cogenerators replacing grid purchases and for those who sell a surplus are the same (Joskow 1982, p.90).

A major difficulty with basing buyback rates on avoided costs is that utilities receive no gain from purchasing electricity from cogenerators. They could supply the electricity at the avoided cost themselves. They therefore have no incentive to support cogeneration. In this regard, Dr. R. Robinson (General Manager of North West Electricity) and Electricity Week note the self interest (of ECNSW) and that `... utility managers see cogeneration as an unwanted competitor, rather than as an important contributor to the efficiency in the industry'. Further, if utilities pay for cogenerated electricity at avoided costs, there is no scope for any lower costs achievable being passed on to customers. Any savings are appropriated by the cogenerator (Berry 1989, p. 479).

Utilities would have an incentive to encourage cogeneration if they shared some of the savings from lower cost electricity production (Joskow 1982, p. 95). The buyback rate in this case would be somewhere between the utility's avoided costs (the ceiling) and the cogenerators' costs (the floor). Some of the shared savings could be passed on to the utility's customers and part retained by the utility. However, as the sole buyer under existing arrangements, authorities are in a position to exercise market power. In this case, there could be grounds for government involvement to guard against abuse of market power. Alternatively, allowing cogenerators to sell power to anyone would subject the market power of the authority to competitive pressures. Buyback rates need not be based on administratively determined avoided costs. An alternative could be to invite cogenerators to bid for the supply of designated blocks of power. In this regard, the New South Wales Government noted prices may be determined by negotiations between private generators and electricity authorities.

Utilities could also be provided with an incentive to cogenerate if they took an equity interest in cogeneration facilities (Joskow 1982, p. 95). This would allow them to earn a rate of return on such an investment. Sagasco, whose interest in cogeneration is through natural gas fired plant, has provided something of a precedent for this. It has formed a company to promote cogeneration, offering a package which includes feasibility studies, finance, operation and maintenance.

Lack of information and uncertainty about official policies and attitudes

The studies by Greene and SAEC found a lack of familiarity on the part of large areas of industry about the potential benefits of investment in cogeneration. This was attributed to a lack of encouragement on the part of electricity authorities in some states and, equally, a lack of experience on the part of industry in designing and installing cogeneration equipment. In turn, the general lack of information and first hand experience in Australia acts as a barrier to consideration of cogeneration by financial institutions and business management.

Greene (1989) reported fairly negative views by industry and others on the attitude of ECNSW to cogeneration development. The study reported concerns about the past lack of interest and the current lack of clarity about cogeneration on the part of ECNSW, and a belief that County Councils viewed cogeneration as a privilege. Some companies indicated that they were reluctant to raise the issue of cogeneration with County Councils or with ECNSW in case their tariff structure was adversely affected. There was also a belief in some quarters that penalties would be imposed on consumers who installed cogeneration facilities.

Some steps have been taken to reduce uncertainty about government policies on cogeneration and to improve the availability of information, including technical, operational and safety aspects. For example, in 1989, the ECNSW established a working group to review private generation buyback tariff arrangements. Similarly, there have been initiatives to provide more information and clarify government policy towards cogeneration in Victoria and South Australia.

In Victoria, the Government (through SECV and DITR) is encouraging the development of cogeneration. As part of its State Economic Strategy announced in April 1987, the Victorian Government introduced its *Cogeneration and Renewable Energy Incentives Package*. This provides improved prices, terms and conditions for SECV purchases of electricity. Free consultancy and other facilitation is available to cogenerators (O'Neill 1990, p.21).

In South Australia, ETSA is encouraging cogeneration by making available its expertise in electricity generation and developing guidelines for evaluation of cogeneration schemes (Office of Energy Planning 1990, pp. 4-5). Sagasco has organised seminars on cogeneration for local architects, consulting engineers and potential users, in addition to forming a company to assist firms decide whether cogeneration is feasible for them (Office of Energy Planning 1990, p. 5).

Although there may now be less uncertainty and more information available to potential cogenerators, participants expressed concern about the existing arrangements. For example, Penrice Soda Products commented:

> It appears that ETSA cannot or will not establish buyback rates which reflect true savings without Federal or State Government policy first being established.

Uncertainty about long term prices for electricity can impede the willingness of firms to invest in cogeneration. However, uncertain prices are as inevitable for electricity (as fuel and interest rates change for example) as for any other product. To reduce uncertainty the utilities could publish regular guidelines on how their prices are determined. Industry uncertainty about technical and economic aspects of cogeneration could be overcome by firms offering equity in the cogeneration plant or contracting the entire operation to a specialist organisation.

Tax and investment appraisal differences

Major barriers to the development of cogeneration arise from the tax treatment and basis for evaluating cogeneration investments.

Electricity utilities tend to evaluate new generating investments on the basis of low real rates of return. Traditionally this has been on a tax exempt basis. Private sector evaluations of cogeneration generally apply much higher rates of return, and on an after-tax basis. The combined outcome of these differences is that investment in central generating plant is likely to be favored at the expense of purchasing electricity from cogenerators. If public utilities were corporatised, these problems would be largely overcome.

Certain other specific tax and depreciation treatment for cogeneration were also raised as barriers. These are addressed in Appendix 8.

When organisations view cogeneration as a non-core or discretionary investment it may have to satisfy far higher rates of return to be approved. The GFCV gave evidence of much higher rates being applied to non-core activities. Greene (1984, pp. 22-3) also found the problem of bias to investment in core activities to the detriment of cogeneration. However, as noted above, firms unfamiliar with cogeneration have the option of contracting with specialist suppliers for its provision. This puts cogeneration plants in the hands of enterprises which consider this investment a core activity (O'Neill 1990, p. 24).

These specialists could be either an arm of an electricity or gas utility (as Sagasco has now) or a specialist private enterprise. If specialist companies owned and operated many cogeneration plants they could exploit economies from specialisation and economies of scale with engineering, maintenance and operations (Joskow 1982, p. 95).

Legal rights and safeguards

A paper included as part of the APEA Ltd submission (Bradbrook 1989) argued that present legal rights and safeguards for cogeneration are deficient - and impede its development. The paper stated that:

> ... it is essential that suitable contractual arrangements should be made between each cogenerator and the relevant public utility ... whereby the utility provides a back-up facility for the cogenerator and purchases its excess capacity at fair, non-discriminatory rates.

It noted that utilities, with their monopoly position, can dictate the terms and conditions of both the sale of electricity to cogenerators and utilities' purchases from them.

To deal with this impediment, the paper suggested a comprehensive set of new statutory laws be incorporated into existing state electricity legislation. These would, for example, provide the right to sell to the grid, and purchase from it, electricity on a fair and transparent basis. The proposals outlined in the body of this Commission report, in particular those dealing with separation of functions, corporatisation and wheeling arrangements, deal with this problem. Their implementation would provide a framework in which the likelihood of discrimination against economically justified cogeneration would be significantly reduced.

Fuel supply and environment issues

Uncertainty about the potential rate of price escalation of the input fuel is also perceived to hinder the development of cogeneration. Long term contracts guaranteeing fuel price escalation at less than the CPI are not generally available (DITR 1990, p. 55). The DITR study considered the lack of long term gas contracts has contributed to the slow implementation of cogeneration projects in Victoria. BHP Petroleum commented that cogeneration is not being fully developed in Victoria because:

> GFCV has informed potential cogeneration entrants that the GFCV cannot guarantee supply for more than 5 years. ... BHP/Esso cannot in most cases supply direct to these potential entrants. This situation is caused by the structure of the industry.

The GFCV refuted this and claimed:

> In fact we guarantee supply. Price, on the other hand cannot be guaranteed due to contract conditions required by Esso/BHP.

Uncertainty regarding the supply of fuel for cogeneration has also been identified as a barrier in other states. The SAEC report (1985, p. 9) found that the uncertain availability of natural gas to South Australia after 1990 discouraged the use of gas turbines for generating electricity. Meekatharra Minerals Limited contrasted the uncertainties regarding the availability of long term contracts for gas supply with that for coal. It drew attention to:

> ... coal deposits such as the Arckaringa Basin with some 10,000,000,000 tonnes of reserves and thick flat seams which would enable users of this coal to enter into extremely long supply contracts at guaranteed prices.

Some potential cogenerators have access to alternative fuels, such as forest waste or by-products of production processes, which are presently not utilised. Policies on the pricing of pollution costs have the potential to improve the relative viability of cogeneration, using such waste as fuel or using a less polluting fuel source. Penrice Soda Products claimed a major obstacle to its receiving a viable buyback price was ETSAs unwillingness to acknowledge (and price) the environmental benefits of its natural gas fired cogeneration plant. On the other hand, environmental guidelines have the potential to restrict cogeneration in metropolitan areas. For example, cogeneration using gas turbines in the Sydney Basin may produce unacceptable levels of emissions.

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APPENDIX 8: INTERGOVERNMENTAL RELATIONS

The activities of the electricity and gas supply industries are affected by a wide range of Commonwealth Government interventions. However, Commonwealth legislation and/or procedures in relation to taxation, the Australian Loan Council, the Commonwealth Grants Commission and transitional arrangements are particularly relevant.

8.1 Introduction

While the electricity and gas supply industries are largely operated and regulated on a state or territory basis, the Commonwealth has an influence through several areas of activity. This appendix covers issues raised by utilities and other participants in four areas where these influences are important, namely:

- taxation;
- Australian Loan Council;
- Commonwealth Grants Commission; and
- transitional arrangements.

8.2 Taxation

8.2.1 Differential treatment of public and private activities

Different tax arrangements applying to private and government activities, and variations between governments, can have important effects on resource allocation. To the extent that most government utilities enjoy taxation advantages which are unavailable to private firms, public utilities' costs are lower and there is potential for resources to be attracted away from the private sector.

This means that, all other things being equal, government utilities would achieve a higher rate of return than would private utilities for a given project. In these circumstances there is an in-built bias which encourages public utilities to undertake certain investments themselves, rather than to employ private sector resources. As discussed in Chapter 5, the removal of state and local government tax exemptions, coupled with the payment to state governments of amounts in lieu of Commonwealth taxes and charges, would largely overcome tax and charge related biases affecting utilities' decision-making.

However, this would not remove biases in decisions at the state government level, in particular, evaluations of whether or not to privatise a government activity (or, alternatively, to acquire a private sector activity).

Participants raised the concern that, should state or territory governments privatise a utility, they may lose a source of revenue and this would act as a disincentive to ownership transfers. The AFCC noted that, where a state government would have collected a 'notional' income tax (in the form of payment in lieu of Commonwealth tax), a private project would result in this revenue payment being directed to the Commonwealth Government. CRA said this problem had been resolved in Canada where, for example, 95 per cent of Federal income tax collected from private power utilities is returned to the Provincial government. One difficulty with this type of arrangement is how to quarantine it to efficiency related improvements (ie such arrangements could provide an incentive for ownership transfers mainly aimed at increasing revenue rather than efficiency).

Recent events may have eased impediments to privatisation. For example, the sale of the State Bank of Victoria to the Commonwealth Bank incorporated a payment to the Victorian Government in compensation for the loss of 'tax' revenue the State would have otherwise received from the bank. The sale signaled the Commonwealth's willingness to examine compensation on a case-by-case basis. This issue was also addressed at the Special Premiers' Conference in October 1990 when the Commonwealth Government's in-principle policy of compensation was recognised.

The different tax regimes applying to public and private entities also creates problems for valuing enterprises considered for privatisation. Until changes are made to such matters as the treatment of depreciation of plant and equipment, capital gains tax, the availability of franking credits and the valuation of trading stock, any market value will remain uncertain. Without such changes, the true economic worth of activities for sale cannot be readily determined and potential sellers and buyers will be constrained.

8.2.2 Section 51AD of the Tax Act

CRA and the AFCC stated that the operation of the Income Tax Assessment Act on leases is a critical factor in the commercial viability of a project. The tax treatment of leveraged lease transactions (relating to Section 51AD of the Act) is particularly important in this area.

Leveraged leasing provisions permitted under a previous Tax Act were used to facilitate private ownership of Eraring power station and the Northern Territory private electricity and gas utilities. These provisions were later amended to restrict the application of leveraged leasing; changes which introduced considerable uncertainty for the industry. Since then, leveraged leasing has been the subject of a taxation ruling in June 1990 (IT2602). According to CRA, this ruling has significantly allayed industry uncertainty by providing an explanation of the circumstances under which Section 51AD would apply. However, AFCC claimed the ruling does not fully clarify the position and a degree of uncertainty remains until a 'track record' of specific decisions is available. Linked to this, CRA noted that tax rulings do not have the force of law. It therefore considered it is highly desirable that the Act itself be amended to embody the intention of the ruling. The implication is that failure to clarify this area will inhibit private investment in the electricity and gas supply industries.

While accepting that some uncertainty remains, it would be unrealistic and unwieldy to expect legislation to cover all eventualities. Thus, where appropriate, the necessity for any further clarification in this area will need to be considered by the Australian Taxation Office on a case-by-case basis.

8.2.3 Cogeneration tax restraints

Power Systems Australia (PSA) raised two tax issues which may hinder cogeneration developments: sales tax and depreciation.

PSA claimed sales tax legislation effectively adds 20 per cent to the capital cost of the same cogeneration plant when used in a commercial (eg a hotel) as opposed to an industrial application. In the latter it is considered an 'aid to production' and not subject to the 20 per cent rate of tax.

Considering sales tax in isolation is, however, misleading. The incidence of sales tax on inputs is related to whether the output of the industry is subject to sales tax. If the output is taxed, as in some industrial applications, the inputs are not (to avoid penalising them through 'double taxing'). If the outputs are not taxed, as in the case of some service industries, then the inputs are subject to sales tax.

On depreciation, PSA noted that:

> The current rules are drafted around the useful life of the plant. This is generally acceptable if the equipment is fully equity funded. However cogeneration plant is often debt funded over a shorter time period than the depreciation allowance Additionally due to gas supply and utility tariff uncertainties it is not possible to get 'back to back' contracts for fuel purchase or electrical sales matching the depreciation period and finance period. The net result is an increased cost and risk associated with project financed cogeneration plant.

PSA recommended that a schedule of increased depreciation be implemented for higher conversion efficiency or environmental type plant such as cogeneration installations.

This situation reflects the nature of depreciation (which is related to the useful life of an asset) and is not unique to cogeneration. There seems little justification for depreciation allowances to vary according to the manner in which plant is funded (ie equity, debt or some combination of the two).

8.3 Australian Loan Council

8.3.1 Background

The ALC coordinates the borrowing programs of the Commonwealth and state governments, and the programs of the larger semi-government and local government authorities. A Financial Agreement between the Commonwealth and the states provided the framework for Loan Council oversight of borrowings by Commonwealth and state authorities. Agreed upon in 1927, it was enacted in 1929. Borrowings by semi-government authorities were not initially included within the scope of Loan Council controls but, in 1929, a plan to coordinate such borrowings was adopted and this was formalised in 1936 as the Gentlemen's Agreement. This operated from 1936 to 1984. However, by the early 1980s, increasing use of 'unconventional' financing techniques outside the scope of the Agreement had eroded the Loan Council's influence over total borrowings. To rectify this, the ALC adopted a Global Approach on a trial basis in June 1984. The objective was to broaden the scope of the Loan Council oversight of authority borrowings by bringing them within voluntary limits all forms of borrowings. In May 1985, the Loan Council adopted the Global Approach on an on-going basis (Australian Government 1988).

While the new approach has given state authorities greater flexibility in their borrowing arrangements within and outside Australia, the main effect has been to confer upon the Loan Council wider control over government borrowings. As the Commonwealth effectively controls the ALC, the result of these changes is that:

> To all intents and purposes the Commonwealth is now able to control the fiscal transactions of State and local Governments in much the same way as those of its own departments and agencies. (Mathews 1984, p. 19)

8.3.2 Effects on energy utilities

The borrowing constraints resulting from the activities of the ALC operate at the state or territory government level. These constraints mean governments must subsequently ration limited borrowings between competing interests. This rationing can impact on energy utilities.

According to some public utilities (eg the SMHEA, SECWA and ETSA), Loan Council controls appear to have had little or no impact on their recent operations. However, the Western Australian Government considered the future availability of borrowings an important factor in determining whether its next major power station would be publicly or privately owned.

The GFCV stated that, to date, ALC activities had had no adverse effects on it with respect to debt levels or means employed to finance capital works. However, it added that this fiscal year was tighter, with some marginal projects not being funded; the result of receiving only 30 per cent of its borrowing requests. It noted that it was looking at a number of responses to this restriction, and that it is budgeting to be self-funding within 3 years.

ALC controls have altered the behavior of some other utilities. The ACTEW for example, was forced to increase its gross margins per dollar of electricity sales from 1988:

> ... because of a decision by the Federal Government in the Loan Council context to restrict borrowing by ACTEW. This required increased internal generation of funds to meet essential capital programs.

In the case of the Northern Territory, the Government stated that rationed access to loan funds has resulted in some economically justified projects not proceeding or alternative forms of financing involving the private sector being employed.

In its criticism of ALC controls, the Tasmanian Government referred to specific problems. It stated:

> State authorities are restricted in their ability to borrow to meet capital works programs by existing Loan Council arrangements. Under existing arrangements, the availability of capital funds for the ensuing financial year is not resolved until around the time of the Premier's Conference in June. The availability of funds for subsequent years is normally even less certain. This uncertainty hampers financial planning and the planning of physical works. Borrowing limits established on a three to five year rolling basis would provide more certainty for planning purposes. With greater pressures for commercialisation of the operations of electricity authorities it may be appropriate for authorities to have freedom to borrow without the existing restraints of Loan Council borrowing limits.

The Queensland Government also noted the impact on its ESI and was critical of ALC limits. Its concern was that the macro-economic policies of the Federal Government (pursued through Loan Council limits) could unnecessarily restrict the capacity of the State to meet its electricity supply industry's capital requirements. It stated that a global borrowing limit system in which one year's limit is determined primarily by reference to the previous year's level of borrowing is illogical. One year's borrowing requirements need have no relationship to the previous year's borrowings due to the lumpiness and volatility of capital expenditure.

The South Australian Government raised the issue of whether so-called commercial authorities should come within the global limits. It stated:

> So long as Governments do have the power to determine capital spending and financing levels of their authorities there seems little advantage in exempting such authorities from the global limits compared with maintaining those limits at economically appropriate levels. However the SA Government believes that public companies listed on the Stock Exchange that are subject to the Companies Act, such as Sagasco Holdings, should be removed from the ambit of the global borrowing limits because of lack of Governmental control over its investment and borrowing decisions.

Submissions from the private sector were also critical of the effects of ALC controls. The AFCC, for example, expressed concern at the impact of borrowing restrictions on the timing and size of necessary new power sources. It believes that, if current Loan Council controls are not changed, all public enterprises (including power authorities) are going to be squeezed for capital in the short to medium term.

8.3.4 Rationale for continued ALC control of borrowings

ALC control was originally intended to prevent competition for funds in the capital market between public enterprises and other governments agencies and the private sector, and to support the Commonwealth's macro-economic policy goals. Controls may also have reflected the concern that, in the absence of market disciplines, public enterprises would overinvest.

The capital market facing government borrowers has undergone radical changes in recent years. Deregulation of the Australian capital market and the greater exposure to international capital markets considerably weakens any justification for Loan Council control on the basis of preventing competition.

The issue of overinvestment is presently tackled circuitously through rationing borrowings. However, this provides no guarantee of preventing such excesses. Rationed funds can still be overinvested in activities where commercial justification is absent. Moves underway by governments to corporatise their utilities and to extend private generation will introduce greater commercial disciplines.

If the corporatisation measures outlined in Chapter 5 are adopted, public electricity and gas utilities would have a clear commercial focus and, in some areas, would face the possibility of direct competition. In these circumstances, they should be permitted to operate on equal terms with the private sector ie subject to commercial disciplines on borrowings rather than administratively imposed limits.

It was announced at the Special Premiers' Conference in October 1990 that the issue of whether government bodies operating in a fully competitive environment should continue to be subject to Loan Council controls will be settled at the next Loan Council meeting.

8.4 Commonwealth Grants Commission

The CGC is an advisory body which inquires into, and reports on, per capita relativity's which it regards as appropriate to apply when Commonwealth general revenue funds are distributed among the states and territories. The procedures used by the CGC are relevant to the electricity and gas supply industries since they can affect the charges applied to goods and services produced by government instrumentality's and the behavior of service providers.

The CGC applies the principle of fiscal equalisation to arrive at per capita relativity's. In doing so, the CGC has stated that it:

> ... estimates the general revenue assistance each State would require to enable it to provide government services at standards that are not appreciably different from those of the other States, without having to impose taxes and charges at levels appreciably different from those imposed by the other States.

The fiscal equalisation process involves a redistribution of general revenue funds from states/territories with high fiscal capacities to those with low fiscal capacities. As such, the process involves intergovernmental cross-subsidies on a large scale.

At present, the electricity and gas supply industries are excluded from the Commission's interstate comparisons. SECWA and the Western Australian Government argued that the natural disadvantages suffered by Western Australia, Tasmania and the Northern Territory, which lead to fundamental differences in the costs of energy supplies, justify compensatory grants.

Western Australia has argued this previously before the CGC (CGC 1988, p. 110.). At that time it argued that, if individual public business undertakings had an impact on the budgets of most states or suffered from substantial and quantifiable disabilities in particular states, they should be included in the Commission's comparisons. Western Australia supported the inclusion of electricity authorities in the comparisons by reference to advice obtained by the CGC during the 1981 review from the Attorney-General's Department. This indicated that government services should be taken to mean:

> ... not only all kinds of services provided by a State Government department, but also all kinds of services provided by any statutory authority or other body established for public purposes by State laws and financed from the moneys of the State Government or moneys of such an authority or other body.

At that time, in accordance with its general approach, the CGC did not accept the arguments of Western Australia and the Northern Territory in respect of the inclusion of electricity supply authorities. It acknowledged there were differences between the states in the costs of providing electricity and therefore (insofar as prices were based on costs) in the prices paid by consumers. However, as the electricity supply authorities were generally self-financing, the CGC considered there was little distinction between the nature of the services provided by them and other private goods where prices vary between and within states. The CGC was not convinced that the different cost structures of the electricity authorities in the states had any differential impact on the overall fiscal capacity of the state governments to provide government services.

The Northern Territory Government disagreed with the present CGC approach and methodology in this area and stated it will continue to argue for changes. In its case, the CGC includes in its assessment the recurrent cost of providing electricity to Aboriginal communities, but not the capital cost associated with its supply. The Northern Territory Government said these installations cannot be regarded as commercially advantageous, and their capital costs must compete with other essential capital funds; this is difficult when general purpose funds to the Territory have fallen from $171 million in 1985 to $43 million in 1990.

In its 1990 Report on Issues in Fiscal Equalisation, the CGC proposed for its next review (among others) to continue to assess states' differential revenue-raising capacities for contributions to their budgets from electricity and gas undertakings (CGC 1990, p. xvii). However, it appears unlikely that electricity and gas undertakings would be included as the Commissioners judged them primarily commercial in nature, in that they are capable of fully recovering costs from users (CGC 1990, p. 75).

The Industry Commission's view on whether government electricity or gas utilities should be included in determining per capita relativity's accords with that of the CGC expressed in the 1990 Report. That is, where utilities are providing a private good and are capable of recovering costs, there is no justification for inclusion in CGC deliberations.

8.5 Transitional arrangements

Changes currently being made to the industries will result in both costs and benefits. If these remain internal to the state/territory implementing them, incentives for governments to pursue such reforms are not diminished. For example, while the SECV may incur retrenchment costs in pursuit of improved productivity, that higher productivity brings lower prices for Victorian users and/or increased dividends to the Victorian Government.

However, when the benefits of reforms are external to the government implementing them, the incentive for change will be weakened. This is the case with the transfer of tax revenue dealt with above. Where such a mismatch of costs and benefits occurs, there is the danger that reforms of net benefit to the community will be foregone. This raises the issue of whether the Commonwealth should provide special assistance compensating state/territory governments to facilitate reforms.

Whether special assistance to compensate governments is required and the form it may take depends on the nature of the problem. As noted above, special problems such as the loss of state revenue have resulted in an in-principle decision on compensation arrangements. The October 1990 Special Premiers' Conference also resulted in agreement that the transitional funding of reforms with large up-front costs and delayed benefits can be accommodated within special additions under the Global Approach to Loan Council borrowings. Other problems arising from reforms may be of a more general nature and adequately addressed through existing policies.

Within a state/territory, this same mismatch may occur. Some participants claimed the costs of reform will fall inequitably on some groups (for example, people in the Latrobe Valley), while the benefits accrue to the community in general. It is, however, the role of state/territory governments to balance such competing interests in making their decisions. Moreover, it is not a problem unique to changes in the electricity and gas industries. The rest of the economy is also faced with adjusting to a constantly changing environment.

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APPENDIX 9: REFORM INITIATIVES IN OVERSEAS COUNTRIES

Regulatory developments in other countries may provide some guidance to the organisation of the electricity and gas supply industries in Australia. An examination of overseas electricity supply industries reveals that Australia has a relatively high degree of both public ownership and vertical integration in its electricity industry. Reform initiatives in countries such as the United Kingdom and New Zealand are intended to result in segmented, privately owned industries.

9.1 Introduction

Developments in overseas energy industries highlight areas of possible importance for the gas and electricity industries in Australia. In this Appendix, the past and current structures of overseas energy industries, and some of the present developments occurring in these industries, are considered.

An overview of recent developments in world markets, with particular emphasis on the impact of changing technology and more uncertain demand conditions is provided in Section 9.2. Following this, the structure and operation of the electricity industry in 16 overseas countries are considered (Section 9.3). The attachment to the Appendix provides detailed information about the regulatory conditions governing the electricity and gas industries in New Zealand, the United States and the United Kingdom.

Published information covering the gas supply industry internationally is limited. Consequently, the treatment of the gas industry is less detailed than that of the electricity industry in this Appendix.

9.2 Overview of international trends in energy industries

9.2.1 Electricity

Until the late 1960s, the ESI in most countries experienced strong and consistent growth. Associated with this growth were technical improvements and falling real costs and prices. However, since the early 1970s several important factors have changed.

On the demand side, the most notable of these was the onset of the oil price shocks which led to price increases for both primary fuels and electricity. Subsequently, demand has increased more slowly, and demand projections imply relatively subdued growth, although there is a considerable margin of uncertainty. The costs of inaccurately forecasting demand were felt in many countries during the 1980s in the form of excess capacity and associated cost increases.

Electricity consumption in the OECD increased by 4.5 per cent in 1987, and 4.1 per cent in 1988. In both years electricity consumption growth was higher than both economic growth and growth in total energy demand. The IEA (1989, p.27) notes that the importance of electricity is increasing due 'to structural changes in industry and increasing advantages of electricity use in new industrial processes'.

On the supply side, several technical developments have influenced the nature of the industry. Recent advances have increased the economic attractiveness of gas use in electricity generation. New technologies such as regenerative gas turbine cycles, fluidised bed combustion, combined cycle generation, and co-generation systems have been adopted in many countries. This has reversed the trend towards ever larger production scales that had been evident since electricity's first introduction. For example, maximum turbine ratings increased from 5 MW in 1900, to 1300 MW in the early 1970s. At the same time there has been a commensurate fall in the number of generating companies. For example, in the United States the number of electricity companies fell from 4000 in 1917, to just over 200 in 1983 (IEA 1985, p.26).

Other issues that have influenced the ESI include:

- the development of nuclear power stations, in the 1950s, with the expectation that they would provide abundant, cheap electricity. However, while the incremental cost of nuclear fuelled electricity is extremely low, the capital costs have proved almost debilitatingly large after the inclusion of safety, environmental and decommissioning requirements;

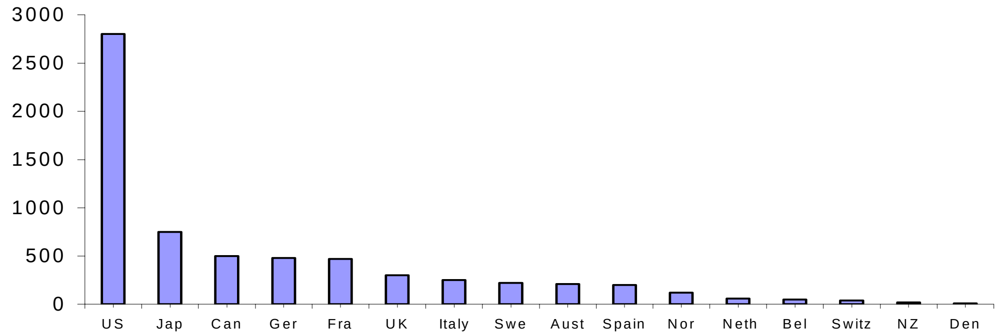
- the end of long-run trend of declining electricity prices primary due to primary fuel price increases, difficulties in achieving continued increases in thermal efficiencies, and increasing costs and longer lead times for new electricity stations;

- the completion of new stations has also been hampered by concerns about nuclear proliferation, safety considerations, environmental risk, and delays in construction; and

- electricity tariffs have been held artificially low in many countries in support of income redistribution and industrial development goals of governments. Electricity supply has been viewed in many countries as a public good suited to public provision, and subject to political intervention to fulfil social objectives.

Figure 9.1 shows that, in 1988 the output of ESIs was similar to that of Spain and Sweden, but only five per cent of that of the United States' ESI.

Figure 9.1: Comparison of ESI output, 1988
(Terawatt hours)



Source: IEA (1990) and Holmes (1990)

9.2.2 Natural gas

In contrast to the maturity of most electricity markets, and the centralisation of ESI organisation, the natural gas industry worldwide is in a much less developed state. However, because of technological developments, readily available supplies and increasing environmental concerns, natural gas has significant growth potential in several markets, including those far from supply areas.

The market for natural gas in most countries grew out of that for coal-based town gas. The IEA notes that these markets are diverse and at different stages of development in various OECD countries. There are considerable differences in the share of natural gas in the primary energy balance, the organisational structure of the gas industry, consumption patterns in various sectors, and the degree of self sufficiency. Such differences are in part due to the disparate endowments of natural gas between countries. For instance, in the established markets of North America and Europe, natural gas accounts for 20 per cent of primary energy. In the Netherlands it exceeds 50 per cent. But in Japan, where natural gas is imported, the share is less than 10 per cent.

Countries such as Greece, Norway, and Portugal are in the process of establishing domestic gas markets.

9.3 The electricity and gas industries in selected countries

This section highlights important characteristics of the electricity and gas industries in selected countries. In addition to Australia, it covers:

Belgium	Canada
Chile	Denmark
France	Germany[1]
Italy	Japan
Netherlands	New Zealand
Norway	Spain
Sweden	Switzerland
United Kingdom	United States

9.3.1 Electricity

The IEA (1990) notes that many countries are moving away from 'traditional, centralised electricity generation towards smaller, more decentralised forms of supply and growing competition'. Private power is being promoted in many countries.

Table 9.1 presents the main features of the electricity industries in each of the aforementioned countries.

System of government

Of the countries studied, Australia, Germany, Canada, Switzerland and the United States have federal systems. The remaining countries are centrally governed, although several have provincial or similar divisions. Two aspects of government influence on the structure of the electricity industry are particularly worth noting: most countries utilize some form of municipal or local authority to organise electricity distribution; and central government control of the ESI is rare.

Fuel mix There are considerable variations in energy resource endowments between countries. Australia has relatively abundant supplies of low price coal and gas. However, its hydro resources are limited, and nuclear electricity generation is not judged to be economic.

1 Available statistics refer to the Federal Republic of Germany's ESI prior to unification with the German Democratic Republic. Since that time, it has incorporated the former Democratic Republic's ESI.

Table 9.1: Regulation of the electricity supply industry in selected countries

	Australia	Belgium	Canada	Chile	Denmark	France
Government	Federal/State	Central/Provincial/Communes	Federal/Provincial	Central	Central	Central
Output (Twh 1988)	140	65	504	17	28	392
Primary Fuel -(1988)	79% coal 11% hydro 9% gas	65% nuclear 25% coal 5% gas	61% hydro 18% nuclear 19% coal	68% hydro 30% coal	92% coal 5% oil	67% nuclear 20% hydro 9% coal
Organisation	States own system and some coal.	Communes responsible for distribution.	Provinces supply and own natural resources.	Very little state intervention.	Very little state intervention.	State ownership
Ownership	93% public	97% private	Primarily public	90% private	100% private	100% public
Main Entities	State electricity commissions, municipal, regional distribution authorities.	Three generating companies, system coordination done by CPTE, which is owned by generators.	Public and investor owned utilities operate in each province. 43 utilities supply 90% of Canada's electricity.	Two pooling systems, SIC & SING, coordinate 15 generating companies.	12 undertakings own 18 power stations, coordinated into east and west divisions under two organising bodies.	One organisation, Electroctile de France (edF), is responsible for all aspects of electricity production.
Industry Structure	Varies, high degree of vertical integration. Distribution separate in 3 states.	Distribution separate.	High degree of vertical integration, except in Ontario, where distribution is separate.	Most companies generate and transmit power to local distributors. There are 18 separate transmitters.	Complete vertical integration.	
Primary Regulation	State enabling legislation. Obligation to supply.	Electricity Distribution Act of 1925.	Provincial enabling legislation.	State enabling legislation.	Electricity Supply Act authorises production and transmission licences.	
Other features	Reform options being considered, particularly greater interstate cooperation.	Belgium has the highest proportion of nuclear generation of IEA countries	There has been a trend towards increased public ownership of utilities in the provinces.	Privitisation took place over an extended period following 1973	All coal is imported. Companies run as 'service' organisations rather than profit making companies.	EdF is encountering severe overcapacity problems associated with its nuclear program.

	Germany (FRG)	Italy	Japan	Netherlands	New Zealand	Norway
Government	Federal/Lander	Central	Central	Central/Provincial	Central	Central
Output (Twh 1988)	431	204	754	70	29	110
Primary Fuel -(1988)	53% coal 33% nuclear 7% gas	72% thermal 21% hydro	28% oil, 26% nuclear 18% gas, 15% coal 11% hydro/geothermal	50% gas 38% coal 6% nuclear	80% hydro/geothermal 18% gas	99% hydro/geothermal
Organisation	Very little state intervention.	State ownership	Very little state intervention.	Primarily provincial/municipal owned public companies.	Central and municipal.	Central and municipal.
Ownership	Generation 100% private.	83% public.	95% private.	90% public.	100% public.	80% public
Main Entities	960 utilities and undertakings operate under several coordinating associations. 5 major generating companies	The public utility, ENEL responsible for production, transmission and distribution. Also 17% cogeneration.	9 regional generation utilities and 33 small municipal generators.	61 generators and/or distributors supply 71 municipal distributors. 10% electricity is cogenerated.	Electricity Corporation of New Zealand generates and transmits power to regional distribution authorities.	The public utility, Stalkraft generates 25% of electricity. Regional utilities the rest.
Industry Structure	Varies, distribution largely undertaken by municipal authorities. Generation & transmission co-ordinated by VEW.	ENEL generates, transmits and distributes almost all electricity. Small amount of municipal distribution.	Regional utilities are vertically integrated.	The industry is vertically disintegrated, with transmission undertaken by a coordinating organisation.	Transmission and generation are integrated, distribution is separate.	Stalkraft owns 80% of the transmission grid. There are 258 municipal distributors.
Primary Regulation	Electricity Tariff Supervision Authorities of the Lander approve domestic tariffs.	The Nationalisation Act enables ENEL, but allows small scale private production	1984 Electric Utility industry Law, in effect, grants monopoly areas.	Pricing is on a cost-plus basis, subject to potential intervention by the Economics Minister.	The industry is subjected to the competitive provisions of the Commerce Act.	The Electricity Act grants utilities sole supply rights & the obligation to supply.
Other features	Utilities operate at local, regional, and interconnected levels. There is great variety in their size and scope.	ENEL has abandoned nuclear power, and has encountered enormous problems in constructing new power stations.		The Netherlands has the highest reliance on gas in the OECD.	The New Zealand electricity market is being deregulated, after corporatisation is 1987. See attachment.	Future system expansion will utilise Norway's North Sea gas assets.

	Spain	Sweden	Switzerland	United Kingdom	United States
Government	Central	Central	Federal/cantons/communes	Central	Federal/State
Output (Twh 1988)	139	147	81	308	2872
Organisation	35% nuclear 33% coal	48% hydro/geothermal 48% nuclear	59% hydro/geothermal 37% nuclear	68% coal 20% nuclear 9% oil	58% coal 19% nuclear 9% gas, 8% hydro
Ownership	80% private	70% public	65% public	100% private	77% private
Main Entities	9 private and 3 public generators. 8 private and 2 public distributors	State owned Vattenfall generates 50% of power, private and municipal utilities generate the rest.	About 1200 generation and distribution companies owned by communes and cantons.	3 generating companies, a national transmitter, & 12 distribution companies.	There are 3388 private and municipal utilities, rural co-ops, and federal systems.
Industry Structure	51% public REDESA operates grid and despatch	The state utility owns the transmission grid, distribution is owned by a variety of bodies.	Minimal vertical integration.	No vertical integration, although distributors jointly own the transmission company.	90 per cent of private utilities are fully vertically integrated, and many are organised into regional power pools.
Primary Regulation	Heavy regulation, centered on the 1983 National Energy Plan (NEP).	The right to expand the grid is confined to the state power utility.	The only federal government regulation is nuclear station licencing.	The government regulates areas not subject to competitive pressure EG. Transmission.	The industry is regulated by the FERC which overseas interstate rates. PURPA legislation promotes admission of co-generators to the grid.
Other features	Under the NEP no further nuclear plants are to be constructed.	The Swedish transmission grid is the backbone of the joint nordic power system, Nordel.	The Swiss system involves many small scale undertakings, some private, some held by local authorities as stock companies.	The UK system is being reformed from a structure similar to NSW, to being perhaps the most pro-competitive system in operation.	

In 1988, coal was the biggest fuel input into electricity generation in OECD countries. Table 9.1 shows that in that year, Australia relied on coal for 79 per cent of its electricity fuel input. This was the second highest level of any country surveyed. The highest was Denmark, which used coal to generate 94 per cent of its electricity. Other countries that rely heavily on coal include Britain (71 per cent), Germany (55 per cent), and the United States (58 per cent). Australia has a lower reliance on oil and hydro power than the IEA average.

Nuclear fuel accounted for 24 per cent of total IEA electricity fuel inputs in 1988. The IEA (1989, p.36) notes that, while nuclear power is still a very cheap source of energy, it no longer enjoys undisputed cost advantages over other methods of base load electricity generation because of falls in the relative price of fossil fuels. Even so, it was the fastest growing fuel source for electricity in 1988.

Regulatory profile

An examination of international regulatory arrangements reveals a focus on a few specific regulatory tools:

- price controls, based on cost of service, rate of return or some price index;
- enabling legislation, granting exclusive operating licences to regulated areas;
- requirements obligating distributors to supply customers within a franchised area;
- trade practice/anti-trust legislation; and,
- controls on the construction, size, location and environmental impact of power stations.

Of these regulatory forms, price controls are most frequently encountered. These may take a variety of forms. In Canada, electricity rates are set according to revenue requirements, that is, cost plus a rate of return sufficient to maintain financial viability. Similar rate-setting principles are employed in Japan and the United States. In Germany, however, electricity prices are subject to approval by supervising authorities. They are subject to a levy used to support the price of domestic coal. In addition, electricity generators are limited in their access to cheap imported coal.

Industry structure and ownership

The countries examined display considerable diversity in the pattern of ownership and degree of vertical integration of their ESIs. The countries where vertical integration is greatest are Australia, Canada, France, Italy, Japan and the United States. Vertical integration is least in the reformed English and New Zealand ESIs, as well as in Denmark, the Netherlands and Switzerland.

For example, in both France and Italy, a central electricity authority is responsible for all aspects of electricity production. However, the French utility, Electricite, de France (EdF), has received much greater government and public support than the Italian utility, ENEL. EdF has grown to be one of Europe's largest utilities, with the highest proportion of nuclear plant of any country. In contrast, the German ESI is extremely decentralised, consisting of around 960 individual undertakings. Companies operate at local, regional and interconnected levels. These companies are variously responsible for either or all of generation, transmission and distribution. Local municipal authorities are largely responsible for electricity distribution, as well as the distribution of water and gas. Most utilities are organised under the umbrella of one the several coordination organisations.

Apart from countries, such as France and Italy, where the industry is fully integrated under the aegis of a single utility, generation and distribution are typically the responsibility of several (and sometimes numerous) organisations. However, the same cannot be said for transmission, which is usually organised as a separate activity. It may be either owned and run by a separate organisation, or owned by a variety of organisations but run by a governing system coordination body. For example:

- In Belgium, generation, transmission, and distribution are privately owned, and vertically separated. Three generating companies supply electricity through a transmission grid, owned by a variety of interests, to independent distributors. System coordination is the responsibility of the CPTE (Societe, pour la coordination de la production et du transport de l'energie electrique), which is composed of all generation companies.

- A similar situation exists in Denmark where, due to geographical considerations, the ESI is operated as two separate divisions, each run as a power pool under single system coordination bodies, ELSAM and ELKRAFT. They oversee the activities of the 28 organisations that participate in electricity transmission. Distribution is highly decentralised, with some 120 enterprises undertaking this operation.

Analogously, the various European grids are coordinated by a system coordination body which governs transmission of electricity over each entire system. The UCPTE performs this role through the Laufenburg control centre (which is run by a private company). In the Scandinavian countries, Nordel is the coordinating body, through the Swedish national control centre (see Appendix 10). The bulk of international electricity transactions in the European system have been opportunity interchange rather than trade, with tallies metered at the Laufenburg centre. This has been changing with greater exports from France. More detail on these and other pooling and coordination agreements is provided in Appendix 10.

Electricity distribution is undertaken by smaller organisations in many countries. These organisations are often municipally owned. For example, in Belgium, distribution is mainly the responsibility of local communes, and is organised under a separate legal regime from other ESI activities.

Reform initiatives

Reform initiatives have recently been undertaken in the ESIs of a number of countries. For example, considerable restructuring has occurred in the United Kingdom, New Zealand, Netherlands and Spain. Major reforms have also been slated by the EC Commission. There have been less sweeping reforms in other countries, such as the United States and Spain. These various reforms have addressed a number of areas considered in this report, such the coordination of the transmission grid, open access, ownership, competition and the optimal number of generators. For example:

- *United Kingdom* - The former public monopoly of the Central Electricity Generating Board (CEGB) has been removed in favour of a privatised (non-nuclear) competitive generating sector, privatised regional distribution companies and an independent national transmitter, the National Grid Company (NGC). The competitive centre of the reformed industry is the coordinating role of the NGC, which operates an electricity spot market. Participants on this market will include the distribution companies, large individual users, the generating companies and other licenced suppliers. These will bid on this market for the supply and sale of electricity, in theory providing the impetus for efficient electricity supply and planning.

- *European Community* - The EC Commission announced in March 1991 that open access would be introduced on both electricity and natural gas pipelines throughout the Community. This will end the monopolies of national authorities on electricity supply. Consequently, any EC energy supplier will be able to distribute energy through any transmission network in Europe.

- *New Zealand* - Under the reforms being introduced to the ESI, generators and distributors will form a 'club' to own and operate the transmission grid. The club will operate as a company under the provisions of the Commerce Act, with the government retaining some voting rights. Options for the break up of generation into two or three companies are being considered.

- *Netherlands* - Since 1986, the number of generating concerns has been reduced from 15 to four. The remaining generating companies continue to own SEP (The Cooperating Electricity Producers Ltd.) which controls the national grid. A government plan to nationalise the transmission network has apparently been dropped. The generators themselves are owned by roughly 70 distributors, many of which are municipally owned. Regional monopolies in distribution have been broken. Companies can now buy from alternative suppliers, and large companies can buy from any distribution company. Government price setting has been retained in the complex grid buy- and sell-back arrangements.

- *Spain* - The Government reevaluated the planned nationalisation of the ESI, largely due to the debt ridden state of the industry. Instead, the transmission grid was separated and nationalised. It had previously been owned by 23 utilities, which along with government took responsibility for system coordination functions.

9.3.2 Natural gas

The IEA notes several developments in natural gas regulation internationally:

- *New Zealand* - The gas industry's main entity, Petrocorp, is a vertically integrated utility. The Government sold its 70 per cent stake in Petrocorp in late 1987, as well as removing exclusive franchise provisions for Gas supply.

- *United States* - The US natural gas industry is dominated by privately owned producers, pipelines and distributors. Formerly tight federal and state rate regulation has been progressively relaxed, with all remaining wellhead price ceilings due to be removed by 1992. The phased and uncoordinated policy reforms in response to changing conditions since the 1970s have incurred significant follow-on costs, with consequent disadvantages for consumers.

- *United Kingdom* - the UK gas industry was privatised prior to the electricity industry, and the reform plan has been subject to criticism from several quarters. The chief criticism was that the government transferred a public utility to the private sector intact. It has consequently been seen to have traded a public monopoly for a private monopoly, without realising the competitive benefits that privatisation is intended to capture.

- *European Community,* the reform program referred to above for the electricity industry applies also to natural gas, with full common carriage to be implemented across borders. Additionally, the IEA (1989) notes that increased price transparency will be required for, *inter alia*, industrial users.

ATTACHMENT 9.1: Selected international case studies

Introduction

The regulatory history of the electricity and gas industries in the United States, the United Kingdom and New Zealand are examined in this Attachment. These countries have faced issues similar to those now being encountered in Australia.

The gas and electricity industries in New Zealand and the United Kingdom are of interest because of the extensive reform programs they have undergone.

The United States case study highlights the problems confronted by regulated private utilities. These include contractual problems faced by the companies themselves, particularly in the gas industry, and also problems encountered from the regulators' point of view.

United States

Electricity

Background

The United States electricity market is the biggest in the world, being some four times the size of the next largest ESI. In excess of 3000 enterprises are engaged in the generation, transmission and distribution of electricity in the United States. In the generation sector, the concentration of firms is high. Some 200 (or 7 per cent of the total number of enterprises involved in the industry) investor-owned utilities (IOUs) generate between 75 and 80 per cent of electricity supplied in the United States.[2] The remainder is generated and distributed by 3000 publicly or cooperatively owned entities that vary widely in size, organisational structure and ownership.[3]

IOUs are usually vertically integrated. They generate, transmit and distribute electricity to retail customers. As distributors, they typically have an exclusive franchise to provide service to retail customers within defined service areas, with an associated obligation to supply. Multiple franchises are rare in the US.

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2 After consolidating utilities that are wholly owned subsidiaries of holding companies and jointly owned wholesale power facilities, and ignoring very small integrated distribution companies, the number of independent IOUs is in practice reduced to 100.

3 These entities include federal power marketing agencies (eg Tennessee Valley Authority), state and municipal utilities, cooperative distribution entities and rural electric co-operatives.

In the past, IOUs served customers independently. However, as demand grew and the size of generating capacity increased, existing utilities found that they were too small to exploit all available scale economies. Hence, joint ownership of generating capacity became common. Developments in transmission and coordination technology led to increased interconnection between independent IOUs, and subsequently, joint planning and operation of facilities and the development of formal power-pooling arrangements to enhance reliability and realise further cost savings (see Appendix 10).

Electricity generation is also undertaken by independent industrial and commercial establishments. These have become more important in recent years due to legislative changes and the development of more efficient small scale technologies.

State regulatory processes

Public utility companies are organised pursuant to state law, and are authorised to do business by the states in which they have facilities and make sales. Franchising authority usually rests with the state, or with individual municipalities, or is shared by both. All states with private utilities now have public utility commissions (PUCs) which regulate prices.

Utilities are required to submit any proposed changes to the level and structure of tariffs to State Commissions. The administrative proceedings for changing prices are termed 'rate cases', with prices fixed between rate cases until new tariffs are approved. Commissions can also establish terms and conditions governing line extension requirements, billing procedures and service quality. They also issue certificates of convenience and necessity to allow the addition of new plant and equipment, supervise franchising and refranchising, approve mergers and acquisitions. Additionally, they are sometimes involved in electricity supply planning and operation issues. Details of regulation differ considerably between states.

Federal regulation

Federal regulation of the ESI is the responsibility of the Federal Energy Regulatory Commission (FERC). The FERC's authority is limited to the regulation of the rates, terms and conditions of wholesale transactions.[4] Vertically integrated utilities consequently tend to be subject to state rather than federal regulatory processes, since they do not need to undertake wholesale transactions with separate corporate entities. However, a variety of wholesale transactions are made by IOUs. These transactions fit into two broad classes:

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[4] Mergers are also subject to the approval of the Securities and Exchange Commission (pursuant to the Public Utilities Holding Company Act of 1935). The Department of Justice has also been involved in merger cases and the Nuclear Regulatory Commission can undertake antitrust reviews.

- *Coordination transactions*, encompass the short-term purchase and sale of electricity by interconnected utilities. This includes power-pooling arrangements. Coordination transactions are generally associated with surplus generating capacity in one system. Some 20 per cent of electricity generated by IOU's is sold to other utilities through coordination transactions.

- *Requirement transactions*, involve the sale of electricity by integrated IOUs to an unintegrated, or partially integrated, distribution company that does not own sufficient generation or transmission capacity to meet its own requirements. Most of these unintegrated or partially integrated purchasers are municipal or cooperative distribution utilities, operating within the control area of an integrated utility. Under a requirement contract, a selling utility must stand ready to supply all the net requirements of the buyer. These transactions are heavily regulated by FERC using rigid cost-of-service principles. These transactions account for about 10 per cent of IOU generation (Joskow 1989).

The FERC also regulates wheeling transactions, although it can only regulate rates and not the use of transmission facilities by other parties.

Historical operation of the regulatory framework

Since the mid-1970s, the US ESI has faced problems in engineering, management and finance. Many of these problems have been attributed to state and federal regulatory processes which progressively reduced the ability of the industry to respond to changing market circumstances.

Regulatory problems and changing cost conditions in the 1960s

Between the 1920s and the 1960s there was a downward trend in real electricity prices associated with the declining real price of petroleum, increased thermal efficiencies in generation and greater scale economies in generation and transmission. High demand growth eased the introduction of these changes.

But aside from these positive external developments, there were incentive problems associated with the regulatory system itself. The industry's cost-plus pricing system, combined with the rate-of-return regulatory regime, was backward looking. It was based on historical costs rather than opportunity cost. Consequently, the industry faced a problem of 'regulatory lag', where rate setting did not reflect current costs.

During the industry's long growth period, this 'regulatory lag' had allowed utilities to earn returns on investment greater than their cost of capital. Up until the 1970s these inflexibility's were masked by the general decline in prices mentioned above. Consequently no political motivation existed to challenge the efficacy of the regulatory apparatus.

But from 1969 an extended reversal of cost conditions began for the electricity generation sector. The previously rapid improvements in technology slowed, more stringent pollution standards were applied, petroleum prices began an upward spiral, and higher inflation impacted severely on the industry's non-energy inputs (Smith 1988, p.16).

Regulatory response

In response to these rising cost conditions an increasing number of applications for rate increases were filed. But interest groups opposed to electricity price increases exerted pressure in the formal hearing process against these applications. The 1973 oil price shock resulted in much larger rate increase requests, and commensurate intensification of political resistance to such change (Joskow 1989, p.126).

Considerable pressure was placed on the regulatory process, which had not had to deal with sustained cost increases and repeated formal rate hearings since state commission regulation was introduced in the early 1900's. Regulators were swayed by political factors [5], so that IOUs faced concerted opposition to their rate increase applications, even in cases where they were justified on cost grounds. Joskow (1989, pp.152-153) has argued that:

> In the end, utilities had a very difficult time recovering costs they had expected would be afforded traditional cost-of-service treatment through the ratemaking process.

In these new conditions, regulatory lag kept prices below accounting cost of service, and earned returns below the cost of capital.

Consequently, price increases lagged behind cost increases for the utilities, so that the industry experienced reduced profitability. After 1973, the earned rate of return on equity did not keep up with changes in interest rates. Further, a growing fraction of earnings took the form of non-cash accounting credits, which assumed that generating plants currently under construction would eventually be included in the rate base, and earn a return on the associated investment. Smith (1988, p.16) considers that this was a reasonable assumption, given that:

> ...the regulatory environment had long promised rates that would yield the revenues required to cover costs plus a reasonable profit.

Cost disallowance's and the utilities' response

A further cause of cost increase, which was to have most impact in the early 1980s, was the decision by many utilities to undertake nuclear plant construction programs to meet high levels of expected demand growth. This technology offered a new source of scale economies and the prospect of very low cost fuel. In the event, the high capital costs associated with nuclear power offset these benefits.

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5 Regulators were appointed by political representatives, or in some states were elected.

Also, forecast loads did not eventuate.

Consequently, there was considerable pressure for utilities to increase their rates to cover resulting overruns.

> Giving these new plants conventional rate-base or cost of service treatment often implied large rate increases on top of rapid increases in fuel prices and other operating costs. As a result, regulatory commissions came under considerable pressure to resist including the costs of the plants in the rates. (Joskow 1989, p.160)

Many regulatory commissions responded by subjecting new power plants to ex-post "prudence" reviews. When these reviews could not show that investments were imprudent, they sometimes simply changed the rules by taking the position that cost of service compensation could only be provided if the economic value of the plant was greater than its accounting cost. This was known as the 'used and useful' concept, and made it possible to disallow cost claims caused by excess capacity. Recently, there have been a number of cases in which the costs of new plants have been wholly or partially disallowed for inclusion in the rate base on the grounds of imprudence (Joskow 1989).

In response to these problems, the utilities have moved away from the construction of large new generating plants. They have instead sought other methods of balancing demand and supply which involves less financial risk, such as extending the life of existing plants, increasing bulk power transfers between regions, increasing imports of electricity from Canada, encouraging energy conservation, improving load management and installing less capital intensive technologies.

Some commentators have suggested that the utilities are now under-investing in new capacity. The *Energy Security Report* (1987) noted that even under cautious assumptions - 2 per cent demand growth per annum and 50 years of plant life - the United States would need an additional 100 GW of new generating capacity beyond that already under construction by the year 2000 to maintain adequate electricity supplies (IEA 1989, p.572).

Existing utilities are also disadvantaged by the net subsidies conferred on public firms. Publicly owned utilities are exempt from federal income taxes and in many cases from state and local taxes. In addition, public enterprises have been able to borrow at rates of interest below those available to a private firm.

As a result, public firms have significant advantages in the current situation. Given that IOUs have little incentive to install additional capacity under the current regulatory arrangements, public enterprises have been seen as an attractive source of generation and transmission capacity.

The PURPA legislation

In an attempt to solve some of the problems faced by the energy industry in the 1970s, the Federal Government introduced the Public Utility Regulation Practices Act (PURPA) in 1978.

The most significant part of this statute requires that access to transmission grids owned by utilities be made available to owners of cogeneration facilities and small independent power producers. Cogenerators and small power production facilities that qualify under PURPA are referred to as "qualifying facilities" (QFs). QFs are restricted to a narrowly defined range of technology and size categories by the statute.

The legislation directed the FERC to issue rules defining the criteria that independent suppliers have to meet to be classified as QFs. It also instructs the FERC to specify the methods used in determining the rates at which utilities purchase power from QFs. The only specific guidance in the statute is that rates must be reasonable and non-discriminatory, and that utilities should not be required to purchase electricity at rates in excess of the marginal cost of alternative power sources.

In 1980, the FERC responded to the PURPA legislation by specifying that the relevant prices were to be determined using the principle of 'avoided-cost'. Further, the implementation of ratemaking was delegated to the state regulatory commissions. Under the avoided-cost approach,

> ...the price the utility is obligated to pay a QF should reflect the cost that the utility avoids by purchasing from an independent supplier compared with what the cost would have been if supplies had been made from the best alternative available. (Joskow 1989, p.164)

The regulation thus places the competitive onus on the QFs by requiring them to reduce their costs below those of alternative energy sources. In return, they are not subject to price, cost-of-service, or profit regulation.

The effect of PURPA

Considerable growth in the unregulated generation sector has resulted from PURPA. The aim of this initiative was to increase the number of supply source options for utilities, and to give all potential power producers a fair chance to compete. To this end, it has been responsible for the emergence of non-traditional independent power producers, as well as the growth of cogeneration facilities.

However, there have been problems in the implementation of the avoided-cost principle. Joskow (1989, p.170) argues that this is because:

> It is very difficult to calculate accurately the true avoided cost associated with a particular contractual relationship except in those circumstances in which the utility simply agrees to compensate the supplier based on the short-run operating and shortage costs avoided at the time of supply, a spot pricing system reflecting supply and demand conditions in real time.

Regulators initially underestimated the difficulties of determining the terms of contracts between buyers and sellers. The problem was exacerbated by the fact that the method of assessing avoided cost was left to individual states. An uneven application of the principle resulted. For example, California based avoided costs on oil prices, resulting in a flood of offers. Massachusetts introduced a market based system combined with bids for new plant to meet expected load, which has been taken up in several other states.

PURPA has promoted considerable growth in Non-utility generation (NUG). NUG accounted for 2 per cent of total US electricity generation in 1988, and is projected to reach 5 percent by 1997 (IEA 1989, p.573). While it represented a very small proportion of generation capacity in 1989, it represented a much larger fraction of expected additions to capacity. Further, a much larger proportion of NUG capacity was sold to local networks rather than directed into own-use operations after the passage of PURPA.

Current conditions and future prospects

The disruptions faced by the regulated sector since the 1970s were the result of supply side disturbances to both the ESI and the broader economy. It became clear that the regulatory framework was unable to respond quickly to changing market circumstances, and therefore impeded the efficient operation of the industry. These problems resulted from the overly simple focus of the regulatory regime on price and entry conditions. The industry's regulation also eschewed consideration of how electricity prices were structured, the efficiency of production decisions, and the desirable level of cooperation, coordination and horizontal mergers.

Price regulation forced private utilities to undertake investments in generating plant which may not have been the most economic option. For example, utilities might install less capital intensive generating plant with higher operating costs rather than large base load plants with lower operating costs to meet future requirements.

The FERC's regulatory initiatives, including PURPA, helped to create more competition in wholesale electricity markets. The competitive element has been enhanced by the implementation of the avoided cost principle. However, the issue of common carriage remains to be addressed. To this end, the FERC has taken begun introducing common carriage conditions to merger and rate cases.

These developments have seen the role of the FERC evolve from a rate-setter to something more akin to a trade practices body - ensuring the maintenance of fair competition. This change implicitly recognises the failure of the regulatory process to promote an efficient electricity industry.

Some commentators have argued that the infusion of greater competition into electricity markets will not eliminate the need for substantial government intervention.

Monopoly elements will continue to exist and these will require a strong planning and co-ordination role to be played by FERC. The transactions between participants in wholesale markets which are likely to require regulatory supervision include:

- brokerage systems under which non-utility producers supply electricity to utilities;
- contracts designed to ensure that 'merit' order despatch arrangements are maintained;
- treatment of costs in utility's accounts; and,
- treatment of reliability issues in contracts, given the different levels of reliability which will be associated with alternative suppliers.

Natural gas

Background

Natural gas production, transmission and distribution in the United States is privately owned and operated. The industry is subject to extensive regulation at both the state and federal level. Most pipeline companies buy their gas directly from producers, and resell the gas to end-users or unaffiliated distribution companies. In recent times, some pipelines have taken on common carriage status, with producers selling gas directly to end-users or distributors.

Natural gas and oil producers explore for, produce and sell gas to end-users and pipeline companies. Gas is obtained from Texas, Louisiana, Oklahoma, Appalachia and Alaska within the United States, and also from Mexico and Canada. The United States is a net importer of gas, with imports constituting over 5 per cent of total gas supplied in 1987. Three new pipelines are to be built to service the northeastern United States. Two pipelines will bring in Canadian natural gas, with the other transporting gas from the Midwest. The new pipelines should be authorised by the FERC and operable by the end of 1992. Increasing gas supply to this region is seen as urgent to facilitate the generation of electricity (IEA 1989).

Interstate carriers of gas enjoy considerable market power. O'Neill (1985) examined nearly 1500 gas distributors, and found that 90 per cent of them faced two gas pipeline suppliers who controlled 100 per cent of the market. Usually one firm was the dominant supplier, with the other firm having only 10-15 per cent market share.

Historical operation of the regulatory system

The Natural Gas Act

Federal Government regulation of the natural gas industry began in 1938 with the Natural Gas Act (NGA). This Act required the FERC to set rates of return and control the tariffs of interstate pipelines, and to control unfair entry. In 1954, the Supreme Court ruled that the FERC's authority should be extended to independent gas producers who sold gas to pipelines engaged in interstate commerce.

The FERC is empowered to enforce provisions which amount to de facto entry and exit restrictions on operators. Before a pipeline can commence construction and operation it must obtain a certificate of "public convenience and necessity" from the FERC. This effectively confers on the pipeline a statutory right to sell gas, and on its customers a statutory claim to both a portion of the reserves under contract to the pipeline, and a portion of pipeline's capacity. The NGA also stipulates that the FERC has jurisdiction over the termination of these statutory rights. A pipeline is obligated to provide service even if the operative contract has expired, unless approval for "abandonment" has been granted by the FERC. Similar service obligations have been imposed on gas producers, although gas that is freed of price controls is in general also released from these abandonment requirements.

The NGA granted interstate gas pipeline companies "private carrier" status, allowing them to purchase and resell the gas they ship. Under the NGA, pipelines can offer "contract carriage" service, where they are paid a fee to ship gas sold by producers directly to distributors or wholesale end-users. However, they cannot be compelled to provide such services. The FERC must approve all contract carriage arrangements.

The NGA also introduced a number of service obligations to wellhead contracts. Wellhead contracts specify the prices and quantities of gas a producer will deliver to a pipeline over a particular period of time. Most contracts have terms of 15 to 20 years, although newly signed contracts have shorter terms.[6] According to Broadman (1986), the NGA provisions include:

price escalation clauses, which either specify a fixed schedule of price changes over time or set the price of gas equal to some multiple of the price of an alternative fuel;

most-favoured nation clauses, which tie the contract price to the highest price (or average of the highest two or three prices) paid in other transactions within the same field or in nearby fields;

6 Within the last few years many new contracts have had three to five year terms. Some gas is now being sold on a "spot" market basis. Also, vertical integration has increased significantly in the past few years, particularly between producers and pipelines.

market out clauses which allow the pipeline either to reduce unilaterally the price it must pay or to renegotiate the contract if it cannot resell the gas at the contracted price;

deregulation clauses, which stipulate that if the gas under contract is subject to government price ceilings and such ceilings are removed, the price will be determined automatically by whichever of the aforementioned price provisions are specified in the contract.

Apart from the NGA legislation, intrastate pipelines were subject to state regulation which had been in operation long before Federal Government involvement in the industry. Price ceilings for interstate gas were based on historical production costs and, as such, were usually well below the price of less regulated intrastate gas.

Tendency to de facto vertical integration

Regulatory policy in the US has traditionally discouraged vertical integration. Vertical integration abuses by public utility holding companies were one of the reasons for the passage of the *Public Utility Holding Company Act* in 1935 (Cramer 1989). However, there have been strong incentives for vertical integration in the natural gas industry. Investment in the industry is of a long-term nature, and involves high sunk costs associated with the location specific capital. These costs encourage participants to allocate risk effectively and minimise the scope for 'opportunistic behavior' by other parties. Long-term contracts binding buyers to sellers, and which restricted competition, developed in place of vertical integration. The two major contract types were:

wellhead contracts between pipelines and gas producers which included take-or-pay requirements; and

city-gate contracts between pipelines and distributors which included purchased gas automatic adjustment clauses, minimum bill obligations and the mandate to serve as the supplier of last resort.

Take-or-pay contract provisions require pipelines to pay for as much as 90 per cent of their contracted gas deliverability, even if the pipeline chose not to take the gas because of slack demand. According to Cramer (1989, p.138), producers holding such contracts could control their income by changing deliverability in the field, so that:

> The consequence of this institutional arrangement was that there was no economic incentive for the producers to integrate towards the transportation segment of the industry.

The effect on pipeline operators was to require them to pay for a high percentage of their maximum gas take, regardless of demand conditions. They responded by imposing minimum bill requirements on their contract distributors. These were an upstream version of the take-or-pay provision, and ensured the pipeline company a minimum income. Purchased gas adjustment clauses further strengthened linkages between pipelines and distributors.

These allowed a pipeline to respond to inflationary field prices by boosting rates to end users automatically, without regulatory review. Various other provisions, such as sole supplier and territorial-restriction clauses, also insulated pipeline-distributor transactions from competitive pressure. This progression of restrictive contracts from the wellhead to final consumer:

> ... ensured the transfer of risk to the downstream buyers ... the shifting and incidence of risk, is nothing more than a variation or form of cross subsidy. The concept of restraining any buyer and seller long-term is the antithesis of competition (Cramer 1989, p.138).

Broadman (1986) argued that wellhead and city gate contracts had the potential to create market rigidities. These contracts are usually long term, with price and quantity adjustments specified in the contract. However, given that demand is uncertain and subject to a great deal of fluctuation (due to changes in weather or economic activity), not all possible contingencies can be taken into account.

The Natural Gas Policy Act

The full implications of these contractual obligations were only realised when demand conditions altered significantly in the 1970s. The industry experienced strong supply growth in the period up until the mid-1960s. However, from 1967 consumption of natural gas exceeded additions to proven reserves. In the mid-1970s gas shortages developed. Curtailments of gas were introduced to ration the limited gas supplies available in interstate markets. These shortages had developed because the FERC had set interstate gas prices below those in the more lightly regulated intrastate markets.

In response to the shortage of gas, Congress enacted the *Natural Gas Policy Act* (NGPA) in 1978 to bring both markets under the same regulatory umbrella. This legislation extended Federal jurisdiction to intrastate gas and provided for the:

- immediate deregulation of high-cost gas prices[7];
- phased deregulation for the price of new gas (other than high cost gas); and
- continuation of cost of service price ceilings for old gas. Old gas is that which was dedicated to interstate commerce before the NGPA was introduced, while new gas is defined as that developed after April 20 1979.

The NGPA achieved the intended effect of higher field prices. This, in turn, provided incentive for increases in interstate gas supplies, and therefore reduced the prospect of a recurrence of the serious gas shortages of the 1970s. But it soon became evident that a number of unintended effects were also occurring. Severe distortions in the gas market began to develop from 1982. These problems occurred because of the inability of negotiated contracts to deal with changing external conditions.

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7 High-cost gas is supplied 'from wells drilled after February 1977 to at least 15,000 feet and from geopressured brine, coal seams, and Devonian shale' (Broadman 1986, p.497).

Shortly after the introduction of the NGPA, the second oil shock of the 1970s hit the gas industry. This led to further strengthening of the already rigid long-term contracts that pervaded the industry. Where possible, higher prices were negotiated. Negotiations that were limited by price ceilings, introduced price-escalator clauses along with increased take-or-pay obligations and minimum bill provisions. Such agreements were reached under the presumption that the upward pressure on gas prices would continue.

These contracts were not designed to cope with downward pressure on prices. This became evident in the early 1980s when, despite a fall in the price of alternative fuels, the price of gas continued to rise. Many consumers, particularly large users, sought alternative fuels. Attempts to sell gas competitively at lower prices violated contract conditions. Moreover, federal and state regulations prohibiting price discrimination prevented some pipelines and distribution companies attracting large users back to gas through offers of reduced rates.

Regional price disparities

The NGPA created twenty four categories of field price ceilings for wellhead gas. Differences in the gas category 'portfolios' of producers led to price differentials across pipelines. Some pipelines were endowed with large 'cushions' of cheap old gas. As observed by Broadman (1987):

> Because pipelines are subject (under the NGA) to traditional cost-of-service regulation and price their gas sales on the basis of average rather than marginal gas acquisition costs, the extent to which a pipeline is willing to contract for relatively expensive gas is determined by, among other things, the size of the "old" gas "cushion" it enjoys in computing average cost: the larger the "cushion", the higher the price bid for new supplies.

Further, pipelines were generally allowed to pass costs onto end-consumers under FERC regulation. Many distribution companies are also tied to particular pipelines, so that these cross-pipeline gas cost differences are reflected in downstream markets. Consequently, high prices were concentrated in particular regions and low prices in others.

Consequently, gas supplies were allocated inefficiently because willingness to pay was not equated across customers. It is probable that differences in gas costs would not have been sustained in downstream markets if there was greater competition in interpipeline gas sales and purchases. But such competition was prevented by a number of factors, including:

- the exclusivity of some wellhead and city gate contracts;
- the NGA's certification and abandonment requirements, and the statutory service obligations imposed on pipelines which restricted the ability of new entrants to take advantage of these interregional price disparities; and
- the subordination of "off-system sales", by which pipelines agree to sell to one another on a transitory basis, to the demands of the seller's regular, 'on-system' customers.

> Off-system sales were also prevented by the sole-supplier and territorial restriction city-gate contracts imposed on distributors.

Off-system sales were important in reducing the imbalances between the glutted intrastate and the thin interstate markets in the 1970s. Potentially they could have performed a similar function in the context of these interregional disparities.

Barriers to interpipeline competition accentuated the artificial price disparities which existed across regions. Consequently, they may excluded customers from the market who were willing to purchase gas at prices that would cover costs. They also limited the responsiveness of pipelines to shifts in demand. Similarly, pipelines that had high proportions of expensive gas were not forced out of the market. This was due to the contracts that obligated distributors to buy gas from such pipelines, and also the regulatory constraints that prevented low cost pipelines from expanding their market (Broadman 1989).

Current conditions and future prospects

Clearly, the complexity of contractual arrangements and the plethora of regulatory provisions acted to impede the functioning of the market during this period. In response to these problems, various regulatory reforms have been introduced.

Recent FERC initiatives

The FERC introduced a number of reforms in the mid-1980s. One of the more notable of these was the prohibition of minimum bill provisions in 1984. The FERC ruled that these could no longer be used to recover variable costs not actually incurred by the supplying pipeline. This reform promoted competition for gas supplies by distribution companies and smaller pipelines. At the same time the FERC did not relax the pipelines' obligation to supply downstream customers. Consequently, numerous litigation cases were brought against downstream pipelines and reticulation companies which had curtailed their contracted demand. In response, pipelines unable to gain satisfactory redress under the antitrust laws began to merge with upstream producers in the hope of forcing downstream customers into a compromise (Cramer 1989).

A further reform was the introduction of voluntary contract carrier for interstate gas. This program was designed to separate interstate pipelines' transportation services from their brokerage and storage activities. Participating companies were rewarded with light-handed regulation. Under the scheme, customers with an agreement to buy gas owned by the pipeline (private carriage) could fill such requirements with their own gas (contract carriage). Alternatively, large gas customers could by-pass the reticulation utility and purchase gas directly from a gas producer or pipeline. Other concessions included options to buy out onerous take-or-pay contracts with producers and the expedition of the approval process for construction or abandonment of pipelines (Broadman 1986).

As a result of this initiative, a spot market, and more recently a futures market, for gas has developed. The percentage of gas delivered to the market by third parties as a increased from 3 per cent in 1982 to 56 per cent in 1987 (IEA 1989, p.577).

The Reagan administration argued for the deregulation of all gas prices in the mid-1980s, but was opposed by congressional and public factions which succeeded in preventing this action. However, with the *Natural Gas Decontrol Act* (NGDA) of 1989 the objective of wellhead price deregulation was achieved. This Act allowed for the removal of remaining wellhead price controls by the end of 1992.

The need for a more cohesive reform agenda

The problems experienced by the US gas industry illustrate the pitfalls which can be involved in regulatory supervision of industries experiencing changing economic conditions. From the preceding analysis it is evident that the market rigidities introduced by the contractual and institutional practices in the industry are mutually reinforcing. Problems originating at the wellhead were passed down the system, and eventually to consumers. Similarly, demand side disruptions worked there way up the system to producers. It is because of this interlinking of constraints that the industry had difficulty responding to changing market conditions.

An important lesson emerging from the US experience is that policies need to be developed in light of all the problems pervading the industry. Regulators must avoid dealing with certain sections of the industry in isolation. This happened in the case of minimum bill reform, which was banned in 1985, while at the same time distributors were left with an obligation to serve, which they were sometimes unable to fill. It was only with the more encompassing NGDA that the full extent of the industry's problems were addressed.

United Kingdom

Electricity

Background

The UK ESI is approaching the completion of a major reform program that has made it perhaps the most market oriented electricity system in the world. The reform of this industry has particular relevance for Australia in view of the high degree of integration and public sector control prior to reforms.

In 1988-89, the UK ESI employed 47 201 staff and had a declared net generating capacity of 55 123 MW, making it approximately twice the size of the Australian ESI.

Coal is the predominant generating fuel, constituting 71 per cent of total fuel inputs in 1987. Nuclear energy is the other major input into electricity production, amounting to 17.7 per cent of inputs in 1987. In the same year, oil and hydro-power constituted 8.8 per cent and 2 per cent, respectively. At present, only small amounts of gas are used for electricity generation.

The national grid is interconnected with both the Scottish and French electricity systems. The Channel link with France has a full operating capacity of 2000 MW. Net imports in 1987-88 amounted to 5 per cent of supplies.

A brief history of the industry

The UK electricity industry was nationalised by the 1947 Electricity Act, which established the Central Electricity Authority (CEA) to generate and supply electricity. It also created fourteen Area Boards responsible for the distribution of electricity in their designated regions. As a result of the 1956 Herbet Inquiry, the Central Electricity Generating Board (CEGB) was created in place of the CEA.

Performance of the CEGB

A number of reports during the late 1960s and early 1970s drew attention to the poor performance of the CEGB.[8] In 1981, both the Select Committee on Energy[9] and the Monopolies and Mergers Commission (MMC) were also critical. The Select Committee examined the problems of low

8 These included: National Board for Prices and Incomes (1968), Committee of Inquiry (1969), National Economic Development Office (NEDO) (1970), NEDO (1976), Plowden Committee (1976), Price Commission (1979).

9 The Government's Statement on the New Nuclear Power Program, Select Committee on Energy, Volume 1, Session 1980/81, HC 114-1, HMSO, 1981.

productivity and industrial conflict in the building of the Isle of Grain oil-fired power station, which was over budget and four years behind schedule. The Committee concluded that:

> ... the CEGB must, in our view, be blamed for their reluctance and inability for so long to assert firm management and to promote and increase productivity (Henney 1987, p.14).

At the same time, the MMC found that five conventionally fired stations then under construction were expected to be delayed from two to three years, and to overrun costs (in real terms) by 19 per cent. Similarly, the MMC found that the average overrun costs of CEGB's advanced gas-cooled reactor stations was just over 100 per cent in real terms. Rather than the planned completion date of six years, the revised time was in the order of 15 years.

Excess capacity was also a feature of the CEGB. The MMC contended that the CEGB's forecasts of demand consistently over-stated the need for new plant, resulting in unnecessary construction programs. The reserve plant margin peaked at 42 per cent in 1975, almost double operational requirements, and would have reached 60 per cent if plant had been commissioned on time. According to the MMC (1988, p.15):

> ... a large program of investment in nuclear power stations is proposed on the basis of investment appraisals which are seriously defective and liable to mislead. We conclude that the Board's course of conduct in this regard operates against the public interest.

The MMC further concluded that, the CEGB had 'juggled' the figures so as to ensure that nuclear power stations would be built. This was partially in response to pressure applied by the Atomic Energy Authority, consortiums of private companies wanting to build nuclear power stations, and by the Government wishing to counter the power of the National Union of Mineworkers.

Another area of concern was the CEGB's sourcing of fuel inputs, particularly coal. The CEGB did not appear to contract with British Coal on a strictly commercial basis. The CEGB had committed itself to buying 95 per cent of its coal at an average price of 43 pounds per tonne when the spot market price was about 23-25 pounds per tonne (Henney 1987).

The CEGB is not the only body within the electricity industry that was criticised for its poor performance. The Herbet Committee asserted that the Area Boards undercosted retailing activities in order to disguise their poor performance. Both the Office of Fair Trading (1982) and the MMC (1983) indicated that the London Electricity Board had lost money on electricity retailing for a ten year period. This inefficiency was in part attributable to overemployment of labour, and paying above retail wage levels (Henney 1987).

The privatisation scheme

In 1988, the Government announced its intent to privatise the ESI. In the interests of promoting competition in the industry, it was decided to separate the functions of generation, transmission and distribution. This was in part the result of the experience of the Gas Industry privatisation (see the following section).

Industry reforms

The UK Department of Energy (1988) released a White Paper containing details of Government proposals for privatisation of the electricity supply industry in England. The proposals in this paper were the basis of later debate, but ultimately shaped actual industry reforms. New operating arrangements for the industry were progressively introduced up until 1 April 1990, when the new regime became operational.

The ESI's restructuring has involved the division of the CEGB's generating plants into three operating companies. One of these companies, the Nuclear Electric Company (NEC), comprises all of the CEGB's nuclear power stations as well as some hydro and gas turbine stations, for operational safety purposes. It is intended that this company will remain in the public sector. The remainder of the CEGB's generating assets have been divided between two companies, the National Power Company (NPC) and the Power Gen Company, which respectively own approximately 51 per cent and 32 per cent of CEGB's former capacity. These companies were floated in February 1991.

The CEGB's high voltage transmission grid and pumped storage power stations have come under the control of the newly created National Grid Company (NGC). This company is owned by the distributors, but is heavily regulated, particularly with respect to access for current and future generators.

The twelve former Electricity Area Boards have become Public Electricity Supply Companies (PECs). Share releases were over-subscribed when these companies were floated in 1990.

Under the new arrangements, the ESIs of England, Wales and Scotland are regulated by the Director General of Electricity Supply (DGES), who heads the Office of Electricity Regulation (OFFER), in place of the former Electricity Council.

The regulatory environment differs for particular activities depending on the potential for competition. Those activities regarded as natural monopolies are separately regulated. This includes the distribution companies' network business and the NGC's transmission business, both of which will be subject to a CPI-X formula.

Distribution companies' supply functions, including power purchase contracts, are presently subject to regulation, but this will be phased out as competition develops. The remaining generation and supply (excluding distribution companies) activities are not subject to regulation.

Regulation also does not apply to those customers who take more than 10 MW of electricity since these customers have the option of negotiating supply with either the distribution authorities or with a generating company (Putnam, Hayes and Bartlett 1989).

Under the new regime, the industry is controlled by a system of licences granted by the Department of Energy, and administered by the DGES. Such licences include:

- "first tier" Public Electricity Supply Licences for the 12 distribution companies to supply tariff and contract customers in their existing areas;
- a Transmission Licence for the NGC;
- Electricity Generation Licences for those generators producing electricity for supply to others from at least one station with a capacity of 50 MW or more: and
- Licences to Supply Premises, or "second tier" licences, for those generators supplying customers directly, using their own lines or those of the public electricity suppliers (IEA 1988).

Of primary importance to the new regulatory system is the competitive impetus provided by the privatised distribution authorities. Through the terms of the first tier licences, the PECs will retain responsibility for their regional distribution networks, but under the new arrangements there is no longer an obligation to supply. But the distributors do have an obligation to offer supply to customers within their area - at a price considered economic by the distributor. However, the regional monopoly system is to be removed. This will allow customers to seek quotes from alternative suppliers, since they do not have to accept the bid of their local company. The removal of the exclusive franchise system is to be phased in over the period until 1998, with only large customers initially being able to purchase electricity from alternative distribution companies.

Under the new regulations, the PECs are required to provide secure supplies of electricity, to set non-discriminatory prices for the use of their distribution and transmission systems and to purchase electricity from the least cost source. Fair wheeling charges must be made where sales across franchise boundaries occur.

The PECs are free to own and operate generating stations, but only to a limit (probably 15 per cent of the electricity they supply). Where such stations are owned, they must be kept financially separate from distribution activities. Independent generators may contract to supply customers and are entitled by regulation to have open access to PECs' networks at prices no less favorable than those the distribution company charges itself.

The second tier licences, to supply premises, enables companies other than the 12 PECs - such as the French and Scottish utilities, and energy brokers - to supply electricity to customers not covered by the distribution franchises. Such companies can use the national grid and the distribution network if necessary, with payment of appropriate wheeling charges.

At least one of the twelve distribution companies has applied for a second tier licence (Warburg 1990).

The pooling and settlements system

It is in the key area of accommodating system coordination with competition in generation that the new UK model is of particular interest. The electricity pooling system provides a framework for the wholesale buying and selling of electricity. Generators sell their output to the pool, and distributors, as well as large customers with direct pool access, buy power from the pool. The settlement system controls the flow of funds between trading players, and is administered by the NGC.

Generators offer electricity to the pooling system a day in advance for each of 48 half hour periods. These rates reflect plant operation costs. The NGC performs the coordination role of ranking each generating plant's bid in order of increasing price, and decides the despatch order for the plants in line with this. The 'system marginal price' reflects the cost of the most expensive incremental unit in operation at any given time. The NGC also considers other factors such as system stability and transmission capacity constraints when deciding despatch order.

The settlement system seeks to price electricity at cost, and create incentives to minimise the probability of blackouts. To this end, there are three major components in the pricing structure faced by generators (but not purchasers who pay only one price). These include:

- System Marginal Price (SMP) payment, equal to the bid price of last generator despatched, and therefore the marginal producer. The SMP is paid to all operating generators on a unit basis for all production in the period;
- Capacity Element payment, structured to become significant when there is an increasing chance of blackout, and hence provide incentive for the prevention of this situation. It is paid to all generators on a unit basis for production during the period; and
- Other Operating Expense payment, made to specific operators that provide necessary system functions such as stand-by plant capacity and stability.

All pool customers purchase power from the pool on a spot basis. Contract customer settle any differences between the spot payments made and their contract rates with the generator directly.

Assessment of the privatisation scheme

Initial indications are that the ESI's privatisation has attracted new entrants to generation. For instance, ICI and an American utility are constructing an 850 MW combined-cycle plant in the north-east of England. Additionally, of the 12 000 to 15 000 MW of new capacity currently planned, some 5 000 MW is own generation or cogeneration plant.

This is in part due to the more open gas pricing policies since that industry's restructuring, and the access allowed to overseas gas supplies. As a result, less efficient coal based plant is being phased out.

Formulation of the privatisation plan for the electricity supply industry took place against a background of increasing dissatisfaction with previous privatisation programs. From the privatisation of the gas industry it was evident that the method by which industries are privatised is an important determinant of the potential for future competition. Consequently, more thought was given to the promotion of competition in the ESI's privatisation.

Competitive elements

The principal question for the UK reforms is whether the new ownership and structural arrangements will stimulate competition and therefore increase economic efficiency, thus offsetting any efficiency losses which may arise from a more decentralised industry structure. Through its coordination and control operations, the NGC enables the new system to have some of the same operational advantages of the nationalised system, ensuring that output and demand are matched and minimising generation costs by continuing to bring on plants in merit order.

The new ownership arrangements give the PECs more incentive to promote competition in generation. It is likely that they will attempt to minimise the costs of the electricity they buy. This could involve contracting out for power station capacity on the basis of competitive tenders. Generating companies will have greater incentive to build and operate plant efficiently in order to win these contracts.

The PECs will also have a wider choice of power sources. For instance they will be able to secure electricity supplies from:

- the three new generating companies;
- the existing private producers (co-generators);
- their own generating activities;
- joint ventures; or
- Scotland and/or France.

Additionally, the PECs will be subject to some degree of competitive pressure themselves. Adjacent companies could be competing to supply large users near their common borders. These companies would also be able to buy direct from generators, thus effectively by-passing the distribution system.

For those parts of the industry which do not appear to be highly contestable, a regulatory regime based on price controls has been established to safeguard the interests of consumers.

While the current privatisation proposal appears to be better equipped to promote a competitive industry, there still remains some uncertainty about its ultimate impact on the efficiency of the industry.

Criticisms of the reforms

In a paper on 'Competition in Electricity?', Robinson (1988) has questioned whether competition would arise in generation. She claims that the newly established generating companies will have a strong incentive to collude and restrict entry into the industry. Since the market demand for electricity is highly price inelastic, Robinson argues that the generating companies would be better off restricting output and raising prices (ie acting as a monopolist).

Further, the three companies will be well placed to compete against any potential entrant into the market. Each company will have available to it a mix of plant which potential entrants must compete against with only one power station. They will also be able to cross-subsidise when quoting for power supplies from existing stations.

Similarly Henny (1987) contends that nine or ten generating companies, each limited to no more than 20 per cent of the market, would be required to ensure a competitive environment.

Ownership of the NGC

With respect to the ownership of the NGC, and consequently of its associated coordination and control attributes, the following rationale was put forward in the 1988 White Paper (p.6) for the current system:

> ... the grid has to retain a central role in planning and directing the use of power stations to minimise cost and to ensure that the system does not fail. It follows from this that, if the CEGB or any other generating company owned the grid, it would inevitably have to direct the use of all the major power stations on the system. To a large extent, it would have to determine how much competing generation was allowed access to the system and how its competitors' stations were run. The Government does not believe that it would be fair to put any generating company in such a position after privatisation, where it effectively owns the means of transmission and controls its competitors power stations.

The current regulation seems to have gone to the other extreme in granting distributors control over the transmission network. The new regime takes this possibility into account by limiting the distributors' powers over the NGC, and by regulating access to the transmission and distribution network. But this arrangement places heavy reliance on the ability of the regulator to ensure open access to the transmission and distribution systems.

Rather than attempt to deter the erection of entry barriers by regulation, Robinson (1988) suggests that this could alternatively be achieved by not permitting distributors to generate a proportion of their own requirements.

This proposal would avoid the need for regulations designed to preclude or forestall the creation of local monopolies which may not necessarily work.

Price regulation

The price regulation of potential natural monopolies also raises important questions. Determination of the 'X' factor is inherently a matter of judgement. It is also a matter of negotiation between the company and the regulator, with the company deploying information to justify the smallest possible X'.

Whereas British Gas has considerable scope to alter the X factor due to its monopoly position in gas supply, the distribution companies will have less scope for manipulating it since there will be 12 companies undertaking the same activity, albeit with different geographic and demographic profiles, thus providing the regulator with performance comparisons with which to calculate X.

Other issues

Due to the recent timing of the UK ESI reforms, a number of questions remain unanswered. Some of these were highlighted in the New South Wales Government's submission. For example:

- will capacity element payments will be sufficient to encourage the right type and timing of new generation capacity;
- will generators be able to use oligopolistic behavior to manipulate the market;
- will electricity prices on average be reduced;
- will the cost of the regulatory controls be so excessive as to outweigh the possible benefits from the changes;
- will the transmission charges established be fair to all generators; and
- will the coordination activities of the NGS approach the technical efficiency achieved in centrally coordinated unitary systems.

Natural gas

Background

The United Kingdom's gas industry has recently experienced considerable growth. In 1973, gas constituted only 11.6 per cent of primary energy requirements, but this had increased to 23.8 per cent by 1987. This rapid growth followed the discovery of natural gas in the North Sea, which enabled it to be supplied to British consumers in place of the extensively reticulated coal-based town gas.

In 1988, indigenous gas production accounted for 79 per cent of United Kingdom demand. The remainder was met by imports from Norway, with some additional liquid natural gas (LNG) supplies from Algeria (0.5 per cent of total supply in 1988). At present, there are no exports of natural gas from the UK. It is expected that supplies of gas from already approved fields in the North Sea will be sufficient to meet demand until the mid 1990s. The Government sees further potential for the development of new fields, with further technological advances permitting the exploitation of smaller deposits.

Exploration for, and extraction of, natural gas in the North Sea, together with transmission to the beachhead, is mostly carried out by oil companies operating on the United Kingdom Continental Shelf. British Gas (BG) has the largest single share of proven and provable gas in this area, amounting to about 15 per cent of the total supply. Natural gas enters the national transmission system at several coastal terminals. After treatment and measurement, the gas is carried at high pressure to over 100 regional off-take points where it passes into the regional transmission system which conveys it to the main centres of demand, and finally to customers via local distribution systems.

Historical operation of the regulatory framework

The 1948 industry nationalisation

In 1945, the Government commissioned the Heyworth Committee to investigate the gas industry. The subsequent report argued that nationalisation of the gas industry would enable the attainment of various scale economies. It also contended that it was not necessary to develop a national grid to realise available economies of scale. In response, the Gas Act of 1948 amalgamated Britain's 1046 gas companies and undertakings into twelve Area Boards, each board organised as a separate statutory authority responsible for all aspects of gas manufacture and supply in their region.

Large reserves of natural gas were discovered in the North Sea from the mid 1960s. This prompted the construction of a national high pressure gas transmission system. Under the *Gas Act 1972*, the British Gas Corporation (BGC) was established, and took over the operations of the twelve Area Boards. The Act also gave the BGC power to search for gas and oil. Until 1982, the BGC also exercised monopsony powers in respect of purchases of North Sea gas.

BGC was able to place downward pressure on the prices producers received for their gas supplies.

A number of studies indicated that the average contract price was typically below marginal opportunity costs between 1973 and 1987.[10] It is likely that much of the penetration of gas into the energy market between 1975 and 1985 was attributed to these 'suboptimal pricing policies' (Vickers and Yarrow 1988, p.257).

The Oil and Gas (Enterprise) Act was introduced in 1982 with the intention of liberalising the gas market by establishing common carriage provisions which, in principle, allowed other suppliers to transmit their gas through BGC's pipeline network. However, the legislation was ineffective in promoting competition, because:

- the Act excluded new suppliers from the residential market, which was the largest market segment;
- larger customers were supplied on a contract basis, for which the terms and conditions were confidential. As a result, BGC could engage in predatory pricing to deter new entrants;
- BGC was able to offer greater security of supply than potential rivals, through its large integrated network ;
- new entrants had to negotiate with BGC for the use of the pipeline network, thus providing scope for BGC to impede entry by charging excessively high prices for the use of its facilities; and
- BGC obtained its supply under long-term contracts from established gas reserves in the North Sea. A rival would have to obtain gas from newly developed fields. The unit costs of obtaining gas from new fields would be more expensive than BGC's purchase costs (Vickers and Yarrow 1988).

The 1986 gas industry privatisation

In response to these problems, and as part of the British Government's privatisation drive, it was announced by the Government in May 1985 that the industry would be privatised. The *Gas Act 1986* transferred the business of BGC to British Gas (BG), and established a framework of regulation for the industry. All shares in BG were sold in December 1986.

Many of the statutory rights and obligations which had previously applied to BGC were incorporated, with some modification, into the new framework. The Act provided for the appointment of a Director General of Gas Supply (DGGS) responsible for operating and enforcing the regulatory regime for the supply of gas. The DGGS is appointed by the Secretary of State for Energy and heads the Office of Gas Supply (Ofgas); a supervisory body which monitors the performance of BG.

Other provisions of the Act:

10 The results of these studies are summarised in Vickers and Yarrow 1988, p.257.

- abolished BG's monopoly over the supply of gas, and established a system whereby the Secretary of State for Energy may authorise any person to supply gas through pipes to any designated area;
- extended provisions for third party use of pipelines owned by public gas suppliers. It was envisaged that the third party would negotiate with BG. However, if such negotiations were not successful, the third party could apply to the DGGS for access to the gas system;
- divided the market into contract and tariff segments. Customers that consumed less than 2.5 TJ a year were charged according to a published tariff, which was calculated in accordance with the formula set out in BG's Authorisation. For supplies in excess of this amount, BG makes special contracts with individual customers; and
- created the Gas Consumers' Council (GCC) whose function was to investigate complaints from both tariff and contract customers.

In view of the market power granted to BG by the Gas Act, an accompanying authorisation was made to establish some regulatory controls on its operations. This authorisation included specification of accounting procedures, price controls, common carriage and other provisions.

Accounting procedures

Under the Authorisation, BG is required to prepare separate accounts for its gas supply business. This excludes activities such as appliance trading, installation, contracting activities, exploration and production, and provision of consultancy services. However, the highly aggregated nature of the information requirements will make the monitoring task of Ofgas difficult.

Price controls

The Authorisation sets out a formula to determine the average level of prices charged to tariff customers in the period from 1986 to 1992. The formula divides the maximum price of gas into two components: the gas component, which is the average cost of obtaining gas; and the non-gas component, which is a charge per energy. Changes in this second component are limited to the percentage change in the retail price index less two percentage points. This component places a limit on the ability of BG to increase prices. Thus, BG can only increase profits by reducing non-gas unit costs by more than two per cent per year during this period. For the period 1992-97, the 'X' factor has been increased to five per cent.

Since the formula links maximum prices in a given year to the retail price index and gas costs in the same year, BG must rely on forecasts of these variables. If the actual and estimated variables do not coincide, a correction factor allows under - or overcharging in a given year to be corrected subsequently. The correction factor ensures that BG does not benefit from forecasting errors, and provides a disincentive to deliberate manipulation of forecasts.

Contract prices are unregulated, other than provisions for the publication of maximum payable prices and general contract policy by BG.

Common carriage

BG is required, after consulting the DGGS, to prepare a statement setting out general information for the guidance of persons wishing to negotiate with it for the conveyance of gas.

The authorisation also requires that BG prepare a statement concerning policies regarding the supply of gas to third party gas suppliers in the event that their supply of gas being temporarily interrupted. This provision ensures security of supply for the customers of new suppliers, which is a potential barrier to entry for such suppliers.

Other provisions

The Authorisation also details a variety of other matters including the provision of information to the DGGS and to the Gas Consumer's Council, provision of emergency service, codes of practice for gas suppliers, payments of bills and provision of services to the elderly and disabled.

Assessment of the privatisation scheme

The gas industry privatisation program has been subject to considerable criticism. The major criticism is that the Government traded a public monopoly for a private one, and in so doing, failing to realise the competitive benefits that the privatisation was intended to capture.

Price formula

The pricing formula preserved the existing practices of setting prices on the basis of average costs rather than marginal costs. Average price increases can mask substantial differences between its component elements.

Additionally, this arrangement may not accurately reflect locational differences in costs of supply, with the consequent implication of regional cross-subsidies. Similarly, the formula makes no allowances for differences in the cost of supply over time, for example between peak and off-peak pricing. The limited accounting requirements imposed on BG make the task of Ofgas in overseeing BG's price fixing decisions more difficult.

The price formula also fails to place any control over gas costs incurred by BG. It implicitly assumes that BG is a price taker for North Sea gas. But considering the legislative requirement that gas from the UKCS must be landed in Britain, this is clearly not the case.

Thus, BG may be able to acquire gas at below marginal opportunity costs. Two consequences follow from this: excessive consumption of gas is encouraged, and BG realises a considerable advantage over potential entrants in gas supply.

Competition

There has been little effort to promote active competition in the supply of gas. BG's Authorisation effectively blocks entry into the domestic-users market. In the industrial and commercial users market, there remains a number of obstacles to the emergence of competition. These include:

- BG's access to low price gas from the Southern Basin fields, which means that average purchase costs will be lower than potential rivals who must rely on newly developed fields;
- since BG is not required to account separately for various parts of its business, it will be very difficult to determine whether it is engaging in predatory pricing; and
- control of the pipeline network affords BG a considerable strategic advantage over potential rivals. An entrant must negotiate with BG for conveyance of its supplies, and subsequently, provide the incumbent with vital information about commercial contracts, thus enabling BG to offer more favorable terms.

The Office of Gas Policy's paper, *Competition in Gas Supply*, forecast that only limited use would be made of the Gas Act's common carriage provision, because most available gas had already been contracted to British Gas. The development of new fields in the early 1990s, however, would increase the potential for competition in supply. The report also argued that there were potential profits for producers supplying gas directly to end users, but that these profits must be sufficient to offset risks associated with selling the gas to smaller users (MMC 1988).

Regulation

Apart from the fact that Ofgas has been granted limited regulatory powers, there is also concern surrounding the long-term development of regulatory policy. For example, there is incentive for BG to undertake strategic behavior as pricing reviews approach, by withholding information on cost-saving projects from the DGGS - resulting in a revised price formula with price ceilings which could easily be achieved.

Expectations that the rate of return will be taken into account when fixing regulated prices leads to incentives to cross subsidise. BG may be tempted to depress the overall rate of return by charging lower prices in the unregulated market in the hope of charging higher prices in the domestic market. This practice is effectively encouraged by not requiring BG to keep separate accounts for each market segment.

Industry performance since privatisation

Despite limited experience with the industry reforms to date, evidence suggests that efficiency is being impaired by the current arrangements. In a report on contract tariffs, the MMC found extensive discrimination by BG in the pricing and supply of gas to contract customers. This discrimination involved:

- setting higher charges for those users less well placed to take advantage of alternative fuels;
- setting prices based on the costs of alternatives sources of energy to each customer, thus effectively placing it in a position to undercut potential gas competitors; and
- refusing to supply lower cost gas on an interruptible basis to some customers.

The MMC (1988, p.1) concluded that:

> BG's failure to provide adequate information on the costs of common carriage, its ability to use information obtained when negotiating common carriage terms to identify potential customers of competing suppliers and the potential source of gas, and its position as a dominant purchaser of gas, may all be expected to operate against the public interest by deterring new entry into the market.

As a result of these findings, the MMC recommended that BG should be required to:

- publish a schedule of prices at which it is prepared to supply firm and interruptible gas customers;
- sell interruptible gas to any customer;
- publish further information on common carriage terms in sufficient detail to put a potential customer in a position to make a reasonable estimate of the charge that would be sought by BG; and
- contract initially for no more than 90 percent of any new gas field.

The objective of these recommendations seem to be to promote a more 'level playing field' for potential competitors. It could be expected that oil companies will have more incentive to sell gas direct from the North Sea to industrial and commercial customers. However, competition between BG and the oil companies may still not arise. According to one author, oil companies are reluctant to attempt to compete against BG since the company effectively decides the order in which new gas fields will be developed (Wilkinson 1988). Thus, keeping on the 'right' side of BG is important in ensuring the long-run profitability of the oil companies.

New Zealand

Electricity

Background

New Zealand has an installed generating capacity of 7182 MW, of which 65 per cent is hydroelectric, 28 per cent is steam (including 261 MW geothermal), and 7 per cent combustion turbine.

The system is characterised by a geographic imbalance of load and resources. The South Island contains approximately 65 per cent of installed hydro capacity, but only 25 per cent of the population. All thermal generating assets are located on the North Island. The two Islands are connected by a single 500 KV DC link, which in 1985 supplied some 25 per cent of the North Island's electricity requirements. This link's capacity is a constraint on energy transfer between the two electricity systems.

The two Islands' networks are coordinated independently, with a scheduled interchange through the DC link. Due to the variability in water flows in the South Island, their dependence on weather conditions and the low water storage capacity, the level of hydro power fluctuates considerably and is hard to forecast (Micheals 1989). The five largest consumers of electricity in New Zealand account for 25 per cent of electricity.

Historical operation of the regulatory system

The New Zealand electricity industry has been predominantly publicly owned. The *Water Power Act* of 1903 vested the Crown with the rights to use New Zealand's water resources for electricity generation, by which powers the Government began developing the rudiments of a national grid system. In 1946, a separate State Hydro-Electric Department was formed, which later became the Electricity Department (ED), with responsibility for electricity generation and transmission (Task Force 1989b).

In 1988, sixty one local suppliers were responsible for electricity distribution, including local municipal distribution authorities and regional Electricity Supply Authorities (ESAs). These authorities obtained their full electricity requirement from the ED, at a tariff set by the department. This tariff was set lower than required to fully recover costs. Consequently, high levels of electricity consumption were encouraged, which along with pressure from construction unions for continuous employment, led to excessive generation capacity relative to the system's load.

The *Commerce Act of 1975* established the Commerce Commission, with primary responsibility for trade practice issues. The Commerce Act of 1986 considerably updated and revised this legislation.

The Commission may respond to suits instituted by both the government and private plaintiffs, and may impose fines and institute price controls where necessary - although this has never happened.

The 1985 corporatisation program

In response to perceived institutional rigidities associated with many state-owned enterprises, the Lange government introduced reforms aimed at establishing business principles in the running of these organisations. To this end, the *State-Owned Enterprises Act* was passed in 1986. The Act provided that:

> The principle objective of every State Enterprise shall be to operate as a successful business and ... to be ... As profitable and efficient as comparable businesses that are not owned by the Crown (Michaels 1989, pp.76-77).

This Act included the proposal that the ED be corporatised structure. As a result, in April 1987, the Electricity Corporation of New Zealand Limited (Electricorp) was formed. The chairman of Electricorp (1987) has argued that,

> Effectively, the Act removes the organisation from day-to-day political involvement, and places it under the discipline of the Companies Act.

Statutory barriers to entry into the industry for competing bulk generating firms were removed. The new corporation was directed to transmit third party electricity to end users so as to facilitate the development of a competitive generation sector. Electricorp is permitted to enter negotiations with large industrial users directly, bypassing the local supply authorities.

The Corporation was divided into four separate divisions: Electricorp Production, Electricorp Marketing, Trans Power New Zealand Limited and Power Design Build Group Limited. Electricorp Production is responsible for operating power stations, which are predominantly hydro based, and which account for about 95 per cent of the country's total generation capacity. Electricorp Marketing is responsible for supplies to electricity retailers, predominantly electricity supply authorities and customers in four regions. It buys electricity from Electricorp Production and other generators. It enters into short and long term supply contracts, and also oversees the developing spot market in electricity. Trans Power New Zealand operates the high voltage national grid system. The Power Design Build Group is responsible for design and construction of electrical equipment for the domestic and international marketplace.

The Electricity Task Force and structural reform

Subsequent to the corporatisation of the ESI, the Government created an Energy Task Force in February 1988 to advise it on the question of optimal industry structure, and the regulatory environment appropriate for electricity generation, transmission and distribution. The Task Force (1989b) found that:

> ... significant progress is possible to reduce concerns about ECNZ's dominant market position.

The Task Force made several recommendations for the restructuring of the industry, many of which are currently being introduced. It concluded that there should be no large-scale break-up of Electricorp into multiple generating companies. Further, there should be further consideration of the costs and benefits of spinning off one or two competitive generating stations.

The Task Force recommended that vertical integration between distributors and generators should not be prohibited.

The Task Force also recommended that the transmission grid should be owned by a club of distributors and generators, constituted as a company under the Companies Act. The rules for club membership should specify club entry conditions and voting rights. There should be some government voting share retained. The recently created Trans Power Establishment Board is to implement the grid's separation by July 1 1991, and to report on the establishment of a wholesale electricity market.

All 51 ESAs are to be set up as companies with shareholding vested in trusts. Exclusive area franchises and the obligation to supply are to be removed, with the process complete by January 1993. Similarly to transmission, a transition agency, the Electricity Distribution Reform Unit, will monitor tariffs and the social impacts of the industry reforms.

In addition to these structural changes, a light-handed regulatory regime based on information disclosure is to be introduced. Chief aspects of this regime include:

- tariffs to consumers should show transmission and distribution costs to consumers separately from energy costs;
- the generation sector will be required to disclose prices, terms and conditions of supply; and
- the transmission grid will have to disclose costs, cost allocation policies, pricing policies and performance measures.

It is anticipated that price disclosure will facilitate new entry into generation and retailing, and that information disclosure generally will assist action under the Commerce Act against anti-competitive practices. Questions that remain to be answered include who should own the new distribution companies, the nature of the wholesale electricity market and various aspects of the operation of the new transmission club.

Transmission pricing

Actual transmission prices are anticipated to be finalised by 1 July 1991, when Trans Power will be separated from Electricorp. This will allow transmission contracts between Trans Power and grid users to take effect from 1 October 1991.

Trans Power's pricing is to take account of revenue requirements, efficiency, fairness and should be stable over time. Trans Power (1991, p.4) has argued that:

> These objectives are best achieved by a price structure which is not only based on the "user pays" principle, but one which also recognises that there are limits to the degree to which the network costs can be separately attributed to individual users.

Trans Power's transmission charges will be clearly separated from Electricorp's energy charges. The proposed pricing structure consists of three components: asset-related charges; demand-related charges; and energy-related charges.

Perhaps the most important asset-related charge is the transmission network charge, which is the major asset-related charge. It is calculated by determining the assets which have been provided to supply each user. Three factors contribute to this figure:

- *distance from load generation* - transmission costs increase with distance;
- *economies of scale* - large scale users realise scale economies per unit of electricity supplied; and
- *security of supply* - users provided with multiple lines to enhance security of supply should be charged for those assets.

The transmission network charge takes account of these factors through complex calculations that compute the contribution of different power flows through the grid to the power taken off at each point. Hence:

> Each user's transmission usage and consequently network charge will change as system operation changes. In particular, usage will vary throughout the year. The annual transmission network charge covers all the different usage patterns by calculating power flows over load/generation scenarios which are representative of actual use over a year. (Trans Power 1991)

The introduction of this charge departs from the practice, pursued in Australia and formerly pursued in New Zealand, of charging customers in different regions uniform tariffs. As detailed in Appendix 5, uniform tariffs result in a cross-subsidy in favor of higher cost regional customers.

It is envisaged that the second price component, the demand charge, will assist in providing price stability. It is set at a uniform rate, so as to provide some averaging of costs to all grid users. Trans Power (Trans Power 1991, p.6) have argued that the charge:

> ... represents the "common good" aspects of connection to the network, and provides Trans Power with a means of signaling transmission constraints (or lack of constraints) ... In the absence of demand charges, immediate recovery of all network revenue by transmission network charges alone could result in sudden large price increases to some users.

The bulk of the demand charge will be related to controllable loads, with a small amount of additional revenue being derived from actual demand - through pricing that reflects transmission constraints. This charge reduces the revenue that needs to be recovered by the transmission network charge, and reflects:

> ... the emphasis given to price stability during the transition from the present fully-averaged delivered energy prices to prices containing more user specific transmission charges. (Trans Power 1991, p.7)

Finally, energy-related charges cover costs associated with transmission losses, the maintenance of spinning reserve and other overheads.

Overall transmission prices are to be calculated for each connection point to the network. The connection point charges, network charges and most demand and energy charges will be calculated before each year, and will be charged on a fixed monthly basis.

A new grid-extension policy is to be introduced, which will require users to pay the full cost of any new investment they have requested Trans Power to make. As a result, Trans Power is currently only proceeding with new projects that users have agreed to fund. This policy is an extension of the user pays thrust of the transmission network charge to capital investment policy, and will result in a grid more in tune with user preferences.

Conclusions

As in the case of the UK ESI reforms, the most important element of the New Zealand scheme is the ownership and operation of the separated transmission grid. The similar direction of the two reform programs invites comparison. The planned ownership of Trans Power has avoided the bias towards the distribution companies that occurred with the NGC in the UK. However, while the NGC was conceived of as the centre of a spot market in electricity which would promote competition in the generation segment of the industry, at this stage the New Zealand reforms treat competition in generation more incidentally. Competition in this sector may change with the Trans Power Establishment Board's report on the creation of a wholesale market later this year. More attention is paid in the New Zealand system to the structure of charges attributable to transmission. Trans Power will oversee a regime of mainly fixed prices that apportion transmission costs in some detail. The emphasis of this structure is on user pays pricing, and the eventual elimination of cross-subsidies.

In the Draft Report hearings, CRA alluded to two problems associated with the New Zealand reforms:

> One has been, we think some fairly blatant movement in the asset valuations so that the disproportionate share of the total assets brought by Electricorp in generation and transmission ended up in the transmission basket such that the general level of transmission charges, or the percentage of revenue ... is about twice what you would expect in the Australian states. This of course has the effect of depressing the asset value on the generation side which is where you are encountering competitive pressure, of course.
>
> The other one is setting up a pricing regime that effectively averages the cost of transmission over the whole of New Zealand even though there are some very special, almost dedicated transmission links like a DC link right up the middle of the island.

The first criticism, if true, would result in a less competitive generation sector, because new entrants would have to compete with a large generator that faced less than full costs. They would also be burdened with transmission charges that exceeded true cost, which would reduce the size of the market they could reach.

Natural gas

Background

In New Zealand, most gas production, transmission and reticulation is carried out by private companies. The major production site is Maui, which supplies more than 90 per cent of New Zealand's natural gas. Production and transmission activities are dominated by Petrocorp, which was sold to the private sector in 1987. The Petrocorp subsidiary National Gas Corporation (NGC) is responsible for all of New Zealand's transmission pipelines. Reticulation is undertaken by several private gas companies, some of which are subsidiaries of Petrocorp, and five municipal gas utilities which operate in exclusive franchise areas. Petrocorp subsidiaries controls 40 per cent of the retail gas market.

Historical operation of the regulatory system

Regulation of the New Zealand gas industry began with the Petroleum Act 1937, which regulated the construction and operation of pipeline systems. It requires that all high pressure petroleum pipelines, including natural and manufactured gas, to be authorised by the Minister for Energy. The Act also contains common carrier provisions that allow access to pipelines by those who are not holders of authorisations. Such access can be achieved either by approaching the pipeline owner directly, or the Minister of Energy - who has an obligation to hear the arguments of both parties involved. These common carrier provisions do not apply to the distribution networks.

The 1982 *Gas Act* gave gas reticulation utilities an exclusive franchise over designated areas, with an obligation to supply all consumers. It also imposed rate-of-return regulation on gas distributors. Additionally, the Act contains an 'uneconomic supply' clause which provides an exemption for franchise holders faced with connecting consumers from whom the cost of supplying would not be fully recouped.

In October 1987, the Minister for Energy made a commitment to create a 'competitively neutral environment' for the gas industry and stated that 'changes [would] be designed to enhance competition at all levels of the industry' (New Zealand Ministry of Energy 1989, p.11).

Shortly after this commitment, the Government sold its 70 per cent interest in Petrocorp. With the vertically integrated Petrocorp now a private enterprise, the Government considered it necessary to review the *Commerce Act*.

Despite calls for industry-specific legislation, the Government decided to continue to rely on the *Commerce Act*, as well as information disclosure requirements, to restrain monopoly power. Both Petrocorp and local utilities were made subject to information disclosure requirements. These requirements are intended to serve two functions:

- to enable the Commerce Commission, consumers and potential competitors to detect abuses of a dominant position by industry players, and thence seek redress through the Commerce Act. However, there is no formal mechanism for assessing such claims; and

- to reduce monopoly power by providing potential competitors with information that enhances their bargaining position *vis-a-vis* incumbent operators.

The review of the *Commerce Act* also led to new legislation removing reticulation companies' exclusive franchises and the obligation to supply. The gas trading division of these authorities is to be restructured into companies operating on a commercial basis. The Government also indicated that price controls on retail supply would be removed once the other decisions had been implemented (New Zealand Ministry of Energy 1989).

The gas industry is now subject to the same broad competitive provisions of the Commerce Commission as the ESI. The *Commerce Act* currently provides the main regulatory control on the wholesale market, through rate-of-return regulation of gas wholesale prices.

Current conditions and future prospects

The Ministry of Energy (1987) noted that certain features of the industry need special consideration. Wholesale price controls as they are currently imposed may lead to problems with interfuel substitution decisions, because they encourage current consumption, while hampering long-term investment decisions in the industry. Because prices under Maui and Kapuni gas contracts are so low, there is a market drive towards overly rapid depletion of reserves.

Other problems within the industry include:

- the dominance of the Maui field, both in price and size, effectively transfers much of the risk of energy investment to any new would-be suppliers; and

- the Maui contract has take-or-pay provisions that have, like similar contracts in the US, 'a strong distortionary impact on commercial decisions', such as forced early use of gas.

> A better pricing arrangement would involve a fixed component as a capital contribution and a variable component equal to the producer's opportunity cost for the gas.

If wholesalers were allowed access to the pipeline transmission system on a neutral basis a more competitive outcome might be achieved. For this to occur, reform proposals need to consider the potential conflict of interests evident in Petrocorp's ownership of both pipeline transmission and wholesaling functions. If these functions are to remain under Petrocorp's control, the transmission function would need to be regulated closely. In the event of wholesale price deregulation, arrangements would need to be in place to ensure that optimal access to transmission facilities are maintained.

The Ministry of Energy has suggested that a separate pipeline organisation could be established on commercial lines. This option would require less regulation, particularly if the organisation's ownership was adequately distributed amongst wholesale operators. Under such a scheme, the incentive to minimise transmission costs would lie with those who had most to gain. Non-discriminatory behavior towards the various participants requiring access would also be encouraged.

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APPENDIX 10: ELECTRICITY POOLING AND COORDINATION ARRANGEMENTS

Electricity pooling and coordination arrangements range from limited informal transactions to complex highly coordinated pooling agreements. Power pooling has been employed extensively in the United States and Europe. Tight power pools allow the achievement of most available system economies. Such pools approach unitary systems in their level of coordination. However, segmented and more competitive ESIs such as those operating in or proposed for the Netherlands, New Zealand, Sweden and the United Kingdom seem more likely to capture the benefits of both competition and coordination.

10.1 Introduction

A variety of pooling and coordination arrangements are used by utilities to organise the production and marketing of electricity. The challenge for such systems is to achieve the benefits of integration and coordination while, at the same time, maintaining competitive pressure on suppliers.

In this appendix, the implications of different pooling and coordination arrangements for the performance of the ESI are examined. The nature of pooling and coordination tasks is described in Section 10.2. Following this, the range of organisational arrangements employed to perform these tasks is considered (Section 10.3). Selected overseas power pools are discussed in more detail in an attachment to this appendix.

10.2 Pooling and coordination transactions

Pooling and coordination arrangements can lead to the realisation of greater efficiencies and increased reliability in a range of areas. The most easily achieved, and significant, economies from pooling operations arise from exchanges of 'opportunity' or 'economy' energy between utilities. Such exchanges occur when the marginal production cost difference between utilities exceeds the cost of transmission losses in transferring power from one system to the other. Further economies can be realised by sharing operating reserves, because total reserve requirements can be reduced by setting them for an entire pool instead of for individual systems. Other gains can accrue from the coordination of:

- grid and capacity extension programs;
- maintenance schedules; and

- emergency outage procedures.

These measures are discussed in more detail in Appendix 6.

10.3 Alternative pooling and coordination arrangements

Electric utilities have developed a diversity of institutional arrangements to perform the pooling functions outlined above. These arrangements link operational and planning aspects of member utilities activities to provide efficient outcomes. They are primarily concerned with generation and transmission activities. Distribution has only minor functional importance in the performance of pooling and coordination operations (with the possible exception of the segmented market model, considered in Section 10.3.4)

Pooling and coordination arrangements can be classified by the extent to which they rely on internal or externally based mechanisms to undertake transactions. At one extreme, most pooling transactions can be internalised within a single vertically integrated organisation. Within such organisations, internal 'command and control' structures determine outcomes. At the other extreme, all such transactions occur between separate organisations. These transactions may take the form of voluntary contract, or non-contract, agreements. Alternatively they may be undertaken within the formal framework of an established market. Between these two extremes fall coordination arrangements that combine elements of internal and externally based transactions. The following list illustrates this continuum:

- single utility systems;
- bilateral interchanges;
- power pools - both loose and tight; and
- segmented market systems.

Examples of each of these are outlined in Table 10.1.

10.3.1 Single utility systems

The single utility system is characterised by complete or near complete vertical and horizontal integration, and is responsible for the supply of electricity in a given area. Such arrangements are usually the result of formal legislative provisions, and may involve either private or public enterprises. Activities such as system planning, merit order despatch and maintenance scheduling are undertaken internally by single utility systems. There is minimal dependence on market transactions. Typically, such transactions are limited to the purchase of raw materials, fuel and other inputs and the retail sale of electricity. Generation, transmission and sometimes distribution are fully integrated.

Table 10.1: Examples of alternative pooling models

System	Unitary system	Bilateral interchange	Loose Pool		Tight Pool	Market system
Example	*SECWA*	*ECNSW-SECV*	*Florida Coordination Group*	*Nordel*	*NEPOOL*	*UK Model*
Operating framework						
Membership	SECWA	ECNSW and SECV	4 large utilities, 33 smaller	Utilities in Finland, Sweden, Norway and Denmark	45 utilities, with varied ownership	All UK ESI
Agreements	State enabling legislation	Bilateral	System coordination agreement	System coordination agreement	Formal binding NEPOOL agreement	Binding legislation
Entry barriers	Legislated monopoly	Presumably open to other state generators	Open to all Florida utilities	None	Open to all New England utilities	Open
Ownership controls (generation, trans, dist)	Strict public ownership	Strict public ownership	None	None	None	None
Regulation	High degree of intervention	No specific regulation	FERC & State Commission	No cross border regulation	FERC and State Commissions	Transmission and cross-ownership regulation
Horizontal integration	Full integration	Full integration	Low	Varied	Low	Low
Vertical integration	Full integration	Generation, transmission and some distribution	Varied, several integrated utilities	Varied	Complete	Very low
Decision mechanisms						
SR power interchange	None	Informal bilateral	If capacity is available	Informal bilateral	Automatic	Spot market
LR power interchange	None	Bilateral contract (generator to generator)	Bilateral contract (mixture of participants)	Bilateral contract (generator to generator)	Guaranteed	Bilateral contract (mainly generator to dist)
Intra-pool grid access	N/A	None	Open access	Partially open	Open access	Common carriage
Maintenance scheduling	Centralised	Consultation	Informal, no central control	Non-sanctioned guidelines	Sanctioned directives	Non-binding NGC recommendation
Spinning reserve	Centralised	Shared	Based on system requirements with proportional contributions	Based on system requirements with proportional contributions	Based on system requirements with proportional contributions	Market based through a pricing component
Unit commitment	Centralised	Partial coordination	Decentralised, with computer brokerage system	Decentralised - no brokerage system in place	Centralised	Price quote based merit order
Capacity increment	Centralised	Independent	Non-sanctioned guidelines	Non-sanctioned guidelines	Sanctioned directives	Fully decentralised market based
Grid extension	Centralised	Independent	Non-sanctioned guidelines	Non-sanctioned guidelines	Sanctioned directives	In response to capacity expansion

Some Australian utilities, such as ETSA and SECV (and formerly ECNSW), have extended vertical integration to the control of mining operations, so that electricity production from coal face to final delivery occurs within a single organisation. Overseas examples of highly integrated utilities are to be found in Italy, France and the English ESI prior to its reform (see Appendix 9).

On the other hand, ECNSW and QEC do not incorporate distribution. However, their ownership of both the generation and transmission industry segments allows them to undertake most of the system coordination functions that are the subject of this appendix.

10.3.2 Bilateral interchanges

Bilateral interchanges of energy, either on a short term basis or over longer periods of time are the simplest form of power pool. They illustrate fundamental transactions that occur in more complex multilateral pools.

Bilateral interchanges can be categorised as either opportunity transactions or contract transactions.[1] These transactions are undertaken on a voluntary basis between utilities, without regulatory compulsion. However, in some examples, such as within the United States, regulatory provisions require that such transactions adhere to cost-of-service or other guidelines.

Opportunity transactions

Opportunity transactions encompass the exchange of power between utilities on an economy basis. Each utility has sufficient capacity to supply its customer base independently, with one or both utilities having surplus capacity. Differences in generation plant size, mix and load characteristics provide opportunities for gains from trade. For instance, one system may wish to reduce load on an expensive peaking unit while another may have surplus base load electricity available that it wishes to sell. The tradable position of each system will change over time depending on demand and supply conditions, hence the 'opportunity' nature of these exchanges.

The conditions for these exchanges are established by formal or informal bilateral agreements. For example, such an agreement may allow the utilities to schedule their units in advance to take advantage of such exchanges. Alternatively, they may simply agree to trade energy to cover unexpected outages, or increases in demand, on an informal basis.

1 These are analogous to the coordination and requirement transactions described in Appendix 9.

Contract transactions

Contract transactions govern exchanges of electricity in cases where one utility lacks sufficient capacity to supply its customer base, or where medium or long term opportunities exist for accessing lower cost energy from another system. This can be negotiated as a specified volume of energy, or as contracts that require a utility to provide a specified proportion of another utility's load requirements over a given period of time. In addition to sales between integrated utilities, these may entail sales between generators and independent distribution companies.

Within the United States, long term contracts for transmission between utilities have existed for several decades. Such contracts typically remain in force for many years. A contract of this type has recently been agreed between ECNSW and SECV. It specifies the conditions for a long term exchange of 300 MW of power between the two utilities. This is additional to the opportunity exchanges that have occurred between the two utilities since the 1960s.

10.3.3 Power pools

A power pool is a collection of utilities that coordinates planning and/or operations so as to achieve greater overall system reliability and economy. More complex pools embrace a much wider selection of activities than just opportunity or contract interchanges. Joskow and Schmalenesee (1983) used the following definition of a power pool:

> *The term power pool generally refers to formal and informal agreements among independent utilities to coordinate some or all of their investment and operating activities.*

Informal pool agreements cover a variety of non-contractual undertakings by participants to facilitate system coordination activities, such as maintenance scheduling and emergency procedures. Essential features of these agreements are that they have no legal force and are voluntary and cooperative in nature. In contrast, formal pooling agreements are legally binding, and usually specify member responsibilities over a wider range of variables.

Power pools fall into two categories - loose pools and tight pools. Tight power pools coordinate the activities of member systems to a high degree, leaving little autonomy to utility management's. Loose power pools allow members larger degrees of freedom. Consequently, member utilities maintain autonomy in a range of areas. The 'looser' a pool is, the more likely it is that activities will be undertaken on an informal basis.

In both loose and tight pools, there are typically at least some vertically integrated utilities, but there may also be independent distributors and generators. Ownership arrangements can be similarly diverse. Participants in United States and European power pools are owned by municipal, cooperative, state, national and private authorities. At the beginning of the 1980s, formal power pools accounted for some 60 per cent of electricity generated in the United States. The Nordel and UCPTE power pools incorporate most countries in Western Europe.[2]

An important issue concerning the realisation of gains from pooling is transmission access rights and obligations. It is axiomatic that any utility seeking to exchange power with another utility must access the transmission grid to do this. In cases where all or part of that grid is owned by a third party, an agreement must be reached with that party on access rights. In tighter pools, universal transmission access rights and obligations are specified. These agreements detail payment schedules for the use of facilities. In looser pools, access rights are often negotiated bilaterally.

Loose power pools

Loose power pools attempt to promote opportunity interchanges between members by opening access to transmission facilities. They also provide a framework for the coordination of technical aspects of system operation, such as frequency control and operating reserves, to enhance operational reliability. Well known loose pools include Nordel, UCPTE and the Florida Coordination Group (FCG). Nordel and UCPTE each straddle a number of countries, while the FCG (and some similar American pools) operates within a single state of the United States.

Different power pools mix the degree to which alternative pool functions are pursued. However, the following distinguishing characteristics of loose pools can be identified:

- unit dispatch is undertaken on a decentralised basis, with individual utilities committing units according to their own requirements;
- there is usually no formal pool-wide agreement governing short or long term energy exchanges. Instead, agreements are made between utilities on a bilateral basis; and
- while the pool organisation often makes recommendations in relation to operating and planning activities (such as grid and capacity extension), it cannot penalise members for failing to conform to its guidelines.

Coordination of operations involving trade in electricity, sharing of operating reserves, emergency procedures and maintenance scheduling is undertaken on an informal basis in loose pools, if at all. The loose pooling approach is flexible enough to allow members to tailor participation to meet their needs. However, it may not allow full coordination of all aspects of pooling operations, and, therefore, the realisation of associated economies.

2 The Union for the Co-ordination of the Production and Transmission of Electric Power (UCPTE) covers Austria, Belgium, France, Germany, Greece, Italy, Luxembourg, the Netherlands, Portugal, Spain, Switzerland and Yugoslavia. The five members of Nordel are Denmark, Finland, Iceland, Norway and Sweden. Although a member of Nordel, Iceland is not connected to the grid.

While the pool itself does not become involved in short or long term energy exchanges, it may establish mechanisms that facilitate efficient bilateral exchanges between members. Several examples of such frameworks exist:

- the FCG employs a computer operated energy brokerage system that issues hourly buy and sell quotes from interested member utilities, so as to encourage efficient exchanges of energy;
- Nordel requires that information about forecast marginal production values should be exchanged openly between all participating operational management's on a weekly basis. Transactions are undertaken so as to minimise marginal costs in view of this information; and
- UCPTE's Laufenburg centre monitors interchanges between pool members, acting as a clearing house for energy-hour 'credits' and 'debts'.

Transmission access arrangements are similarly varied. A recent ruling of the European Commission is intended to make third party access to transmission mandatory within the EC. If successful, this ruling will open up UCPTE's electricity grid by allowing any supplier to provide energy to any user, regardless of location or nationality.

Within the FCG, member utilities have assured access to the grid for short term exchanges of power. However, they must negotiate with the various grid owners for access to transmission facilities for longer term power exchanges. Further, as described in Attachment 10.1, transmission charging methods differ between the pool's grid owners.

Tight power pools

Arrangements governing the operation of tight power pools are more encompassing than those for loose pools. Tight pools attempt to maximise the gains from coordination. Examples are found mainly in the United States, where they account for about 25 per cent of the nation's generating capacity. The Pennsylvania-New Jersey-Maryland Interconnection (PJM), the New York Power Pool (NYPP) and the New England Power Pool (NEPOOL) are frequently quoted examples of this type of organisation. In Europe, the ESI of the Netherlands effectively operates as a tight pool, centred on the transmission coordination body N.V. SEP. The tightest of these pools is NEPOOL. It is discussed in more detail in Attachment 10.1.

As with loose pools, tight pools are organised on a voluntary basis and membership is generally open to any utility within a given state or region. Member utilities may be fully integrated or operate only in the generation or distribution sectors. Typically, tight pools contain a reasonable proportion of vertically integrated utilities.

The breadth of coordination and control activities undertaken by a tight pool is such that it mimics the operational integration of a single utility organisation. This coordination is facilitated by multiple transmission linkages between member utilities that enable easy exchange of power.

Participants are required to surrender a significant amount of operating and financial autonomy to the pool in order to capture wider system economies. Formal requirements can extend to all major pool operations and penalties may be imposed for failing to meet these requirements.

Perhaps the most striking indication of the cohesion of tight pools is the nature of their unit dispatch procedures. Typically, all generating units are dispatched by a central control centre to meet the pool's load and spinning reserve requirements at minimum cost. Both PJM and NEPOOL operate as single control areas, with ex-post accounting of energy exchanges. These arrangements closely mirror the internal merit order dispatch of independent utilities. NYPP, however, operates more loosely as a collective of seven distinct control areas. The dispatch order for units is issued in advance. Individual member utilities have the discretion to transfer dispatch control to their own operations centre. Implementation of the pool's dispatch schedule is optional, allowing for reliability constraints, and is not monitored by the pool.

PJM and NEPOOL differ in their approaches to grid planning and extension.

Within PJM, the need for new grid and transmission facilities is identified by individual utilities, independent of the pool. Such facilities are then constructed by these utilities, or consortiums of utilities. PJM requires each member to pay an equitable proportion of costs, subject to negotiations between relevant utilities.

NEPOOL has developed a more sophisticated grid and capacity expansion process. All transmission assets exceeding 69 kV and owned by NEPOOL members are classified as pool transmission facilities (PTF). NEPOOL's planning committee conducts studies to determine the optimal PTF structure. Although member utilities have ultimate authority over the extent and nature of additions to their respective networks, their decisions are influenced by the pool. This influence is exercised by the pool in the following ways:

- the Planning Committee reviews the transmission plans of all members to determine their consistency with the pool's needs and requirements. Those considered acceptable are granted 'pool-planned' status. This allows individual pool members to receive revenue from the pool according to other members' use of the facilities;

- the pool can recommend that individual members build transmission facilities regarded as necessary to the pool for reliability or economy. All members must contribute to such assets in accordance with the benefits they receive from the facilities, as specified by the Planning Committee.[3] The concerned utility is reimbursed beyond its proportional share; and

[3] Because of the difficulty in determining the proportional contribution of members to pool approved PTF, NEPOOL in 1980 was moving towards designating all PTF as pool approved.

- the pool reviews individual members' plans to determine their effect on pool-wide reliability and operation. If a utility's plan is considered detrimental in these respects, it may not proceed with their implementation until those plans have been modified to meet the pool's criteria.

Similar arrangements exist for new generating capacity. Pool approved generation units are guaranteed access to PTF for such purposes as transferring opportunity exchange energy, emergency replacement energy and long term contract fulfillment. Non-pool approved energy receives less generous terms of access to PTF.

These arrangements provide strong incentives for utilities to cooperate with the planning committee's expansion program. However, they differ from the internal command and control directives of independent utilities by allowing utilities the discretion to refuse to comply, albeit as some cost. Hence, these arrangements balance the desires of the individual utility with those of the pool as a whole. Presumably, non-compliance charges would be set at levels that reflected the difference between the net value of the relevant facility to the pool and utility respectively.

10.3.4 Segmented market systems

The pooling and coordination models considered in Sections 10.3.2 and 10.3.3 are voluntary associations of utilities that aim to capture the economic and reliability benefits of coordination. In contrast, segmented market systems are the result of formal legislative provision, and hence are non-voluntary. In this respect they resemble legislated public monopoly systems.

A further difference between the segmented market model and voluntary pooling approaches relates to industry structure. As discussed above, members of voluntary pools may have a variety of structures, and may be vertically integrated. In contrast, segmented market systems are premised on an industry structure of vertical segmentation. There is also horizontal segmentation in generation and distribution. This segmentation is necessary to enable market interactions to be the dominant form of transaction between industry players. By requiring generation and distribution companies to contract on the market for the full set of pooling transactions, an incentive structure is established that is intended to promote cost reduction and service quality in the long term.

Within the segmented market model, the most frequently undertaken transactions are market based exchanges between participants in different industry segments. These exchanges occur on highly organised markets. They have functions that reflect the coordination activities undertaken by power pool authorities, or the internal command and control transactions within single utility systems. The competitive engine room of this model is the generating sector, in which companies compete to supply users through the open grid at lowest cost. The reformed United Kingdom and New Zealand ESIs are examples of segmented market systems.

Operational details of these two industries are described in Appendix 9, and bear some similarity to the Commission's recommendations in Chapter 7.

The various ownership proposals for the transmission grid in segmented market models have compositions which obviate the need for significant regulatory supervision. For example, the New Zealand transmitter, Trans Power, is to be owned by a 'club' of generators and distributors. Similarly, the UK transmitter, NGC, is owned by the distributors, which are separated at arms length from decision making. These alternatives, particularly that of New Zealand, create strong incentives for transmission owners to minimise costs, provide high quality service and make appropriate investment decisions. In short, the conflict between the interests of the transmission ownership and that of the pool as a whole is minimised.

The transmission grid operator is responsible for most pooling and coordination activities. For example, the UK's NGC is required to undertake planning for, and coordination of:

- the release of sections of the grid for maintenance and repair; and
- the release of generating units for maintenance on the basis of data provided by the generators.

These activities are undertaken as part of the NGC's forward plan, in line with prescribed security standards. The NGC's recommendations in this second area are not binding on generators, who have the choice of undertaking maintenance outside pool guidelines. In formulating the forward plan, the NGC considers the impact of actual and potential generation and transmission projects on the grid's operation.

So as to promote appropriate investment decisions, the NGC's pool input price, which is received by generators selling to the grid, has two components. The first is the system marginal price, which reflects the marginal cost of the most expensive generator currently selling energy to the grid. As such, it is a measure of variable costs. Second, the capacity credit is a measure of the probability of the system failing due to inadequate capacity as well as the value that users place on system reliability. This second component is intended to cover the generators' long run fixed costs. It increases in times of capacity shortfall, and thus attracts more capital into the generating sector. Further, by incorporating a component that reflects pool customers' willingness to pay to avoid supply shortfalls, it promotes a level of system reliability that is a function of market signals.

Decisions to install new generating capacity are made by private investors independent of the NGC. Industry players install generating units that they consider will generate a return in view of market conditions. Their decisions are influenced by the size of the capacity credit, which acts as an index of the balance of demand and available generating capacity.

The NGC is required by its licence to offer terms to relevant applicants for the use of, and connection to, the transmission grid. Upon acceptance of these terms, connection to the NGC grid takes place. Hence, grid extension occurs automatically as new generation projects are completed. As such, the NGC cannot directly determine the pattern of grid extension. In this respect, it exercises less power over grid extension than the NEPOOL planning committee. That body, similarly to management in single utility systems, is able to specify the precise location and size of new grid and capacity projects.

Attachment 10.1: Selected power pooling models and proposals

In this Attachment, more detail is provided about examples of typical utility systems. Particular attention is given to the access rights and obligations of member utilities, as well as grid and capacity planning mechanisms.

Several pooling and coordination proposals for south-eastern Australia were received from participants. Several of these referred to the Nordel example as a potential model for a future Australian Pool. CRA proposed a modified version of this model. This is also described.

The following four examples are considered:

- UCPTE;
- FCG;
- Nordel; and
- CRA's proposal.

UCPTE

In 1989 the twelve member countries of UCPTE had a combined electricity capacity of 381 000 MW, making it the largest power pool in the western world. UCPTE is an extremely loose pool with the primary objective of facilitating opportunity energy exchanges. The pool ensures that separate networks are operated in harmony, and specifies reserve capacity and other safety guidelines. Each participating utility is responsible for meeting its own demand commitments, whether by its own capacity or through contracted power. UCPTE is not allowed to enter into electricity supply or demand contracts on its own behalf, and has no permanent staff or secretariat.

There is no centralised despatch of generating units. Rather, utilities trade between themselves and exchange energy on an informal basis. According to UCPTE, this interchange is facilitated by 'an efficient telecommunications network' and the friendly relations between despatchers in the different control centres (UCPTE 1989). An essential element of this network is the Laufenburg metering centre in Switzerland which monitors energy exchanges between UCPTE members and acts as a clearing house for outstanding balances.

The European Commission has recently moved to establish open access to the UCPTE transmission grid. This will enable co-generators and end users to contract with each other for electricity supply, regardless of their location within the grid (see Appendix 9). This move makes UCPTE a tighter power pool because it allows generation assets equal access to transmission, regardless of national boundaries or ownership.

Florida Coordination Group

The Florida Coordination Group (FCG) is an example of an extremely loose and informal power pooling arrangement. The FCG, a pool with 12 member utilities, accounts for 98 per cent of electricity supplied in Florida. It operates without any formal agreements. Instead, the operational framework of the group consists of:

- bilateral transmission agreements between owners of transmission facilities and other systems requiring use of these facilities in pool operations;
- bilateral interconnection agreements that delineate the conditions, types and payment provisions for power interchange amongst members;
- informal agreements that govern access to capacity, installed capacity obligations, operating reserves, emergency procedures and maintenance scheduling; and
- a computer based energy brokerage system to assist in the efficient interchange of energy between systems on a short term basis (via hourly buy and sell quotes from interested utilities).

Two utilities, Florida Power Corporation (FPC) and Florida Power and Light (FPL), own almost all of Florida's transmission assets. Hence, access to the grid is determined by their respective policies. FPC grants pool members access to its grid for all short term opportunity and contract energy exchanges at a flat rate, regardless of distance. FPL allows similar rights, but only after the negotiation of bilateral or multilateral transmission service agreements. Charges vary according to distance.

As a result of the disparity between these two company's practices, there is no uniform transmission tariff or practice over the FCG grid.

Grid extension decisions are made by individual utilities, subject to non-binding recommendations by the Planning Committee. Additionally, each utility has an informal commitment to meet its own generating requirements and its share of operating reserves. Utilities have informal access to this capacity when unexpected outages occur.

Nordel

The ESIs of Denmark, Finland, Norway and Sweden coordinate their operations through Nordel. The stated aim of this coordination is to:

> ... minimise the total production costs in the Nordel system. This is achieved by constantly trying to ensure that the production units are used in order of increasing cost, irrespective of which country they are located in ... [so that] production in any one country will then probably not correspond to the consumption in that country. (Nordel 1980, p.20)

Similarly to the FCG, Nordel does not have authority to issue directives to pool member regarding grid or capacity extension.

Instead it issues recommendations through a planning committee which constitute guidelines for cooperation. Other important rules governing Nordel's operations are that:

- power exchanges are agreed upon bilaterally, and independent of Nordel;
- sales contracts are based on the 'marginal cost principle', calculated according to guidelines specified by Nordel;
- participation in power exchanges is voluntary;
- information about forecast marginal production values, planned line outages, spinning reserve and transmission limitations are exchanged openly between all the participating operational management's on a weekly basis; and
- there is a specified cost plus profit limit for energy exchanges where buyers have no alternative supply.

Each nation has its own coordination centre and programs unit commitment independently. There is no overall Nordel operations management. However, the Nordel control centre at Vattenfall (the Swedish control centre) has coordinating responsibility for frequency control and demands on operating reserves. Individual national operation management's are otherwise responsible for management of the interconnected Nordel system. Hence, they are responsible for the operation of their own systems and for power exchanges with neighboring systems. The considerable differences between the resource endowment and system dimensioning of Nordel participants provide a significant incentive for cooperation and trade.

CRA model

In its response to the draft report, CRA proposed the creation of an Eastern Australian Power Pool (EAPP), along broadly similar lines to the Nordel model. In support of this proposal CRA argued that:

> ... an extension of the existing Three-State arrangements, to form a more extensive loosely coupled Eastern Australian Power Pool with its rules for operation, and the rules for interconnection made public and extended, with a proper involvement by private sector players in the Industry, offers the most efficient system for Australia.

CRA argued that such a pooling arrangement was superior to the United Kingdom's segmented market based system because it would not require the creation of a single, autonomous, transmission authority. Rather, a pooling authority could undertake system coordination functions, while grid assets would remain in the hands of separate utilities.

Within these utilities, the operation of such assets would be separated (or ring fenced) from other activities:

> Providing that the owning organisations of the physical transmission assets agree to comply with certain rules ... ownership can, and desirably should, remain with separate Authorities, and/or private Companies.

Hence, transmission assets remain in public or private utility hands. Respective transmitters would then be subject to yardstick competition. Thus, organisations could extend their transmission links themselves, within the sanction of the pool.

The pooling authority would:

- set technical standards for such areas as RPM and spinning reserve;
- allow generator-distributor links sanctioned only within EAPP;
- estimate future generation or transmission capacity;
- publish information in support of yardstick competition; and
- operate under a board of directors selected on business criteria.

CRA envisages that when the need for additional transmission or generation capacity was identified, a tendering process could be implemented by the pooling authority to attain the most economic extension possible.

Participants in the pool could be vertically or horizontally integrated. Some transactions within the EAPP would be via contract, and others through internal organisation. For example, an organisation holding a distribution licence could secure generation capacity to meet its means by:

- securing an ownership share in generation plant owned by licensed generators;
- entering into long or short term contracts for capacity from a licensed generator; or
- arranging with customers for interruptibility of supply.

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APPENDIX 11: PROFILE OF CURRENT ENVIRONMENTAL POLICIES AND PROGRAMS

A range of Commonwealth, State and Territory Government regulatory controls are employed to minimise the environmental impact of the electricity and gas supply industries. In some areas, governments and utilities sponsor research programs to help identify the environmental consequences of the industries' operations and to develop technologies to limit harmful emissions. In all states and territories, energy conservation programs are being developed.

11.1 Introduction

The generation of electricity and the transmission and distribution of gas and electricity pose environmental problems. This appendix provides an overview of the policy framework and programs within which Commonwealth, State and Territory Governments address these environmental problems. It is also relevant to the requirement in the terms of reference that the Commission report on initiatives involving load management and energy conservation. Policies relating to load management and energy conservation are addressed in more depth in Chapter 10 and Appendix 12.

Initiatives which address the environmental problems can be classified as: infrastructure planning requirements; rehabilitation requirements; emission and discharge controls; energy conservation initiatives; and renewable energy projects. The regulatory requirements are predominantly imposed by the state and territory governments and operate either through the general state environment protection legislation or the environment provisions of specific gas or electricity Acts.

The Commonwealth's ability to impose environmental controls is limited by its constitutional powers. These powers may currently be exercised if: a corporation or a Commonwealth authority is involved; export licences are required; foreign investment approval is sought; or Australian commitments to international treaties, such as world heritage, need to be supported.

The Commonwealth is also involved in the development of international initiatives (eg support of work by the Intergovernment Panel on Climate Change); coordination with the states of a national approach through bodies such as the Australian Minerals and Energy Council (AMEC) and Australian and New Zealand Environment Council (ANZEC); and assistance for the development of new technology through the National Energy Research, Development and Demonstration (NERD&D) Program.

11.2 Infrastructure planning requirements

In common with most other industries, projects proposed by the electricity and gas industries have been required to conform to environment guidelines. These requirements may derive from Commonwealth legislation, general state environmental legislation, and/or the specific clauses within the Acts which govern the operation of the electricity authorities and the construction of gas pipelines.

Commonwealth powers derive from the *World Heritage Properties Conservation Act 1983* and the *Environment Protection (Impact of Proposals) Act 1974 (EP(IP)A).* Under these Acts, the Commonwealth can restrict development in world heritage areas and can require that an environmental impact statement (EIS) be prepared during the formulation of certain development proposals. DASETT stated that 'most major electricity and gas supply projects are subject to some Commonwealth control in relation to their environmental impact'. For instance, in apparent accordance with the requirements and procedures of the *EP(IP)A,* PAWA prepared an EIS for the Marrakai-Jabiru 132 kV transmission line which required easement through Kakadu National Park.

Electricity and gas developments are primarily subject to the environmental planning requirements of the state governments. For example, the SECV is required to comply with:

> State Environmental Protection Policies other State government environmental policies and the giving of due consideration to environmental factors in the planning, design, construction and operational phases of every project.

Similarly, the ECNSW is required to prepare an EIS for most of its proposed developments. It must also comply with the State's general pollution control guidelines and seek approval from the State Pollution Control Commission (SPCC) prior to the installation or modification of any plant likely to cause or increase pollution.

Where an environmental impact statement is required to be prepared according to both Commonwealth and state guidelines, procedures exist which provide for the preparation of a single document to meet both sets of requirements. For instance, the proponents of the Hill River development in Western Australia prepared a single environment assessment report which met the Commonwealth requirements for a draft environmental impact statement for the power station and the Western Australian Environmental Protection Authority's requirements for an Environmental Review and Management Program for the power station and an associated coal mine.

In Western Australia and the Northern Territory, pipeline legislation specifies that the granting of a licence for the construction of a gas pipeline is contingent upon whether flora, fauna or scenic attractions will be unnecessarily interfered with. The Australian Pipeline Industry Association

(APIA) stated that pipeline corridors are chosen to avoid environmentally sensitive areas and aboriginal sacred sites.

In Tasmania, the Environment Protection Act (1973) requires the HECT to consult with the Director of Environmental Control on how to avoid or reduce any pollution or unsightliness that might result from its work. Wherever possible, work that scars the landscape is done under the water line created by the new lakes (HECT 1990).

11.3 Rehabilitation requirements

Despite the statutory planning requirements, the construction and operation of gas and electricity facilities often results in the disturbance of adjacent land. Rehabilitation programs can limit any long term effects. In some circumstances, rehabilitation is required by statutory provisions. For instance, the licence conditions for the construction of gas pipelines in the Northern Territory and Western Australia require the immediate rehabilitation of any agricultural land. The APIA stated that modern regeneration techniques ensure that pipeline routes become almost invisible following construction. The efforts to prevent the spread of noxious weeds during the construction of the Wallumbilla to Gladstone pipeline was cited as an example of the industry's environmental awareness. The HECT (1988) stated that it has an on-going commitment to the rehabilitation of areas disturbed during its construction activities, and that the costs of rehabilitation represent 1.5 per cent of the capital cost of a scheme.

In New South Wales, the SPCC has undertaken investigations into the rehabilitation of a number of former gasworks and power station sites. These investigations have centred on the development of strategies for the removal and/or containment of a range of hazardous wastes such as organic contaminants, asbestos, lead and cyanides (SPCC 1989). In Victoria, the SECV is outlaying $2.5 million to redevelop the former site of the Newport Power Station into a recreation area (SECV 1989) and is continuing to develop techniques to rehabilitate overburden dumps (SECV 1990).

11.4 Emission and discharge controls

The generation and distribution of electricity and gas has the potential to emit pollutants which degrade the environment and impose health hazards. The extent of the potential problems created by these emissions is sometimes unknown. The most controversial and potentially most significant environmental issue pertaining to emissions is the increase in greenhouse gases and the potential for climatic change. This issue is the subject of considerable research. The possible cost and benefits to Australian industry of reducing emissions of greenhouse gases is the subject of a separate Industry Commission inquiry.

A number of different programs seek to limit the environmental problems associated with the utilisation of energy resources. The Commonwealth Government's approach involves a commitment to the development of energy conserving technologies and research into new and renewable forms of energy (see Prime Minister of Australia 1989).

Also, the Commonwealth has decided that, to the extent the matter is within its powers, nuclear energy will not be further developed as part of Australia's energy mix (DPIE 1988). The construction of nuclear power stations is also expressly forbidden by some state legislation. It is not clear whether these policies are to be reviewed in light of concerns over greenhouse gas emissions.

The approach adopted by state and territory governments to power station and gas pipeline emissions is based upon the imposition of emission controls developed after problems have been identified and researched. The New South Wales Government stated that the basis for the imposition of emission controls is related to technological considerations (what is achievable), community expectations, international standards and the capacity of the environment to absorb discharges. The Queensland Government stated that waste disposal and particulate emissions from energy supply facilities in that State are treated in the same way as for any large project.

The administrative mechanisms employed vary between states. For example, in New South Wales, power station emissions are constrained by the provisions of the licences issued by the SPCC and, in some circumstances, by the ECNSW's own environmental goals. The SPCC requires self-monitoring of source emissions, measurement of ambient air quality and verification that pollution control equipment functions correctly. An Environmental Audit Committee has been established within the ECNSW to ensure compliance with these requirements. This Committee has completed a number of audits of the power generation operations of the ECNSW. It intends to extend these studies to other areas of the ECNSW's operations.

Concerns have also been expressed about the possibility that electromagnetic fields, created by high voltage transmission lines, may pose health problems; in particular, increase the risk of cancer. After assessing a number of international studies, a CIGRE (1990) group of medical experts stated:

> ... the evidence for exposure to power -frequency electric and magnetic fields as a cause of cancer is not persuasive, and that any such relationship remains questionable.
>
> The matter is of sufficient importance, however, to deserve continued research.

The recent New South Wales Government (1991) inquiry into this matter concluded:

> It has not been established that electric fields or magnetic fields of power frequency are harmful to human health, but since there is some evidence that they may do harm, a policy of prudent avoidance is recommended. No reason exists for concern as to the effect of the fields on animals or plants.

The electricity authorities in the states have also undertaken studies to determine the environmental effect of their activities and have implemented programs to limit potentially serious impacts.

- A study undertaken by the ECNSW (1987) indicated that acid rain is not a problem in the Hunter Valley. A similar study by the SECV (1989) indicated that acceptable levels in the Latrobe Valley were not exceeded. However, the expected growth in emissions of acidic pollutants led to the Australian Environment Council (1989) recommending continued monitoring in selected regions, including the Latrobe Valley.

- More general investigations into air quality have indicated that: power stations are not a significant contributor to haze on days of poor visibility in the Latrobe Valley (EPA 1988); power stations are a significant, though not major, contributor to haze in the Hunter Valley (SPCC 1988); and ground level concentrations of emitted gases and particulates are low in the area surrounding Callide B Power Station in Queensland (QEC 1989).

- ECNSW has conducted investigations into the effect on the aquatic environment of releases of cooling water from the Central Coast power stations. The SECV (1990) reported that the quality of waste water discharged was generally within EPA licence requirements (breaches were attributed to operational difficulties) and that the adoption of improved water and waste water practices will result in reduced water intake, less contamination of wastewater and smaller discharge volumes.

- To assist the EPA in formulating a future noise policy, the SECV conducted the Latrobe Valley Noise study at a cost of $3.5 million. The SECV has also installed induced draft fan silencers at its Loy Yang A Power Station.

The electricity industry has been the user of a number of hazardous substances, for instance some older transformers use polychlorinated biphenyls (PCBs) as an insulating and cooling medium. The ESAA (1990) stated that the industry has undertaken a number of environmental audits to improve waste management and to ensure the early identification of any problems associated with the use and disposal of hazardous wastes such as PCBs, asbestos and chlorofluoro-carbons. The Snowy Mountains Hydro-Electric Authority has undertaken to replace PCB filled transformers with 'dry-type' transformers (SMHEA 1987).

Australian coals contain, in trace amounts, a number of hazardous elements, such as arsenic, fluorine, cadmium and various radioactive nuclides. DASETT stated that there is no evidence of environmental effects of emissions of these elements due to the burning of coal for electricity.

11.4.1 Greenhouse gases

An environment issue of increasing relevance to the electricity and gas industry is the potential for global climate warming from increased levels of greenhouse gases.

The response to this problem in Australia has involved the adoption of planning targets for greenhouse gas emissions and the development of response strategies. This approach is closely tied to the international response.

Internationally, the Intergovernment Panel on Climate Change (IPCC) has been involved in assessing scientific information on climate change, determining its impact and in formulating response strategies. The IPCC's First Assessment Report was presented to the Second World Climate Conference held in November 1990. The Conference urged that negotiations commence for an international convention on climate change.

The IPCC's response strategy for the energy industry involves improvements in demand and supply side efficiency, fuel substitution, removal of greenhouse gas emissions and research and development (see IPCC 1990).

The Commonwealth Government has adopted a conditional interim planning target of a 20 per cent reduction in Australia's greenhouse gas emissions by 2005, based on 1988 emissions. The Government's response strategy consists of a combination of international activity (eg the Commonwealth has supported the work of the IPCC and is a signatory to the Noordwijk Declaration on Atmospheric Pollution and Climate Change); a research program into causes, impacts and limitation and adaptation responses; public education; and a national strategy that will involve the Commonwealth, state, territory and local governments, industry and community groups (Prime Minister of Australia 1989). The Commonwealth stated that it 'will not proceed with measures which have net adverse economic impacts nationally or on Australia's trade competitiveness in the absence of similar action by major greenhouse gas producing countries.' The Government has requested the Industry Commission to report on `the costs and benefits for Australian industry of an international consensus in favor of a stabilisation of emissions of greenhouse gases not controlled by the Montreal Protocol on Ozone Depleting Substances'. That inquiry is required to report by 15 November 1991.

The Commonwealth's efforts to develop and coordinate a national strategy is being conducted through Commonwealth/State Ministerial Councils and the Ecologically Sustainable Development Working Groups. Some discussion papers have been released for public comment.

The response of the states to the greenhouse issue is also largely at the policy formulation stage: greenhouse Committees have been established; three states, Victoria, New South Wales and South Australia, have formally adopted the interim planning target of a 20 per cent reduction in carbon dioxide emissions by 2005; and discussion papers detailing potential response strategies have been released. Generally, proposed strategies have focused on a phased response with the initial initiatives consisting of those measures which have benefits other than for reducing the impact of climate change.

Energy conservation and improved efficiency in electricity generation are two areas which feature prominently in the proposed greenhouse response strategies. In a number of states, energy conservation programs have already been implemented.

11.5 Energy conservation

The Commonwealth's policy objectives with respect to energy conservation are twofold: first, to facilitate the efficient use of all forms of energy by overcoming those factors which inhibit market responses - for instance, external costs, information problems and the stringent criteria used for energy management investment decisions (DPIE 1988); second, to assist in minimising environmental damage caused by energy generation and use (Prime Minister of Australia 1989). These objectives are assessed in Chapter 10 and Appendix 12.

The framework developed by the Commonwealth to achieve these objectives emphasises measures which complement the market signals provided by energy prices, while minimising the use of regulation and financial incentives. A number of programs which concentrate on information, demonstration and technology transfer have been implemented by the Commonwealth. These include: the recent release, in conjunction with the Australian Consumers' Association, of a booklet on energy conservation options; the National Industrial Energy Management Scheme (NIEMS); the Commonwealth Energy Management Program (CEMP); the National Energy Research, Development and Demonstration Program (NERD&D); and the National Energy Management Program. This latter Program also involves the states.

Within the states, programs directed at energy conservation are at differing stages of development. The most extensive set of initiatives has been implemented in Victoria. The SECV is required by statute to implement the State's energy conservation goals and must advise and assist users in energy conservation, in particular in the efficient and effective use of electricity. A number of energy conservation activities have been included within the SECV's Demand Management Action Plan. Options include appliance labeling, building construction energy standards and the introduction of more efficient household light globes and other electrical appliances.

In Western Australia, SECWA is required to provide information on the relative efficiency, advantages and cost of differing methods of energy use. Programs implemented to meet these requirements include the promotion of natural gas and the energy labeling of appliances. Further commercially viable initiatives are being examined by SECWA's demand side management committee.

Recent energy conservation activities in Tasmania include the provision of information to households on efficient energy use, an energy conservation incentive scheme for schools, a pilot scheme for home insulation and a pilot scheme for the replacement of incandescent bulbs with compact fluorescent lamps on King Island.

In other states, demand side management and energy conservation activities are being developed:

- The Queensland Government stated that the ESI has developed a marketing strategy which recognises the industry's duty to advise customers on the efficient use of energy. Future objectives identified include better lighting efficiency, improved residential and commercial construction, and appliance standards. Other options were canvassed in the Queensland Government (1991) discussion paper on Energy Policy.

- The South Australian Government stated that elements of a demand management strategy were currently being implemented. A recent study indicated a greater potential for energy conservation initiatives than was previously thought possible.

- The New South Wales Government stated that there is a strong case for the ECNSW to implement demand management initiatives as a means of addressing market failures; for example, by the provision of information.

- The HECT has adopted DSM and recently initiated an energy efficiency campaign.

- In the Northern Territory, PAWA is examining the feasibility of load management initiatives and the Government is implementing an energy management program.

11.6 Renewable energy projects

At present, a number of governments (eg the Commonwealth, Queensland and New South Wales Governments), consider that the prospects for renewable energy technologies to replace large amounts of fossil fuels is limited by their current cost disadvantage. It has been argued that this cost disadvantage is partly due to the relatively low cost of conventional energy sources and to institutional impediments arising from distortions in the pricing and marketing of conventional energy resources (see DPIE 1988). These issues are examined in more detail in Chapter 10 and Appendix 11.

The Commonwealth considers that the growth in the use of renewable energy technologies can most effectively be achieved through market forces rather than by government intervention. Further, it considers that the most appropriate form of government assistance for renewables is through support for research and demonstration (DPIE 1988). This assistance is currently provided through the NERD&D Program.

Cooperation between the Commonwealth and the states on energy RD&D occurs through the AMEC Commonwealth/State Energy Research Liaison Committee.

This committee has provided advice on RD&D priorities and has promoted collaboration on projects of interest to more than one state.

Renewable energy currently contributes approximately 6.5 per cent of Australia's energy requirements. The most significant utilisation of renewable energy occurs in Tasmania, where practically all of that State's electricity is generated from hydro-electric sources. Other major renewable energy developments include the Snowy Mountains Hydro-Electric Scheme. The further utilisation of renewable technologies is largely limited to research and demonstration, for instance:

- SECWA has established a Renewable Energy Branch to assist in the understanding of renewable energy. It has also set up a wind farm at Esperence to supplement the local diesel powered electricity and has proposed the establishment of a wind park at Geraldton. SECWA is also investigating the installation of a much larger wind farm on the South West Grid system.

- HECT (1990) has negotiated with a Norwegian company to examine the feasibility of constructing a wave power plant to supply a considerable part of King Island's electrical energy requirements.

- In New South Wales, a generator is being developed utilising land-fill gas at Lucas Heights and ECNSW, in conjunction with the CSIRO, is examining optimal sites for wind farms. It is also supporting research into photovoltaics.

- In South Australia, Sagasco has contracted to introduce processed gas from Wingfield garbage dump into the Adelaide natural gas supply system (SAGASCO 1990);

- SECV has undertaken studies into the potential for wave and wind energy along the Victorian coast - a wind generator is currently in operation at Breamlea. Also, the viability of a wind farm in South Gippsland and small hydro projects throughout Victoria are being examined by private developers (SECV 1990).

- In Queensland, the potential of solar hot water for residential use has been examined and a significant amount of electricity is being produced in the State's sugar mills by the combustion of bagasse. The QEC (1987) has undertaken research at Birdsville to examine the potential for replacing power from a diesel generator with power generated from the town's bore water. It is also experimenting with solar photovoltaic/diesel hybrid systems in the Torres Strait and in Central Queensland.

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APPENDIX 12: DEMAND SIDE MANAGEMENT

Demand side management programs of governments and energy utilities consist of load management and energy conservation activities. Some of these activities have improved the efficient use of energy. However, there is a danger that without proper regard for the commercial objectives of utilities or the needs of energy users, these initiatives may reduce both the efficient supply of energy and the benefits derived from energy use. It must be established that a need exists for government intervention. Utilities should only be involved in those initiatives that are consistent with their commercial interests. It is the role of governments, through cost effective intervention, to ensure that any significant barriers to efficient energy use are removed..

12.1 Introduction

This appendix comments on the development of demand side management (DSM) programs and examines the role of the utilities, users and governments in seeking to alter the demand for energy. DSM measures can be broadly classified into two main categories:

- load management initiatives, which attempt to alter both the time of use (ie: move demand) and the need for peak plant; and
- energy conservation initiatives, which attempt to reduce the level of demand.

In the past, energy utilities have focussed primarily on supply-side solutions for balancing future supply and demand. Many of the current load management activities were implemented to reduce peaks and troughs in demand, permitting reductions in the system capacity required to meet demand and increasing plant utilisation.

Since the energy price rises of the early 1970s, the focus of energy utilities worldwide has tended to change. Increasingly, energy utilities and energy policy analysts have focussed on solving the energy requirements of consumers in the cheapest possible way. This approach, known as 'least cost planning', highlights the potential for improvements in the way energy is used; whether this be through, for example, the use of more energy efficient appliances or through passive solar designed buildings. This has focussed attention on the respective roles of users, utilities and governments in determining the pattern of energy use and has highlighted impediments to the efficient use of energy.

Energy utilities and governments in Australia have only recently become involved in the development of DSM programs. Parts of these programs have drawn upon existing activities, such as those related to load management. However, it is becoming more common for DSM activities to be directed at improving energy conservation and end use efficiency.

The following section outlines what constitutes DSM. Subsequent sections examine: potential savings that may be involved with implementing a DSM program (12.3); the relative role of users, utilities and governments in influencing energy use (12.4); and impediments to efficient energy use (12.5).

12.2 Demand side management - what is it?

Increasingly it is being recognised that gas and electricity are purchased not for their own sake, but because of the services they provide, eg lighting, warmth, motive power etc. Similarly, the role of the energy utility is changing. No longer are utilities viewed by all as being suppliers of gas and electricity at minimum cost, but more often as suppliers of energy services at least cost. This concept of least cost provision of energy services has extended utilities' interests into how energy is used and promoted the development of DSM programs.

Generally, DSM programs seek to influence the use of electricity or gas by improving load management and end use efficiency. Load management options attempt to improve an energy utility's supply efficiency by evening out fluctuations in daily, weekly and annual demand. Load management consists of initiatives which attempt to encourage load growth during off-peak periods ('valley filling') and shift demand from peak to off-peak periods ('peak clipping'). Load management can have the result of postponing the need to construct the next power plant. End-use efficiency initiatives attempt to reduce the overall level of demand. Except in the situation where there is over-capacity, end-use efficiency programs can reduce energy costs of consumers.

Some DSM activities have been undertaken by utilities for a number of years, such as off-peak tariffs and energy advisory services, while others such as energy conservation initiatives are more recent. A DSM activity will be commercially attractive for a utility if it can improve the utility's financial performance: that is, the activity enhances the utility's revenue or reduces its supply costs to a larger extent than it reduces revenue. Other DSM initiatives may improve community well being at the expense of a deterioration in the financial performance of a utility. For instance, the energy conservation strategy being developed by the Western Australian Government includes as one of its objectives the reduction in environmental damage through the use of energy (Western Australian Government 1990).

The differing views on what may be involved in a least cost approach to the provision of energy services is reflected in the various definitions of DSM, for instance:

- the New South Wales Government stated that DSM '... is often used to refer to all activities that change the shape or position of the load curve faced by the utility';

- the Western Australian Government defined DSM as 'programs designed to influence customer use of electricity in ways that will produce desired changes in the utility's load-shape'; and

- the South Australian Government stated that DSM '... refers to efforts by a utility to modify the level and demand for energy services by its customers'.

The various definitions do not specifically identify meeting customer needs as an objective. Furthermore, the definitions suggest somewhat different views as to what constitutes a DSM activity. The range of activities covered by existing and proposed State DSM activities are summarised in Table 12.1 and discussed in more detail in Attachment 12.1.

Table 12.1: **Overview of demand management programs by state/territory**[a]

	NSW	*Vic*	*Qld*	*SA*	*WA*	*Tas*	*ACT*	*NT*
LOAD MANAGEMENT								
• interruptibility clauses	*	*	*	*	*			*
• off-peak commercial tariffs	*	*	*	*	+			*
• off-peak residential tariffs		*	+	*	+		*	*
• off-peak hot water tariffs	*	*	*	*	*	*	*	
• off-peak space heating tariffs	*			*		*	*	
ENERGY CONSERVATION								
• government energy management program (GEMP)	*	*	*	*	+	*		*
• cogeneration		*	*	*	*	*		
• renewables	*	*	*	*		*		
• energy advisory services	*	*	*	*	*	*	*	
• promotion/sale of energy efficient products	*	*		*			*	
• residential audits/retrofit		*	*	+		*	*	
• rural/industrial energy audits		*	*	*		*		
• appliance energy labeling	*	*	+	*	*			
• residential appliance energy standards		+	+	+				
• residential construction energy standards		+	+		+			
• commercial construction energy standards		+	+					
• home energy rating scheme	*	+		+				
• energy efficient display homes	*	*	+	*	+	*	+	
• lighting - information/retrofit	*	*	+	+				
• air conditioning		+	+	+				

a * implemented policies
  + proposed policies

Source: Information supplied by State Governments and energy utilities.

12.3 Potential savings from demand side management

The DSM programs of all state and territory governments are in the formative stages, hence the associated savings have not been generally demonstrated. The South Australian Government claimed that the difficulty of quantifying the impact of DSM measures was a major impediment to its greater acceptance. The New South Wales Government considers that energy efficiency savings could represent a very significant proportion of future potential load.

A number of studies have attempted to assess the potential of DSM. In Queensland, it has been estimated that off-peak hot water arrangements have reduced winter evening peak loads by around 350 MW (about 10 per cent of peak load). In Victoria, it has been estimated that conservation initiatives have the potential to save 7 PJ of gas by 1995 and, by the year 2000, 4 PJ of electricity and 14 PJ of gas (DITR 1990).

A study of electricity demand in South Australia (Walsh, Crooks & Srinivasan 1990) indicated that by combining improvements in the efficiency of residential appliances, commercial lighting and industrial motors, with programs to increase the demand for off-peak hot water and domestic air conditioning, peak load capacity could be reduced by as much as 200 MW by 2007. The study also indicated that initiatives to improve end use efficiencies combined with a substantial program of industrial/commercial cogeneration could defer the need for a new base load power station until 2003. This is estimated to reduce total resource costs by $165 million (in 1990 Dollars).

An IEA (1989) study of electricity end use efficiency concluded that there is scope for electricity savings in the order of 10 to 20 per cent in all IEA countries. However, these savings could only be achieved over an extended period (twenty years or more) because major items of existing capital stock (eg industrial plant and buildings) would have to be replaced with more energy efficient units. Further, full realisation would require actions by governments to remove the various market and institutional impediments to improvements in end use efficiency.

A study by Greene (1990) was more optimistic. It estimated energy efficiency improvements and fuel substitution could produce energy savings, for Australia as a whole, in the order of 36 per cent by 2005. In current prices, this would represent an annual saving of over $6500 million in energy costs. The study estimates this would require investment in energy efficient technologies of only about one-third of the [marginal] cost of providing the energy which would otherwise be required.

The greatest potential savings were identified in the residential sector. In that sector, a 76 per cent reduction in electricity use for water heating and a 70 per cent reduction in electricity use for lighting were estimated to be feasible: these estimates were based on the assumption there will be an 80 per cent improvement in the efficiency of lighting and that 66 per cent of electric water heaters will be converted to solar, five per cent to gas and the remainder significantly improved.

In the commercial sector, the major savings were assumed to occur through more efficient lighting, heating, cooling and ventilating systems. Savings in the manufacturing sector were linked to increased cogeneration capacity and more efficient motor drives.

12.4 Role of users, utilities and governments in demand side management

Much of the discussion about DSM does not address the role of the different players in the energy market. The subsequent discussion seeks to address a number of questions relating to the role of users, utilities and governments in energy use. These include: Should the issue of end-use efficiency be left to the energy user who might be expected to have a clear financial interest in reducing inefficiencies in use? Does DSM make sense from a utility's point of view? Why would a utility involved in selling electricity or gas wish to reduce its sales? Where, if at all, do governments fit in?

12.4.1 Role of energy users in demand side management

Energy users have an incentive to alter their pattern of energy consumption to increase disposable income, in the case of households, or profitability in the case of a firm. The strength of the incentive will differ between users reflecting differences in the perceived net benefits associated with either altering the time at which energy is used or improving energy efficiency.

For the domestic consumer, the incentive for improving energy efficiency may be significantly lower than for an industrial user. First, electricity and gas represent only a small proportion - 3 per cent on average (ABS 1990) - of a household's budget. Second, the purchase of an electric or gas appliance depends not only on the initial purchase price and running costs, but also on other factors such as personal taste, ease of installation and the value of existing appliances. The incentive for a household to minimise energy costs is limited by these other influences, as well as by the fact that any potential savings may be perceived as being relatively small.

For industry generally, electricity and gas also represent a relatively small proportion of total costs. However, this is by no means the case for all industries. CRA stated that electricity represents 30 per cent of the operating costs of an aluminum smelter and ICI claimed that electricity contributes 64 per cent of the variable costs of producing caustic soda. Therefore the incentive for energy intensive industries to be energy efficient is quite substantial. Many of the potential gains may have already been realised. For instance, the Greene (1990) study assessed the potential for further significant reductions in electricity use in electrolytic processing as 'limited in the short/medium term'.

The establishment of a market which advises on the potential for efficiency improvements is also indicative of the significance placed by industry on reducing energy costs.

Correct pricing signals from the electricity and gas utilities are an essential prerequisite for the efficient consumption of energy. These signals inform users of the costs associated with the production of a particular energy source. This allows the user to examine the options to either conserve energy, use it during less costly periods or choose an alternate energy source. However, as discussed in Section 12.5, cost reflective prices may be insufficient to ensure the efficient use of energy.

12.4.2 Role of energy utilities in demand side management

Price signals are also important for utilities. For example, if prices are 'too low', demand will be greater than it would otherwise be. This additional demand will signal the need for an expansion in capital which would not be necessary if correct prices applied. Therefore, prices and pricing policies form important elements of utilities' DSM programs.

It is frequently argued that DSM provides benefits which could not be achieved solely through the development of supply side initiatives. The IEA (1987 & 1989) summarised these as including:

- a higher return gained on investments in energy conserving technologies than in energy supply;

- improved flexibility as investment in energy conservation, in contrast to extensions to capacity, can often be undertaken in small increments with short lead times; and

- in the case of electricity utilities, reduced generating costs through reductions in the need for standby capacity used primarily to meet peak demand.

The realisation by a utility of potential savings from implementing a DSM program requires that the benefits exceed the program's costs. Just as the characteristics of utilities and their markets differ, the relationship between benefits and costs will also differ between electricity and gas authorities, and also between different utilities. Therefore, the range of DSM activities implemented will differ between utilities.

For some utilities, DSM activities may offer a more cost effective mechanism for reducing production costs than would some supply side developments. For instance, electricity utilities commonly offer rebates to induce some large users to accept interruptibility clauses in their supply contracts. The reduction in the utility's revenue is more than offset by the savings induced by avoiding the need to install additional peaking plant.

Load management initiatives are not as important for some gas utilities as they are for the electricity industry generally. This reflects, first, the present balance between supply capacity and demand and, second, the fact that gas, unlike electricity, can be stored. For example, AGL stated that the supply costs for gas in New South Wales do not vary significantly throughout the day as the distribution system is not operating at full capacity, hence there are no peaking constraints. Moreover, if peaks occur they can be met from the storage capacity inherent in the gas transmission and reticulation systems or from dedicated storage's. Nevertheless, it can be expected that the demand for gas in New South Wales will grow and that the load will become 'peakier'. The Pipeline Authority stated that, in these circumstances, greater differentials in the supply costs will arise, although they will largely be restricted to compressor fuel and maintenance costs.

Meeting peak demand is more of a problem for gas distributors in Victoria and South Australia where the transmission line is required to be operated at close to full capacity to cope with peak demand. In these states, interruptibility clauses have been negotiated in the supply contracts for some major customers.

Similarly, restricted opportunities exist for load management of electricity supply in Tasmania. The Tasmanian Government stated that opportunities for applying time-of-use pricing are limited because of the lower differences between peak and off-peak supply costs associated with a largely hydro-electric system.

In a competitive environment, commercial incentives would exist for utilities to engage in activities which assist the consumer to conserve energy, such as energy advisory services and home audits. These services provide information about the efficient use of energy and may result in advice which reduces, in the short term, a consumer's energy needs. A utility may elect to provide these services to maintain sales in the longer term by ensuring that users do not switch to a lower cost energy source. For example, AGL stated that the gas utilities have been actively involved in the development and promotion of efficient gas appliances and in the labeling of gas hot water heaters and space heaters in order to secure market share against other energy sources. In many respects, the energy conservation activities of a utility are similar to the pre- and after-sales services offered by many of the retailers of other goods.

Currently, there is little competition between energy suppliers. Governments have, however, introduced regulations requiring the provision of advisory services. For example:

- SECV is required to implement the Victorian Government's energy conservation goals and must advise and assist customers in energy conservation, in particular in the efficient and effective use of electricity; and

- SECWA is required to provide information on the relative efficiency, advantages and cost of differing methods of energy use.

In the United States, the state governments and regulatory commissions have also been instrumental in the development of DSM initiatives, and the associated Least Cost Planning (LCP) strategies, by the energy utilities. A report by the Electric Power Research Institute (1988) stated that:

> At least 17 states have functional LCP strategies. Commissions in many of these states enforce least-cost planning through a variety of regulations and filing requirements, often using plant authorization or rate cases as the forum. Legislatures in at least 12 of these states have supported the process either by passing LCP laws or by giving authority to the commissions to establish and enforce regulations. Utilities in a few of these states practice LCP without regulatory or legislative mandates.
>
> An additional 8 states are beginning to implement LCP strategies through legislative, regulatory, or utility action. Regulatory planners are developing or actively considering LCP in 18 more states.

12.4.3 Role of governments in demand side management

Governments have traditionally been deeply involved in many facets of the operations of energy utilities. While their actions have not, for the most part, been directed at changing levels or patterns of energy use, they have affected energy prices and, as a consequence, the incentives for energy use. For instance, tax exemptions provide public utilities with a commercial advantage over their private sector counterparts, whether they be a privately owned gas utility or manufacturer of solar hot water systems.

A number of participants maintained that governments should become directly involved in influencing energy use. Some contended that governments should intervene in the market place itself and/or impose specific requirements on the activities of the utilities to address factors which hinder consumers from making decisions which lead to more efficient energy use. For example, some contend that inadequate information on the relative efficiency of the various energy appliances acts as a barrier to more efficient energy use. The imposition of energy labeling requirements and minimum energy efficiency standards for appliances has been viewed as one solution to the problem.

In its submission to this inquiry, the Rainforest Conservation Society argued for the introduction of policies to improve the efficiency with which energy is used. It stated that, to reduce the environmental impact associated with the generation and distribution of energy, utilities should engage in DSM activities directed at energy conservation.

12.4.4 Assessment of the roles of users, utilities and governments

The Commission concurs with the view that, since the consumer is the one who benefits from the use of energy, the consumer should be in the best position to judge which pattern of energy use maximises these benefits. Hence, the primary responsibility for determining the pattern of energy use must reside with the consumer, whether this be a household or a business.

As utilities and the community at large bear the cost of providing energy, a role also exists for utilities and governments to influence the way in which energy is used. Though, if this role is not limited in some way, governments run the risk of diminishing the benefits users receive from the energy supplied. The appropriate role for utilities and governments is to provide energy users with the correct signals on the relative cost of energy services from alternate sources. DSM activities can facilitate this by ensuring that energy prices accurately reflect supply costs (including environment costs) and by removing any institutional or market impediments to the efficient use of energy.

A DSM program should be implemented if it provides clear benefits to society by reducing the cost of meeting the energy needs of users. Some DSM activities will be commercially attractive to energy utilities because supply costs are reduced, the utility receives payment for the service, or market share is maintained. However, other DSM initiatives may be commercially unattractive for a utility because sales are reduced without any of these benefits.

If energy utilities are required to implement a DSM initiative from this latter category, a conflict arises between the utility's commercial objectives and the DSM program objectives of ensuring that users are provided with energy at minimum cost. By blurring a utility's responsibilities in this way, it is inevitable that a tradeoff will be made between these objectives. This will detract from the utility's ability to supply energy at minimum cost and will limit the effectiveness of initiatives designed to reduce society's costs of consuming energy services.

To ensure the effectiveness of any DSM initiative, a clear distinction needs to be drawn between those initiatives which are implemented by utilities and those implemented by some other government agency. In defining roles for utilities and governments:

- The Queensland Government stated that it is `entirely appropriate for the gas and electricity supply authorities to attempt to influence the pattern of demand for their product with a view to reducing the need for capital expenditure to supply peak loads, and to promote the use of more efficient appliances and energy efficient building designs where doing so is in their economic interests. With respect to energy conservation, it is the role of governments to initiate policy within which the supply authorities work'.

- The SECV argued that, while some programs may provide a clear benefit to the SECV, there are others that may not, but will improve society's position. The SECV suggested that these latter programs could be treated either as CSOs with their costs/benefits separately identified, or be provided by a commercial energy service company receiving income from the Government for the services provided.

Energy utilities should only engage in those demand side management activities in which they have a commercial interest, such as load management and advisory services. The appropriate role for governments in demand side management is, first, to remove any institutional impediments to ensure that utilities are able to respond to the commercial incentives for the provision of energy services and, second, to address any significant market failures which limit the efficient use of energy.

By clearly defining the relative roles of utilities and governments in this way, users will be best able to choose that pattern of energy demand which maximises the benefits received from energy consumption.

12.5 Institutional impediments and/or market failures

This section seeks to assess whether a number of suggested institutional impediments and/or market failures actually apply in practice and, if so, whether the intervention often advocated is able to effectively address the source of the problem. Institutional impediments and market failures are dealt with separately.

12.5.1 Institutional impediments

The institutional impediments perceived to impair the efficient use of energy are related to the pricing and metering policies of the energy utilities and to the regulations controlling the industry which results in restricted competition between energy sources.

Pricing policies

Recent studies have identified deficiencies in the pricing policies of energy utilities. These have detracted from effective load management and given the wrong signals to users about supply costs. These issues are discussed in Chapter 9. The broad conclusion from that discussion was that the prices charged for electricity and gas do not closely reflect the economic cost of supply.

In its submission to this inquiry, the New South Wales Government recognised that for DSM programs 'to be fully effective, it would be necessary to have a time-of-use marginal cost based retail tariff'. A recent report by the IEA (1989) concluded that electricity prices and related metering practices have the broadest and most influence on electricity end use efficiency of any government or utility action. This is also true for gas. The rationale is that the price of energy is the basis on which users judge the cost effectiveness of either an investment in an energy efficient appliance or in an alteration to their pattern of energy use. If the price of gas or electricity is below its economic cost of production (including any environment costs), consumers will have less incentive both to purchase an energy efficient appliance and to adopt energy efficient practices (eg use cold rather than hot water to wash clothes). Incentives for firms to engage in the research, development and manufacture of energy efficient appliances will also be diminished.

A contributing factor has been the institutional impediments which have inhibited prices from reflecting the economic costs of supply. These impediments consist of a range of regulations and government policies which govern the operation of the electricity and gas supply industries. These include the use of energy prices to stimulate economic activity, imposition of taxation arrangements which give preferential treatment to public utilities and stipulation of uniform pricing.

Renewable energy technologies should be most competitive with energy from traditional sources in remote areas which are costly for utilities to supply. Yet the use of these technologies has been limited by subsidisation of extensions to the transmission network. For some consumers, such as domestic and rural users, tariffs are generally subsidised by other users, such as commercial and industrial. This creates differing incentives for users to conserve energy. SECV estimates of the benefits for commercial users from non-price DSM activities was largely attributed to these cross-subsidies (SECV/DITR 1989a). For the same reason, the incentive for domestic users to conserve energy would be much lower.

It is essential that governments recognise the present policy contradictions: in particular, that government involvement in the operations of public utilities has distorted energy prices. In turn, this impacts adversely on the incentive for the use of renewable energy and energy conservation.

Time-of-use pricing policies have largely been employed by utilities to even out load, increase capacity utilisation and reduce supply costs. More appropriately, the intention of time-of-use pricing should be to make charges more reflective of costs. In some cases, this divergence in objectives for time-of-use pricing has resulted in a number of deficiencies. First, time-of-use prices are limited to only a few end users or end uses (eg large customers or residential hot water). Second, the differentiation that does occur is limited to only two or three rates. Third, the price differential between the peak and off peak periods does not fully reflect the differences in the cost of supplying consumers at the differing periods of the day.

An essential part of any DSM program is to ensure that energy prices closely reflect the economic costs of supply. This provides users with the correct incentive to conserve energy and places on an equal footing the various energy technologies, such as electricity, gas and renewable energy.

An approach which maintains the current inefficient pricing structures and attempts to compensate for the inefficiencies which ensue is likely to be administratively costly. It is also likely that such an approach would leave some problems unsolved; for instance, subsidisation of efficient appliances to compensate for subsidised domestic energy prices will not encourage the adoption of energy conserving behavior. In addition, other distortions may be created if the subsidy is not paid on the basis of the energy efficiency of the appliance.

Another related issue concerns the metering and billing practices of utilities. The IEA (1987) stated that the incentive for energy conservation is limited by the 'invisibility of energy consumption'. That is, by periodically billing consumers for energy which is used continually the costs associated with energy use are masked.

Since it is costly to read meters and bill consumers, it is sensible for utilities to do this periodically rather than continuously. On the other hand, periodic billing involves the sale of energy on credit thus, to minimise the amount it is owed, a utility would want to bill consumers as often as possible. The billing period chosen will reflect the tradeoff between these two costs. The length of a billing period may fall as technological change makes meter reading and billing a much simpler process.

Also, residential consumers are unable to obtain any direct price signals reflecting the energy use of individual appliances. Metering practices which provide information on the energy consumption of major appliances are costly. Information on the efficiency of certain appliances or on energy conserving habits may be less costly. This issue is discussed in greater detail below. The costs of these alternatives need to be balanced against the expected benefits in deciding which, if any, are to be implemented.

Limited competition

In Section 12.4.2 it was argued that in a competitive environment utilities have a commercial incentive to provide energy advisory services to maintain market share. However, energy utilities currently operate within a heavily regulated environment. One effect is that options for most consumers to purchase energy services is limited to one, or two, suppliers. Therefore, the energy market is unlike other markets where consumers dissatisfied with the services of one supplier can choose to do business with a competitor. Such options force firms to compete with each other to provide the services demanded by consumers at minimum cost. These competitive forces presently exist in energy markets in a limited number of circumstances; for example, in some locations hot water can be fuelled by either solar, electricity or gas.

Consumers may also seek advice from appliance manufacturers, retailers or, in more complex circumstances, from professional independent advisers. Recourse to this latter alternative is reflected in the growth in the number of consultancies which provide energy advice.

In the absence of effective competition in most market segments, some contend that there should be regulations requiring utilities to undertake load management and energy conservation initiatives. If the proposals recommended throughout this report to make utilities more competitive are adopted, the utilities should have the incentive to undertake a range of DSM activities. Consequently, it is unlikely that there would be a need for the type of regulation proposed. In a more commercial environment, utilities themselves would consider the provision of DSM activities which are commercially attractive to them.

This is a process which has occurred in the United States where increased competition came from third-party power suppliers, neighboring utilities and more efficient end use technologies. The competition focussed on key profitable markets and niches where customer needs were unsatisfied.

The utilities, in response, re-examined the services offered through value based planning techniques; it was recognised that a focus upon cost alone may not provide desirable results. Utilities attempted to identify the services most valued by customers and developed options to meet these needs. Some of these options focussed on varying the reliability of service to customers, either for a specific end use (eg air conditioner cycling programs) or for a general class of reliability (eg opting for a first rotating outage block) - for a further discussion of these developments see Geller (1988).

12.5.2 Market failures

Submissions from the Australian Conservation Foundation and the Rainforest Conservation Society maintained that other impediments or non-technical barriers exist which limit the efficient use of energy. The same impediments have been referred to in the context of wider studies of end use efficiency in various overseas countries (see for example IEA 1987). These include:

- non-inclusion of environment costs;
- lack of information;
- landlord/tenant problem;
- new technology; and
- access to capital.

Each of these suggested impediments is discussed below, along with an assessment of the nature of the impediment and its effect on end-use efficiency. Ways in which avoidable inefficiencies might be addressed are also discussed.

Environment costs

It has been argued that the supply and use of some types of energy has a number of adverse effects on the environment. One option often suggested to overcome or limit this impact has been for governments to actively encourage energy conservation.

Environmental impacts differ between the energy supply option chosen. For example, many scientists and environmentalists have expressed concern over the burning of fossil fuels resulting in the emission of carbon dioxide, a 'greenhouse gas'. The amount of carbon dioxide released per unit of energy varies between fossil fuels (eg brown coal, black coal or gas) and, in the case of electricity, between generation technologies (eg pressurised fluidised bed combustion for coal or combined cycle for gas). Other environmental effects occur through the use of renewable energy technologies. Hydro-electric projects, such as the proposed Tully-Millstream development, impact upon natural ecosystems, while preferred sites for wind farms may be areas of scenic beauty.

If energy prices do not reflecting all production costs, such as environment costs, energy will tend to be under-priced. This will result in excess consumption. Energy conservation technologies can also have environmental implications. For example, double glazing of buildings has been advocated as a way of conserving energy. Yet the production of glass is a relatively energy intensive process. It may be the case that other, less energy intensive, conservation options would have a greater impact on reducing total energy consumption. Thus, encouragement of energy conservation may not solve all of the problems associated with the environmental effects of energy supply.

Another option to limit the environmental impact of energy supply, and one currently used in Australia, is to compensate for and/or minimise some of the environmental effects through a range of standards and regulations. However, these requirements, which are outlined in Appendix 11, may not include all of the environmental impacts and may not achieve environmental goals in a least cost fashion.

For example, governments in the United States have acted to reduce emissions of sulphur dioxide. The New Source Performance Standards of the Clean Air Act of 1977, was amended by:

> ... requiring strict application of "best available technology" for new coal-fired generating plants. Instead of setting specific emission standards and allowing plants to meet them by using cleaner, low-sulphur western coal, owners of generating facilities were forced to install stack-gas scrubbers, which cost more to buy and operate (Anderson 1991, p. 156).

Since monitoring the efficiency of the scrubbers was costly, there was an increase in the cost of installing new plant and a decrease 'in the rate of replacement of older, dirty utility boilers'. It has been estimated that standards to reduce sulphur dioxide emissions will have increased electricity production costs by $US4.8 billion by 1995 (Anderson 1991 p. 156), and increased emission rates by 27 per cent 'because of the effects of regulation on the age of capital' (Maloney and Brady 1988, p. 224).

It has often been argued that to reduce compliance costs of meeting environmental goals more flexible methods, such as tradable emission rights and pollution taxes, should be used. In general, tradable emission rights schemes operate with the environment regulatory authority setting, on a regional basis, allowable limits on harmful emissions. Polluters then vie for the right to emit the allowable pollutants within the regional limit.

To meet the regional limit, the utility would choose the option which minimises the pollution control costs. Most likely this would involve a mix of installing pollution abatement equipment, altering the production technologies and fuels used, and paying for the emission right. The greatest share of emission reductions will occur in those places where pollution abatement is relatively costless. For instance, other things being equal, it would be most productive for emission control costs to be borne by power stations whose remaining economic life is relatively long, as an investment in pollution abatement equipment can be 'paid back' over a longer period of time. On the other hand, payment for an emission right may be the least cost option for a power station with a relatively short economic life.

The gains from these programs derive from the detailed knowledge the industry, not the regulators, possess on mechanisms to reduce environmental impact.

A number of schemes, with varying levels of success, have operated in the United States during the 1980s. These include: netting, which allow firms to offset new sources of emissions by reducing emissions within the same plant; offsets, which allow emissions from new sources to be balanced by reductions in existing emissions (either from within the plant or from another plant); bubbles, which allow emissions from existing sources to increase by reducing emissions elsewhere; and banking, which allow firms to save emission reduction credits for future use in emission trading. Hahn and Hester (1987) estimated that, since their inception, compliance costs had been reduced by $US4 billion through netting arrangements and by $US435 million through bubbles. These benefits could be further enhanced through improvements in existing arrangements.

If a particular emission is viewed as harmful, governments should consider either imposing a pollution tax, tradable emission right, or performance-based standards in preference to a more rigid prescriptive standard. This would provide utilities with the option to choose a production technique to comply with emission controls in the most efficient (least cost) manner.

This will involve a choice between the use of coal, gas or some form of renewable energy. It will also encourage the utilities to develop and adopt new technologies which minimise the environmental effect of supplying energy.

The technique chosen will be the most cost effective of the options available, although an increase in supply costs and energy prices could be expected. This price rise would, in turn, induce increased energy conservation. While a DSM control may be able to encourage an optimal level of energy consumption, it may not achieve this in a least cost fashion. Options directed at reducing the level of consumption offer no incentive for the utility to adopt more 'environmentally friendly' production techniques.

Lack of information

Incentives for users to conserve energy may be limited by a lack of information on the relative efficiency of appliances and/or because of deficiencies in available information. Consumers choosing between a range of electrical/gas appliances will typically be well informed about a number of features, such as price, but will be relatively uninformed about other features such as running costs. Purchase decisions will therefore be based on the features they know about and there may be a tendency for consumers to purchase less efficient appliances. Similarly, if consumers tend to be more sensitive to purchase prices than running costs, appliance manufacturers will have a disincentive to invest in the production of relatively higher priced energy efficient appliances.

The tendency for consumers to purchase less efficient appliances will be influenced by the costs associated with acquiring information on running costs, relative to the savings from using a more efficient appliance. Studies of consumer behavior indicate that consumers are more likely to purchase an energy efficient air conditioner or space heater than they are to purchase an energy efficient refrigerator or freezer (see Train 1985 and Ruderman 1987).

Consumers purchase many products about which they know very little, either because the information is costly, or it is difficult to understand. Market based mechanisms have developed to help overcome such information deficiencies. For example, as businesses experience increased pressure to reduce costs, they are increasingly investigating ways to cut energy costs. Firms that specialise in performing energy audits have developed to fill this 'gap'. Instead of charging clients directly for energy audits and retrofits, it is becoming more common for energy consultants to provide these services at no cost to the client. The consultant receives payment for these services by contracting with the client to share in the savings achieved through reduced energy bills. In this way, the risks associated with energy efficiency investments are borne by the party which has a greater understanding of the technologies involved - ie the risks are transferred from the customer to the consultant. These arrangements are similar to those that an author may agree on with a publisher in order to share in the profits from the sale of a successful book.

In addition, manufacturers of energy efficient appliances will provide information where the cost of doing so reduces consumers costs of searching for the information, or where it enhances their reputation. As consumers are unlikely to know how accurate the information is, general consumer protection legislation and industry codes of conduct have developed to control product claims and protect consumers from unscrupulous dealers.

Since different products possess different features, it is argued that general requirements may not be enough and that specific minimum performance standards and labeling requirements need to be developed for different products. The underlying rationale is that, because manufacturers are in the best position to know the features of their product, it is less costly to require manufacturers to accurately describe their products than to have a large number of customers searching for the same information. Similarly, because manufacturers are in the best position to influence a product's performance, it is contended that they should be required to ensure that products conform to some minimum standard rather than allowing competitive forces to reduce manufacturing costs at the expense of the energy efficiency of the product.

Minimum performance standards currently apply to a wide range of goods and services. They are intended to protect the health and safety of the community. This approach has been adopted since it is difficult, if not impossible, to compensate people who are caused physical harm from using a product. The implicit judgement is that society benefits from preventing injury rather than from attempting to cure it once it has occurred. Even these approaches have, however, recognised the cost associated with regulatory intervention (for a discussion of these issues in relation to food see IAC 1989a and 1989b).

In the context of energy efficiency, some utilities and state governments have adopted energy labeling for electrical and gas appliances, as well as home energy ratings schemes; energy efficient display homes have also been used to demonstrate the savings associated with energy conservation. Minimum efficiency standards have also been advocated for appliances, as well as for residential and commercial buildings. It is argued that the community's awareness of energy efficiency will be heightened and that the least energy efficient appliances and building practices will be removed from the market.

However, minimum energy efficiency requirements often involve costs which are difficult to assess, not borne by the regulators, and which are often ignored in establishing labeling and minimum performance requirements. These indirect costs include manufacturers' compliance costs and costs which stem from any reductions in the choice available for consumers.

Reduced consumer choice can occur for a number of reasons. First, in developing efficiency standards, regulators will be required to assess what constitutes an inefficient appliance. In making this judgement, regulators often seek the expertise or views of interested parties, such as technical experts, manufacturers and community groups. However, there is no guarantee that the advice provided will be independent nor represent all sectors of the community. For instance, existing manufacturers may attempt to use this forum to erect entry barriers to competitors in order to protect their market share. Also, the consultative process is usually lengthy which can delay, if not discourage altogether, the introduction of new or innovative products.

Second, a minimum efficiency standard can ban from the market a consumers' preferred choice. For example, a consumer may prefer a heating appliance for an infrequently used room, for example bathroom, which is less efficient in comparison to that which heats the main living areas of their home. This may occur because the heating costs for the bathroom will be minimised through the purchase of a heater which has a low capital cost, though high running costs. Similarly, less efficient heaters may be preferred in other circumstances where they are infrequently used, for example, in temperate climates when a heater is only required on a small number of days a year.

A study by Morss (1989) concluded that losses from minimum efficiency standards will be:

> concentrated among households with low incomes, small numbers of persons, and small-sized dwellings (these households will be the most likely to prefer low levels of efficiency). This would include various disadvantaged groups within the population, as well as most of the aged. These households more than others will be confronted with the unpleasant choice of paying for a more efficient appliance than they would wish, or doing without the appliance altogether.
>
> Regionally, welfare losses due to national appliance efficiency standards will be chiefly felt in those areas where the price of electricity is low, and (with respect to heating and cooling standards) the climate is mild.

Prior to the implementation of programs intended to rectify problems caused by a lack of information, such as energy labeling and more particularly efficiency standards, it needs to be clearly established that these programs are capable of providing net benefits to society. This assessment should include estimates of both direct and indirect costs.

Landlord/tenant problem

The Rainforest Conservation Society and the IEA (1987) argued that energy conserving features, such as solar hot water or ceiling insulation, are less likely to be built into rented accommodation than into owner occupied buildings. This occurs if the landlord is unable to receive sufficient benefit, in the form of higher rents or resale prices, to compensate for the cost involved. In turn, tenants are unlikely to make these investments unless the investment will pay for itself over the lifetime of the tenancy.

A similar problem exists in some owner occupied buildings. An owner will have a reduced incentive to invest in energy conserving features if these features are unlikely to be recognised when the building is sold; that is, if the improvements are not capitalised into the value of the building. In this case, an owner will only invest in those features that are likely to repay themselves over the remaining duration of their occupancy. These problems are similar to those discussed in the previous section. However, in this case, instead of consumers having a lack of information on the efficiency of an appliance, the information problem relates to the purchase and rental of buildings.

A number of studies have examined the ability of housing markets to capitalise investments in energy efficiency into building prices. The evidence is somewhat contradictory. For example:

- the value of fuel savings are capitalised, remarkably well, into house prices in Knoxville, Tennessee - at a discount rate of 9 per cent (Johnson and Kaserman 1983); and

- other studies suggest that housing markets capitalise improvements in the thermal integrity of buildings at discount rates between 10 percent, for window and door measures, and 30 per cent for thermal shell measures (for a survey of these studies see Train 1985) .

Studies such as these have been used in support of claims for governments to assist the provision of information through mechanisms such as audits, energy ratings and minimum efficiency standards for buildings. In Australia, most utilities offer advisory services (some of which include audits); a rating scheme has operated in some states with limited success; and, more recently, energy standards have been proposed in Victoria for new residential and commercial constructions.

Overseas, the experience with building energy efficiency information programs has been much broader. Studies have indicated that, where government programs emphasise information provision, the housing market can efficiently capitalise the value of investments in energy conservation (Laquatra 1986). Further, this information has proved valuable for prospective home buyers, by reducing the search costs in finding a new home (Gilmer 1989).

The emphasis in many of these schemes has been on the provision of information. A utility in the United States implemented a voluntary scheme whereby they conducted energy audits of apartments. Audit results were published in a booklet, along with advertisements by apartment owners, and distributed amongst prospective renters, eg university students (Anderson 1988). In Denmark, a heat survey scheme required all dwellings sold to have either a certificate saying the building met thermal integrity standards or have a report stating the cost of meeting the standard (Brown 1988).

Initiatives such as minimum efficiency standards focus not so much on providing information, but rather on banning energy inefficient building practices. Like appliance standards, these initiatives involve indirect costs which would be reduced if the proposed standards were flexible enough to allow for the introduction of new technology and for differing environmental conditions - for example, the design features of an energy efficient building would differ between North Queensland and Coober Pedy.

New technology

The IEA (1987) stated that the incentives for private industry to undertake research and development into energy conservation through either new construction techniques or new energy efficient appliances are inadequate. This is attributed to:

- the competitive nature of the building industry where no single firm can afford the expense of a research and development program and, even where a new technique is developed, a company cannot earn a return on the investment since they are unable to prevent other firms from using the technique; and

- the high risk associated with the development of new technologies.

Governments have attempted to reduce the disincentives for investment in developing energy efficient technologies and building practices through tax concessions and grants for private investment in research and development (R&D). In other industries governments have established statutory authorities to impose levies on all producers to provide funds for an industry based R&D program.

However, the perception of inadequate incentives for private R&D is common to a large range of industries which have not received government support through a specific R&D program. To overcome these problems, many firms utilise the patents system to ensure a return on the investment in the development of a new technology. In circumstances where patent rules do not apply, a return on the R&D investment is earned through the competitive advantage a new product or technique provides. This advantage may only apply for limited period during which competitors 'catch up'.

On balance, there may be a case for government support for specific grants to assist research and development into energy efficient and renewable energy technologies. However, the extent and allocation of funding must be based on the establishment of program specific objectives and evaluation criteria.

Access to capital

The Australian Conservation Foundation and the IEA (1987) have argued that it is often difficult for domestic consumers to gain access to capital to finance an investment in energy conservation. On the other hand, utilities have been given favorable treatment in accessing capital for the purpose of increasing supply. It is argued that to put supply expansion on an equal footing with end use efficiency, electricity authorities should provide, or a separate fund should be established to provide, finance for a range of energy services such as heating and insulation.

Elsewhere in this report, the Commission has argued that public utilities be corporatised, thereby removing any unfair advantages they posses over private sector suppliers of energy services (eg gas utilities and suppliers of thermal insulation and solar heating technology) and users; this includes removing public utilities' access to concessional finance.

The Commission has also discussed a range of mechanisms open to governments and utilities to facilitate the provision of information on options to improve the efficient use of energy. Some of these mechanisms, such as appliance energy labeling and building energy rating schemes, make it easier to assess the value of investments in energy efficiency. Some studies of home energy rating schemes in the United States indicate that:

> ... lending institutions are increasingly willing to use ratings as a basis for adding retrofit costs to a mortgage loan and for qualifying marginal borrowers who purchase efficient homes (American Council for an Energy Efficient Economy 1984, p. 49).

If further problems exist with access to capital for energy conserving investments, it is likely the problems are broader and include consumer access to finance in general.

Such problems are not directly related to energy utilities or energy markets and would need to be examined in the context of access to finance for other borrowers; such as industry and governments.

12.6 Summary

In this appendix, the Commission has argued that the DSM programs of energy utilities should focus on identifying and meeting the needs of energy consumers by adopting pricing policies which reflect more accurately underlying supply cost (including environment costs). Governments should remove any institutional impediments to ensure that utilities are able to respond to the commercial incentives for the provision of energy services.

Governments should also address any significant market failures which limit the efficient use of energy. To ensure the net benefit from intervention is maximised, government programs should emphasise information provision and flexibility in the responses of utilities and energy users; for example, transferable emission rights and taxes to limit possible environmental effects associated with energy supply, and information programs, advisory services and labeling requirements to improve efficient energy use. Limited use should be made of measures which restrict the ability of utilities to minimise supply costs and consumers to maximise the benefits received from their disposable income; for example, prescriptive environmental standards and mandatory minimum efficiency standards for appliances and buildings. All measures implemented should be cost effective.

Attachment 12.1: Government responses to impediments and/or market failures

The Commonwealth Government provides coordinating functions and administers and funds a grants program for R&D into energy efficiency improvements. However, DSM activities are primarily the responsibility of the state governments and state-based utilities. The full range of activities covered by existing and proposed State DSM programs are summarised in Table 12.1. The measures which have been adopted differ between the states/territories and between the gas and electricity utilities. Moreover, it is only in more recent times that attempts have been made to draw these initiatives together to form integrated demand management programs. While the development of such programs are much further advanced in some states (eg Victoria) than in others, all remain largely at the policy formulation stage. The following sections describe the development of DSM programs in the various states and detail the activities that have been included.

A12.1.1 State energy demand management programs

An energy conservation program has been under development in Victoria since the late 1970s. Early initiatives included advisory services and the Government Energy Management Program. The NREC (1988) report recommended the continuation of these programs. It also recommended that the SECV: give consideration to expanding its range of electricity supply tariffs to include more generally available tariffs for controllable or interruptible supplies; and that it investigate the potential to expand existing programs and to develop new conservation and demand side measures.

Further investigations were undertaken by the SECV/DITR Demand Management Development Project. This study (SECV/DITR 1990) argued that even though DSM shows large potential, uncertainties remain; both in terms of the cost effectiveness of the various options and in their ability to balance future electricity supply and demand. In response to these uncertainties, the SECV/DITR have initiated a $55 million, 3 Year Demand Management Action Plan. This Plan is expected to facilitate the further development of DSM initiatives and enable the SECV to respond flexibly to Victoria's energy needs.

The DITR and the GFCV are also examining demand management options for the gas industry. This examination includes investigations into the potential for peak demand reduction, load shifting and efficiency improvements in gas use.

In the other states, the development of a demand management program is not as advanced as in Victoria.

- In Queensland, existing demand management initiatives aim to reduce peak loads by demand shifting. A number of energy conservation options have been identified for the future.
- Further demand management options are being examined in the Green Paper on Energy Policy and by the Tully-Millstream Task Force.

- In Western Australia, an examination has been undertaken into the potential for a formal demand management program for SECWA which is expected to be released later this year.
- In South Australia, limited work has been done into DSM activities, although a recent report indicated that a number of demand management measures could be cost effective.
- In New South Wales, a demand management program is being developed with a number of specific options being further researched.

A12.1.2 Demand side management initiatives

The main elements of the Commonwealth, State and Territory demand management programs are briefly discussed in the following sections.

Pricing

It is widely recognised that pricing policies are an important part of any DSM program. The ECNSW stated that while 'non-price inducements may play a role, price is a major factor in virtually all demand side programs' (ECNSW 1989). Pricing initiatives were included in the range of DSM activities originally considered for evaluation in the SECV/DITR demand management development project. However:

> The Project team ruled out the use of electricity price increases per se as a means of suppressing electricity demand in accordance with Government Policy which views electricity pricing as a key means of facilitating economic development of Victoria.

Pricing options, and demand management issues, were examined in a separate electricity pricing review process which was initiated subsequent to the commencement of the joint SECV/DITR study (SECV/DITR 1990).

The load management programs of most electricity utilities have usually included time-of-use pricing in one form or another. The Queensland Government stated that:

> Time of use prices are available in Queensland to all sectors of customers. Domestic time of use tariffs are limited to controlled off-peak and overnight "water heating" tariffs although other permanently connected appliances may be supplied under these tariffs.

There are differences in how reflective the prices of the differing utilities are of the underlying costs and whether they are restricted to certain consumers or for certain end uses. Most commonly, time-of-use pricing applies to large electricity users and for the provision of domestic hot water.

Some governments and utilities argue that the extension of time-of-use pricing to the domestic sector is limited by the costs associated with new metering devices. The Western Australian Government stated that, due to these metering costs, the broadening of time-of-use tariffs would need to be phased in over an extended period of time. The New South Wales Government argued that priorities need to be established in broadening the availability of time-of-use pricing. For instance, 50 per cent of electricity sales could be placed on time-of-use pricing with the installation of meters to approximately 1 per cent of customers.

The option for residential time-of-use pricing has recently become available in Victoria through the SECV's Weekend Incentive and Night Economy Rate (the so called 'winner tariff'). Users paying metering conversion costs can choose between the present domestic and off-peak water tariffs and the winner tariff.

Interruptibility clauses

Interruptible supply arrangements are used to save capacity expansion that would normally be required to cover peak or unexpected increases in demand or system breakdowns. Part of the savings are passed onto the consumer in the form of rebates or lower prices.

The Queensland Government stated that interruptible supply arrangements are most effective with larger customers because the costs of control equipment and coordination make such arrangements with smaller customers less practicable. In the Northern Territory, interruptibility clauses are being examined in terms of deferring generation augmentation.

The ECNSW uses Load Reduction Agreements with major electricity users. For example, ICI Australia stated that the chlorine cells at its Botany site, which uses electricity equivalent to that of 80 000 domestic customers, could be shed without notice.

In South Australia, Sagasco has negotiated interruptibility clauses in the supply contracts for three large volume customers. These contracts enable Sagasco to reduce the hourly gas consumption of these customers on peak days. In this way, Sagasco avoids paying PASA penalties for exceeding their contracted maximum daily quantity.

To manage peak demand, the GFCV also uses interruptibility clauses in contracts for major industrial customers. However, BHP Petroleum (BHPP) stated that inefficiencies occur because of its current sales contract with the GFCV. BHPP argued that total investment could be minimised if gas producers and large end use consumers were able to negotiate directly. In turn, this would enable tradeoffs to be made between investments to increase production capacity and investments to decrease peak loads.

Energy efficiency advisory services

Most utilities offer advisory services to promote the efficient use of energy. In some cases the provision of these services fulfils the statutory obligations of the organisation. In others, they are viewed as a community service activity because they recommend 'measures which reduce electricity use or encourage use of other energy sources'.

The range of advisory services offered by the various energy utilities differ:

- in New South Wales, the electricity supply industry provides free advice to customers on energy efficiency and promotes/sells energy efficient products;

- the SECV conducts an extensive range of advisory services including the distribution of literature on the efficient use of electricity, liaison with building industry associations on the installation of efficient electrical equipment, a do-it-yourself domestic audit scheme and fee-for-service commercial and industrial audits;

- SECWA offers free advice on the efficient use of energy and on the selection of energy appliances. It has also promoted the use of natural gas to slow demand growth during the winter peak period;

- HECT provides advice on energy use to domestic customers and to commercial and industrial users on a fee-for-service basis;

- GFCV operates a program to improve efficient use of gas, including the promotion of high efficiency gas appliances; and

- the City of Brunswick Electricity Supply Department provides marketing and advisory services to customers on the relative efficiency of electric and gas appliances.

Energy labeling and standards

In 1987, the Victorian and New South Wales Governments initiated an energy labeling program for major residential electrical appliances such as refrigerators, freezers, air conditioners, dishwashers, clothes washers and dryers. The program will be expanded to include cook tops and ovens during 1990-91. Electricity appliance labeling requirements have also been implemented in Western Australia and South Australia and will be implemented in Queensland. Labeling initiatives for gas appliances have also been implemented by the GFCV.

In Victoria, appliance energy labeling will be extended to include all major electrical appliances used in the home. To complement this program, minimum efficiency standards are to be developed for residential appliances; in particular, the large energy consuming appliances such as water and space heaters, refrigeration, microwaves and clothes dryers.

Energy standards are also to be developed for new residential and commercial constructions in Victoria. The residential standards are expected to specify minimum performance requirements for the thermal integrity of the envelope of new buildings. A new house energy rating scheme is also to be introduced replacing the current 5 Star Design Rating Scheme. The new scheme is expected to apply to all new residential constructions and will also be available for existing houses. The commercial standards will also concentrate on the building envelope, as well as improvements to lighting and heating, ventilation, and air conditioning systems (SECV/DITR 1989c).

Research and development

Research and development on energy conservation is coordinated and supported through the Commonwealth's National Energy Research, Development and Demonstration (NERD&D) Program. The Program is primarily focussed on information, demonstration and technology transfer. This emphasis is in line with the Commonwealth's objectives of facilitating the efficient use of energy by complementing the market signals provided by energy prices while minimising the use of regulation and financial incentives.

During 1988-89 the Commonwealth provided $2.1 million to 14 projects aimed at improving the efficiency of energy use in primary and secondary industries and in buildings. Grant funds are usually matched by other funds from the states and industry. Commonwealth funding represented only 24 per cent of the total funding required by the projects supported under the Program.

The ECNSW is focussing its research and development efforts into energy efficiency; the area, it considers, offers the greatest long term benefits.

Evaluative criteria

The ESAA argued that, as a tool for balancing future supply and demand, it is unclear what level of DSM is economically viable and that evaluation of current initiatives is needed prior to further commitments.

As with the DSM programs themselves, the development of criteria to evaluate the potential and on-going performance of particular activities remains in the formative stages. This is despite the fact that many activities, in particular load management initiatives, have been common in the past.

A number of energy utilities have developed criteria to judge, and undertaken studies to assess, the effectiveness of some DSM activities. The primary objective of the Victorian demand management development project was for the SECV and DITR to develop a method to prioritise programs for balancing supply and demand into the future. This was achieved through the 'least cost' approach, scenarios which acknowledged the uncertainty of the future and the use of multiple decision criteria.

The SECV/DITR (1989b) study argued that the principle criterion should be one based on total resource usage; though other criteria would be required since DSM activities provide broader benefits to society as well as to participants and should allow the SECV to operate in a business-like manner. The criteria developed included:

- societal measures - total resource usage, public service sector energy service costs, environmental emissions impact and SECV plus customers' debt;
- DSM program measures - all SECV customers' impact and program participants' benefits to costs ratios; and
- SECV business measures - SECV capital risk, borrowings to capital and debt.

The study recognised that an implementation strategy needed to be developed and that DSM options needed to be critically assessed in terms of their effectiveness and impact on the Victorian market. The study also acknowledged, that the evaluative criteria should not be used to analyze issues with a level of precision inappropriate for the reliability of the input information.

To assess the effectiveness of some DSM activities, and to maintain existing activities, it was decided to initiate a three year demand management action plan. The plan consists of a number of separate activities (eg appliance and building labeling and standards, energy audits and residential lighting replacement) and will allow measurement of the societal costs.

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