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INDUSTRY COMMISSION

17 May 1991

The Honourable P J Keating MP
Treasurer
Parliament House
CANBERRA ACT 2600

Dear Treasurer

In accordance with Section 7 of the *Industry Commission Act 1989*, we submit to you the report on Energy Generation and Distribution.

Yours sincerely

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Acting Chairperson

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Acknowledgement

The Commission wishes to thank those staff members who contributed to this report.

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MAJOR ABBREVIATIONS USED IN THIS REPORT

Energy Utilities

ACTEW	ACT Electricity and Water
AGL	AGL Gas Companies
ECNSW	Electricity Commission of New South Wales
ETSA	Electricity Trust of South Australia
GFCV	Gas and Fuel Corporation of Victoria
HECT	Hydro-Electric Commission of Tasmania
PASA	Pipeline Authority of South Australia
PAWA	Power and Water Authority, Northern Territory
QEC	Queensland Electricity Commission
Sagasco	South Australian Gas Company
SECV	State Electricity Commission of Victoria
SECWA	State Energy Commission of Western Australia
SMHEA	Snowy Mountains Hydro-Electric Authority
TPA	The Pipeline Authority

Government Departments/Agencies

ABARE	Australian Bureau of Agricultural and Resource Economics
ABS	Australian Bureau of Statistics
ALC	Australian Loan Council
CGC	Commonwealth Grants Commission
DITR	Department of Industry, Technology and Resources, Victoria
DPIE	Department of Primary Industries and Energy
IAC	Industries Assistance Commission
IC	Industry Commission
PSA	Price Surveillance Authority
TPC	Trade Practices Commission

Other

AGA	Australian Gas Association
CSO	Community Service Obligation
DSM	Demand Side Management
ESAA	Electricity Supply Association of Australia
ESI	Electricity Supply Industry
IES	Intelligent Energy Systems Pty Limited
LNG	Liquid Natural Gas
LPG	Liquid Petroleum Gas
MW	Megawatt
NGI	Natural Gas Industry
RPM	Reserve Plant Margin
TPA	Trade Practices Act

GLOSSARY

Availability Measure of the capability of generating plant for energy production during a period compared to the total energy production if the plant had operated continuously at full output during the period.

Base Load That part of the power demand which is effectively constant throughout the year. A unit providing this load should run on a continuous basis at a near rated capacity when not out of service for routine or annual maintenance. Such plant would normally operate with an annual capacity factor in excess of 60 per cent.

Capacity Factor Measure of the energy production of a generating plant during a period compared to the total energy production if the plant had operated continuously at full output during the period.

City-gate The point where gas emerges from the major supply pipeline for distribution to users.

Cogeneration The generation of electricity as part of some other process such as the supply of low pressure steam to a chemical plant or the recovery of waste heat and gases from a blast furnace.

Combined Cycle A two stage electrical generation process. In the first stage, electricity is generated by a gas turbine. The waste heat from this process then passes through a heat recovery boiler which produces steam for additional power generation in a conventional steam turbine. This results in an increase in overall power generation efficiency.

Common Carriage A requirement imposed on transmission or distribution system owners to carry third party electricity or gas.

Conservation The efficient use of energy, by forsaking energy needs or by using more efficient systems or appliances.

Demand Side Management Commonly defined as the systematic planning and implementation of energy utility services designed to influence customer use of energy in ways that will produce desired changes in the utility's load. It is also known as demand management and encompasses both load management and energy conservation.

Energy A measure of the amount of electricity or gas used over a period of time. Units commonly used for electricity are gigawatt-hours

(GWh), megawatt-hours (MWh) or kilowatt-hours (kWh), depending on the power and time scale involved. As with electricity, the unit used to measure gas consumption varies with conditions of use. Common units include megajoules (MJ) and gigajoules (GJ).

1 kWh = 3.6 MJ

1 GJ = 277.8 kWh

Forced Outage The unscheduled outage of a generating unit due to the occurrence of a component failure or other condition which requires the unit to be taken out of service for repairs or inspection.

Gas Turbine A generating unit in which an air/fuel mixture is burnt, with the resulting hot air/gas mixture used to drive a turbine. The turbine drives a generator to produce electrical energy.

Hydro-electric Generation A term for the generation of electrical energy by turbine alternators driven by a flow of water.

Intermediate Load That part of the power demand which falls between the highly fluctuating peak loads and the steady base load components. Plant supplying intermediate loads typically operate during weekdays and are shut down or off-loaded overnight and during weekends. This plant would generally operate at an annual capacity factor of between 30 and 60 per cent.

Liquefied Natural Gas (LNG) Natural gas compressed and cooled to liquid form.

Load Factor The ratio of the average load (in MW) supplied, over a period, to the peak or maximum load during that period. Usually expressed as a percentage.

Loss of Load Probability A statistical parameter which measures the average time during the year in which the power supply system will be unable to fully meet demand.

Merit Order Ranking of plant in economic order (increasing generation cost) of operating on the system.

Off-peak A time span of lower electricity usage which would normally include public holidays, weekends and 10 pm to 7 am on weekdays.

Open Access Similar to common carriage, but with access subject to the availability of capacity.

Peak Load That part of power demand which occurs for relatively short periods, mainly during week-day mornings and evenings. Plant specifically installed to meet this part of the load might operate on annual capacity factors of up to 30 per cent. However, this depends on the mix of generating plant available in the system.

Power A measure of the instantaneous demand for electricity. Units used are gigawatts (GW), megawatts (MW) or kilowatts (kW), depending on the scale involved.

Pumped Storage The use of surplus generating capacity to pump water into storage from which it can be later drawn down to generate electricity by passing through a turbo alternator.

Reliability The ability of the system to meet the demand imposed by users.

Renewable Energy Energy obtained from sources which are naturally regenerated. This encompasses hydro, solar, wind, tidal, wave and geothermal sources.

Reserve Plant Margin The total plant capacity available less the actual maximum demand for electricity in a particular year, expressed as a percentage of the maximum demand.

Scheduled Outage The planned removal of a generating unit from service for routine or preventative maintenance.

Spinning Reserve The reserve on the system to provide for unexpected loss of generation.

Standby The use of generating plant to cover unexpected outages of other plant or sudden increases in load.

Town Gas A gas manufactured from coal or NAPTHA, prior to the introduction of reticulated natural gas. Now largely replaced by tempered natural gas or LPG.

PART I

BACKGROUND INFORMATION

TERMS OF REFERENCE

I, PAUL JOHN KEATING, in pursuance of Section 7 of the Industry Commission Act 1989 hereby:

1 refer the generation, transmission and distribution of electricity and the transmission and distribution of gas, excluding tax, resource rent and royalty issues relating to gas, for inquiry and report within twelve months of the date of receipt of this reference;

2 specify that the Industry Commission report on institutional, regulatory or other arrangements subject to influence by governments in Australia which lead to inefficient resource use, and advise on courses of action to reduce or remove such inefficiencies;

3 without limiting the scope of the reference, request that the Commission give priority to areas where greatest efficiency gains are in prospect, and areas where early action is practicable, having regard to:

(a) the scope for improving the efficiency of electricity generation, transmission and distribution and gas transmission and distribution including through changed management and work practices, the removal of structural impediments and the use of, and investment in, new technology,

(b) the scope for rationalisation of electricity and gas supply between the various authorities, for example by interconnections between systems;

(c) whether generation, transmission and distribution activities should be subject to control by the one organisation within the region;

(d) whether electricity and gas retailing is most appropriately performed by a central authority or by a number of distributors;

(e) practical issues which may apply to the introduction of more efficient pricing policies;

(f) alternative efficient sources for infrastructure and other capital investments including any efficiencies arising from mechanisms for raising loan/or equity funding;

(g) the potential for additions to generating capacity, including from privately owned sources;

(h) the appropriateness of various load management and energy conservation initiatives to enhance efficiency of supply and use of energy; and

(i) the relative efficiency and cast effectiveness of options to reduce the environmental impact of burning fossil fuels*.

4 specify that the Commission is to have regard to the established economic, social and environmental objectives of governments; and

5 specify that the Commission is to avoid duplication of recent substantive studies undertaken elsewhere.

P. J. KEATING

20 MAY 1990

* In a letter from the Treasurer, dated 5 December 1990, the Commission was advised that this clause had been deleted from the terms of reference

1 INTRODUCTION

The efficiency of the electricity and gas supply industries affects the competitiveness of key Australian industries, including a number which sell in international markets. In recent years, there has been criticism of the performance of the electricity and gas supply industries. Some measures to improve efficiency have been introduced, but significant scope for further reform is acknowledged by both Governments and participants in the industries. It is imperative that their potential is fully realised.

The major function of this inquiry is to identify policies that will promote efficiency and ensure that the electricity and gas supply industries in Australia perform to their full potential. The inquiry, which is part of the Commonwealth Government's on-going program of micro-economic reform, follows a previous Industries Assistance Commission inquiry into Government (Non-Tax) Charges (IAC 1989). That inquiry proposed reviews of a number of areas of the economy, including electricity and gas, to help identify opportunities for improving efficiency.

1.1 The reference

The terms of reference for the inquiry, which were prepared in consultation with state and territory governments, are on the facing page. In December 1990, just prior to the forwarding of a new reference to the Commission on greenhouse gases emissions, the reference was amended to delete clause 3(i) concerning options to reduce the environmental impact of burning fossil fuels (see Appendix 1).

The terms of reference require the Commission to inquire and report on major issues associated with the electricity and gas supply industries. This involves consideration of the activities of Commonwealth, State and Local governments.

The reference asks the Commission to examine the scope for improving the efficiency of electricity and gas supply and to report on institutional, regulatory or other arrangements subject to influence by governments which lead to inefficient resource use. In addressing these matters, the Commission is to have regard to a range of specific issues, a number of which relate to alternative organisational arrangements. The Commission is also required to have regard to the established economic, social and environmental objectives of governments.

Activities covered by the reference are generation, transmission and distribution of electricity and transmission and distribution of gas. The Commission has interpreted the reference to include all forms of gas (eg liquid natural gas (LNG), liquid petroleum gas (LPG) and natural gas) and electricity generated for private use, as well as that generated for public sale. To the extent that other sources of energy, such as petroleum products, coal, uranium and renewable forms of energy compete with electricity and gas and/or are important inputs to electricity generation, they are also covered by the reference. Tax, resource rent and royalty issues relating to gas are explicitly excluded from the reference, as is the production of gas. Some participants (eg AGL Gas Companies (AGL)) stated that gas transmission and distribution issues could not be addressed adequately without consideration of gas production. The Commission has not examined gas production in detail. It has, however, recognised the linkages that exist between production and other sectors of the gas industry when developing proposals concerning transmission and distribution.

1.2 The Commission's approach

The economic performance of the electricity and gas supply industries is central to the well being of our community. They are major employers of the nation's resources. In addition, they supply vital inputs to virtually all Australian industry. Consequently, even modest improvements in their efficiency can have wide-ranging effects on competitiveness and economic development.

Concern has been expressed that the electricity and gas industries have not been functioning efficiently. It has been asserted that there is little incentive for efficiency. Virtually all of the electricity supply industry and significant parts of the gas industry are publicly owned and immune from commercial disciplines such as insolvency and the threat of takeover. Competition within each industry is negligible. Unlike many other domestic industries, there is no direct competition from overseas suppliers. To a large degree, the cost of any inefficiencies is borne by users and by taxpayers generally rather than by the electricity or gas industries.

In recent years, some useful measures to improve efficiency have been implemented by governments. However, the nature and extent of the reforms vary markedly. In some states, little progress has been made. The changes will do little to increase competition. Yet, without greater competition, improvements in efficiency may not be sustained.

Most participants in this inquiry acknowledged that there is a need for further reform. But there are differing views on what policies should be adopted. To date, the emphasis has been on administrative change introduced by government. This seeks to increase the incentive for efficient management of electricity and gas utilities without changing ownership or industry structures. Administrative change to public utilities, which is frequently characterised as `commercialisation' or 'corporatisation', seeks to place public utilities on a more commercial footing. In the case of private utilities - almost all of which are involved in gas supply - administrative change implemented by government has focused on introducing less intrusive and more market-oriented regulation.

Some major players - such as the Electricity Commission of New South Wales (ECNSW), the State Electricity Commission of Victoria (SECV) and the Queensland Electricity Commission (QEC) - have already demonstrated that administrative changes can improve performance. But they also agree that more substantial change is required if all of the potential efficiency gains are to be realised.

In view of these developments and the issues identified in the terms of reference, the major focus of this report is not so much on the present state of the industries, but on alternative ways to improve the economic performance of Australian electricity and gas utilities. Particular attention is given to the future structure and ownership of the industries, and the role that competition can play in improving performance.

The reference raises an extremely disparate and complex range of issues. In the time available to the Commission, it has not been possible to address comprehensively all of these issues or to comment in detail on their application to individual electricity and gas utilities. Indeed, given the technical expertise required to examine some questions (eg legal and engineering aspects of electricity pooling arrangements), consideration of the detail of some of the matters addressed by the Commission would be better undertaken by a specialist, but independent, body established for that purpose (see Chapter 7). Consequently, in developing its proposals, the Commission has outlined a set of principles and an associated policy framework which, if applied by governments, would improve efficiency. In doing so, the Commission has concentrated on areas where it considers the potential efficiency gains are largest.

As required by the reference, the report aims to build on, not duplicate, the ground covered by other studies. It is intended to assist future policy formation by governments. It may also assist Working Groups established by the Special Premiers' Conference to consider reform of government trading enterprises and possible extensions to the interstate electricity transmission network.

In keeping with the Commission's policy guidelines, options for change have been developed having regard to their implications for the economy as a whole rather than simply from the perspective of the electricity and gas industries. The policy guidelines require the Commission to have regard to the desire of the Commonwealth Government to: encourage the development of efficient industries; facilitate structural adjustment; reduce unnecessary industry regulation; and recognise the interests of other industries and consumers generally. The Commission is also required to report on the social and environmental consequences of any recommendations it makes.

1.3 Inquiry procedures

In preparing this report, the Commission has drawn on: written submissions; information tendered at public hearings; discussions with government departments responsible for energy policy, public and private energy utilities, users and other interested parties; and various published discussion and research papers. In addition, the Commission contracted Intelligent Energy Systems Pty Ltd to prepare a paper on the opportunities for introducing more efficient pricing policies.

A list of participants and other information concerning the conduct of the inquiry are set out in Appendix 1.

1.4 Structure of the report

The report is in three volumes. Volume 1 contains a summary and the Commission's recommendations. Volume 2 contains the report proper. It presents details of the Commission's analysis and its evaluation of various policy options. Supporting appendixes are in Volume 3.

2 KEY FEATURES OF THE ELECTRICITY AND GAS SUPPLY INDUSTRIES

The electricity and gas supply industries are large and important suppliers to Australian industry and to households. Government involvement in both is extensive. All major electricity utilities and most major gas utilities are publicly owned Both private and public electricity and gas utilities are subject to substantial Commonwealth, State and Local government regulations. The stricture of both industries varies significantly between states/territories.

This chapter provides a brief overview of the main characteristics of the electricity supply industry (ESI) and the gas supply industry, their markets, the linkages between the industries and the remainder of the economy, and the regulatory environment in which they operate.[1] An understanding of these matters is an important prerequisite for evaluating approaches to improving efficiency.

2.1 Industry size

The electricity and gas supply industries are both significant Australian industries. In 1986-87, the latest year for which comparable data are available, value added[2] and employment by the two industries were, in aggregate, $6.9 billion and 90 000 persons respectively. This corresponded to about 2.6 per cent of gross domestic product and 1.3 per cent of total employment[3]

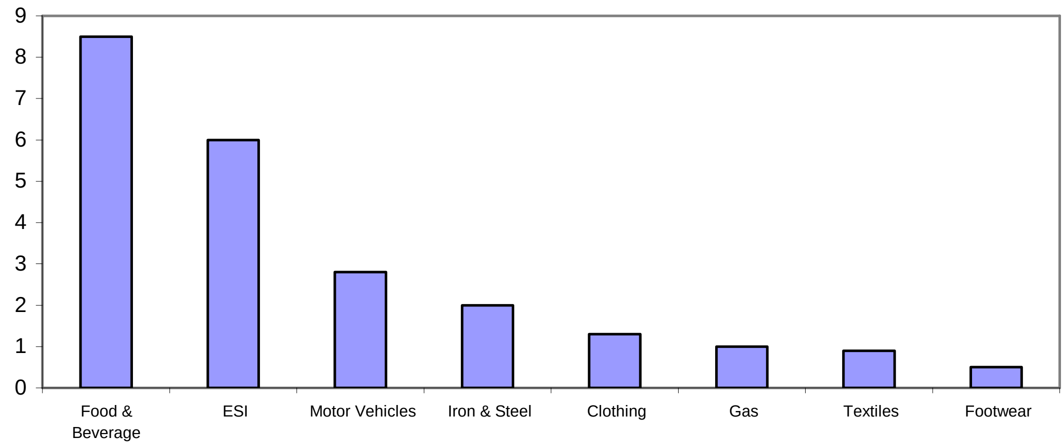
The ESI is by far the larger of the two industries, accounting for around 85 per cent of aggregate value added and employment in 1986-87. It is one of Australia's biggest industries. In terms of value added in 1986-87, it was smaller than the food and beverage industry, but over double the size of the Australian motor vehicle industry and nearly three times the size of the iron and steel industry. Value added in the same year by the gas supply industry exceeded that of both the footwear and the textile fibre and fabric industries, and was about 15 per cent less than that achieved by the clothing industry. Figure 2.1 illustrates the relative size of the industries.

1 These matters are discussed in detail in Appendix 2 (Industry Structure and Markets) and Appendix 3 (Current Legislative and Regulatory Framework).

2 Value added broadly corresponds to the net value of production (ie the value of output less the value of material inputs used to produce that output).

3 Mainly because of a significant decline in employment in the ESI in several states, employment in the two industries is estimated to have decreased by around 15 000 since 1986-87.

Figure 2.1: **Value added of selected major industries, 1986-87**



Sources: ABS (1988,1989a)

2.2 Ownership and structure

There are many similarities between the electricity and gas supply industries. For example, both industries:

- require large and lumpy capital investments which, once commissioned, have little alternative use;
- involve extensive transmission and distribution networks which result in parts of the industries exhibiting natural monopoly characteristics;[4]
- consist of enterprises which produce virtually identical outputs; and
- have many major domestic markets in common.

Despite these common features, there are quite striking variations in the ownership and structure of the two industries.

[4] A natural monopoly arises where the entire output of a market can be supplied at a lower cost by one supplier than by any combination of two or more firms. This outcome reflects the presence of economies of scale and/or scope.

Ownership

In the early 1900s, the ESI consisted of a mixture of private and public enterprises. However, over the ensuing 20 or 30 years public sector ownership increased. By the late 1940s, the industry was predominantly government owned. This trend towards public ownership has been attributed to a combination of factors including: the significance of scale economies; the inability of the private sector to finance the large new investments required; government concerns about the exploitation of market power and national security; and government decisions to use electricity pricing as a means of pursuing social and development objectives (see Boehm 1956). While these factors no longer require that the industry be publicly owned (see Chapter 8), the overwhelming bulk of the ESI remains in public hands.

About 93 per cent of electricity used in Australia is provided by public utilities. Of the remainder, most is generated by private firms for their own use and for public supply in some remote areas (eg in Western Australia).

Electricity infrastructure is mainly owned by state or local governments. The assets of the Snowy Mountains Hydro-Electric Authority (SMHEA) are owned by the Commonwealth Government.

Some parts of the industry concerned with the supply of electricity for public sale are privately owned. For example, the Darwin to Katherine transmission line is maintained and operated by a private company. The Eraring power station in New South Wales is owned by private interests, but is maintained and operated by ECNSW personnel. In both instances, the arrangements were prompted by taxation and financing advantages rather than any perceived benefits associated with private ownership. However, over the last year or so, most electricity authorities have, to a limited extent, encouraged increased private sector participation as a means of increasing efficiency. This has included calling for expressions of interest for the construction of new power stations and initiatives intended to promote private sector generation for sale into state electricity grids. For example, the SECV has sold its transport interests and presently wishes to sell the partly completed Loy Yang B power station. The New South Wales Government has sought expressions of interest from parties interested in purchasing ECNSW coal mines. In 1991, the Western Australian Government announced that private enterprise would build, own and operate the State's next major power station.

Private ownership of gas infrastructure is more prevalent. In Queensland, for example, the pipeline from Roma to Brisbane and the two natural gas reticulation networks servicing the city are owned by private firms. Private firms are also responsible for distribution of other forms of gas (eg LPG and LNG) in all states and territories. Distribution of natural gas in New South Wales and the ACT is also undertaken by private enterprise. The Pipeline Authority (TPA), which owns and operates the gas pipeline from Moomba to the outskirts of Sydney and associated spur lines, is a Commonwealth Government authority. In some states, mixed public-private utilities exist. For example, about 28 and 21 per cent respectively of the issued shares of the Gas and Fuel Corporation of Victoria (GFCV) and the holding company of the South Australian Gas Company (Sagasco), SAGASCO Holdings, are privately owned, with the remainder being government owned.

Industry structure

Industry structure is an important factor influencing performance. However, in both industries, there are substantial differences in structure across Australia.

Both the electricity and gas supply industries consist of large enterprises which face little or no direct competition from alternative suppliers. (Though there is some competition between the electricity and gas industries.) One minor exception is the supply of gases other than natural gas (eg in many regions there are competing distributors of LPG).

A major difference between the ESI and the natural gas industry (NGI) is the extent of vertical integration. In the Northern Territory and four states - Victoria, South Australia, Western Australia and Tasmania - a central authority has control over the three major facets of electricity supply: generation, transmission and distribution.[5] Additionally, in two of these states - Victoria and South Australia - a substantial proportion of the industry's fuel requirements is met from state owned coal deposits. In New South Wales, the responsibility for distribution is separated from transmission and generation. Although subject to some control by the QEC, distribution is also nominally separated from generation and transmission in Queensland. One authority, ACT Electricity and Water (AC FEW) oversees the distribution of electricity in the ACT - all of which is purchased from ECNSW and the SMHEA. ACIEW is also responsible for water and sewerage services. In the Northern Territory, responsibility for both electricity and water and sewerage is also vested in the one body - the Power and Water Authority (PAWA).

Vertical integration is less pronounced in the supply of natural gas although, as in the case of electricity supply, the arrangements vary between regions. Unlike electricity, no state/territory has its gas supply controlled by the one vertically integrated enterprise. In Victoria and Western Australia, the one authority is responsible for transmission and distribution, but neither has formal links with the gas producers. In the other states, transmission and distribution of gas are performed by separate bodies. In some cases (eg New South Wales and Queensland), there are ownership links between the distribution body and the gas producers. Gas exploration and production is predominantly undertaken by private enterprise.

5 Exceptions include 11 municipal councils in Victoria which distribute electricity to parts of the Melbourne urban area, the transmission of electricity from Darwin to Katherine and the responsibility for supply to some remote communities in the Northern Territory, South and Western Australia.

A feature unique to Western Australia is that the one authority - the State Energy Commission of Western Australia (SECWA) - has primary responsibility for generation, transmission and distribution of electricity, and also for the transmission and distribution of natural gas.

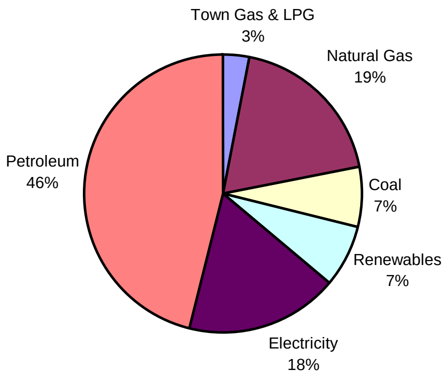
2.3 Linkages with other sectors of the economy

Energy markets

Gas and electricity are major forms of energy. Gas is a natural, or primary, source of energy. In contrast, electricity is a derived form of energy obtained from the conversion of a number of primary energy sources (eg coal and gas). Unlike gas, there is no capacity to store electricity. It must be produced instantaneously upon demand.

Collectively, electricity and gas supplied around 40 per cent of final Australian domestic energy availability in 1989-90.[6] Of this, electricity accounted for about 18 per cent and gas - predominantly natural gas - represented a further 22 per cent. The contribution of each major energy source in 1989-90 is shown in Figure 2.2.

Figure 2.2: **Final Australian domestic energy availability, 1989-90**



Source: ABARE (1991)

[6] Final Australian domestic energy availability is the amount of energy available for domestic consumption, taking into account imports and exports, after allowing for net losses resulting from energy conversion processes (eg coal used for generating electricity).

The major domestic markets for electricity in 1989-90 were the manufacturing sector (41 per cent of total sales), the residential sector (29 per cent) and commercial users (20 per cent) (see Figure 2.3).

The latest available information on usage by individual industries is input-output data for 1986-87. These show that, in absolute terms, the largest users are those industries associated with: Business services; Public administration; Non-ferrous metals (including aluminium); and Health. The significance of electricity relative to other inputs is highest for Non-ferrous metals; Cement; Pulp and paper; Restaurants, hotels and clubs; and Public administration. Purchases by each of these industries accounted for around 5 per cent of the total cost of their intermediate inputs.

The input-output data relate to broad industry classes. Consequently, they do not reveal the significance of electricity to some industries. For example, CRA stated:

> Electricity is a basic input into aluminium production, representing about 30% of the operating cost of an average aluminium smelter. As such the cost of electricity and reliability of supply and charges is fundamental to the international competitiveness of an aluminium smelter.

ICI stated that electricity constitutes a significant proportion of key products produced at its Botany plant. The company said that electricity represents 64 per cent of the variable costs of its production of both caustic soda and chlorine.

The manufacturing sector is by far the major domestic user of natural gas, accounting for about 43 per cent of the volume of domestic sales in 1989-90. This figure includes gas used as a feedstock for some industrial processes (eg the manufacture of fertiliser). Other major users were the ESI (23 per cent) and households (12 per cent) (see Figure 2.4). In addition, increasing quantities of LNG are being supplied to Japan.

Input-output data show that, in 1986-87, the major users of natural gas were the industries categorised as: Electricity; Non-ferrous metals; and Clay products. Compared with purchases of other inputs, natural gas purchases were most significant for the Clay products (6 per cent of the value of all inputs purchased from other industries), Glass and glass products (4 per cent) and Cement industries (3 per cent). However, these data cloud the significance of natural gas to some producers. The figures also do not reflect the significant increase in the use of natural gas over recent years. For example, one major user - Incitec - submitted data showing that natural gas accounts for 57 and 42 per cent of the production cost of ammonia and urea respectively. The company uses natural gas as an energy source and also as a feedstock.

Manufacturing industry and the residential sector are the major areas in which electricity and gas compete. Electricity competes with gas, or has the potential to compete, in virtually all applications in which gas is employed as an energy source. In contrast, there are many areas in which gas cannot compete directly with electricity. Gas cannot readily provide motive power or be used for lighting, information systems, air conditioning, certain industrial processes and a wide range of household appliances.

A feature common to the ESI and NGI is the very low proportion of interstate sales. Significant domestic trade in natural gas is, with one exception (sales from the Moomba gas fields in South Australia to New South Wales and the ACT), currently confined to intrastate trade .[7] As discussed in Chapter 6, this largely reflects limits on the 'export' of gas from some states and other requirements imposed by state governments (eg the removal of condensate prior to 'export'). Interstate trade in electricity only occurs between New South Wales, Victoria and, more recently, South Australia.[8] Compared to the total quantity of electricity generated in these states, these sales are minor, representing less than 2 per cent of electricity produced in the three states. This is small compared with other countries. For example, in Europe the equivalent figure for trade between nations, let alone trade between regions within countries is, for a number of countries, 10 per cent or higher. A number of reasons contribute to this outcome (see Appendix 6).

Figure 2.3: **Major electricity markets, 1989-90**

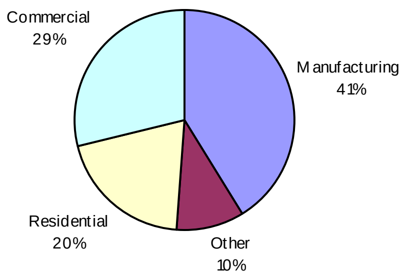
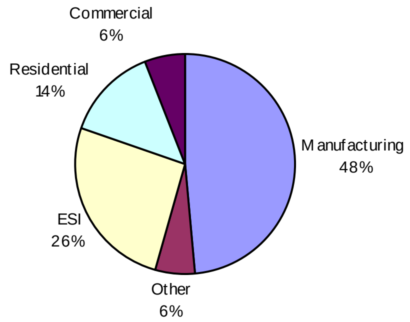


Figure 2.4: **Major natural gas markets, 1989-90**



Source: ABARE (1991) Input markets

Input markets

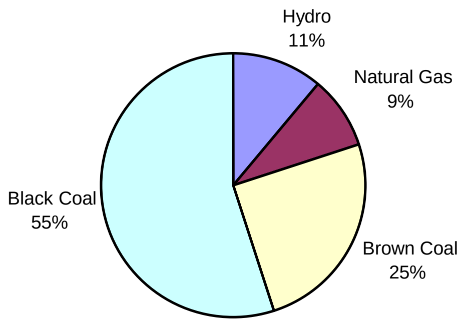
The major primary fuel sources for the ESI in 1988-89 were black coal (about 55 per cent, in energy terms, of total fuel inputs), brown coal (25 per cent), hydro (11 per cent) and gas (9 per cent) (see Figure 2.5). No electricity is produced from nuclear power in Australia.

7 The New South Wales city of Albury is supplied by the GFCV, but accounts for only a small proportion of the GFCVs sales.

8 In addition, the Tweed Shire of New South Wales near the Queensland border is supplied from the Queensland grid and some areas in south-west Queensland are connected to the New South Wales electricity grid.

The use of gas for electricity generation has increased in recent years. This trend is expected to continue. Recently, the Victorian Government announced that it will probably defer plans for the construction of units three and four of the coal-fired Loy Yang B power station and will instead build a gas-fired plant. The ESI itself is also a major user of electricity.

Figure 2.5: **Major primary fuel sources for the ESI, 1988-89**



Source: ESAA (1990)

2.4 Regulatory framework

Both industries are subject to a wide array of government regulations. Most regulations are at the state/territory level, but there is also some Commonwealth Government involvement and, to a lesser extent, local government regulation. The regulatory framework, which is discussed in Chapter 5 and Appendix 3, covers three main areas: entry restrictions; controls over the operations of electricity and gas utilities; and environmental and safety standards.

Entry restrictions

Regulations governing entry apply to both electricity and natural gas supply. They either prohibit new entrants or allow entry only with government approval. These measures have insulated electricity and gas utilities from competition from alternative suppliers.

Electricity can only be generated for public sale with the approval of the relevant electricity authority and/or Minister.

The major restrictions on entry to the transmission and distribution of natural gas are franchises, licences and other authorisations issued to incumbent enterprises. In most states/territories, these provide a distributor with the exclusive right to supply a defined area. In some states, licences have been issued on an indefinite basis while, in others, they are for a defined period. Entry to the NGI has also been restricted by state government policies which have prohibited or restricted the ‘export’ of natural gas to other states. Although a number of states/territories require that licences be obtained for the distribution of other forms of gas, entry restrictions are less stringent.

Operational controls

A wide range of government controls apply to public electricity utilities. While there has been some reduction in recent years, state controls over expenditure, borrowings and tariffs apply to most public authorities. In addition, controls over less significant matters such as staffing levels, contracts and purchases apply to some authorities. Commonwealth Government control is exercised mainly through a policy that restricts the importation of nuclear technology and through state borrowing limits which are determined by the Australian Loan Council.

Regulatory controls over the. operations of private natural gas utilities are mainly directed at overcoming the potential of utilities to exercise market power. The regulations vary markedly from state to state and are substantially different from those that apply to their public sector counterparts. For example, while public utility prices are generally monitored by requirements to seek government approval, private utilities' prices are subject to price capping mechanisms or to perusal by an independent review body. Some inconsistencies exist. For example, while the privately owned pipeline from Roma to Brisbane is required by state legislation to provide access to third parties, the publicly owned pipeline to Gladstone is not formally subject to this requirement. Other state government controls over private gas utilities include restrictions on shareholdings and requirements to pay license/authorisation fees (see Chapter 6). Private distributors of gases other than natural gas are exempt from most of these controls. Commonwealth Government control over gas is mainly exercised through export control powers.

Other Commonwealth Government powers which can apply to both electricity and gas include taxation and foreign ownership controls.

Environment and safety regulations

Electricity and gas utilities are required to comply with state/territory and, in some cases (eg major development proposals), Commonwealth Government environmental policies covering emission standards, planning controls, assessment procedures and the like (see Appendix 10). In some states/territories, there are associated demand management and/or energy conservation requirements.

Both private and public utilities are required to comply with safety provisions governing the production and distribution of electricity and gas.

3 THE ECONOMIC PERFORMANCE OF THE ELECTRICITY AND NATURAL GAS SUPPLY INDUSTRIES

This chapter illustrates the nature of the problems that have impaired efficiency in the electricity and natural gas supply industries in recent years. Some initiatives have been implemented to try to redress these problems. However, many of the problems persist. It is clear that there is significant scope for further improving efficiency.

This chapter briefly discusses the performance of the ESI and NGI over the last five or so years (Section 3.2), outlines initiatives to improve performance (Section 3.3) and comments on the scope for further improvements (Section 3.4). The chapter does not seek to assess the efficiency of individual utilities, or to assess comprehensively the current performance of the industries. The primary purpose is to illustrate the nature of problems - many of them ongoing - which have given rise to the changes made to the operations of electricity and natural gas utilities over recent years. As a preliminary to this discussion, the following section sketches out a basis for assessing performance.

3.1 Basis for assessing performance

Important indicators of performance which apply to private organisations are not applicable to public electricity and gas utilities. Government enterprises are not subject to the disciplines of the sharemarket. Takeovers and bankruptcy are non-existent. Indeed, with government support, inefficient enterprises can continue to exist indefinitely. Where there are no direct competitors, there is no meaningful market share data with which to analyse performance. Assessment of the financial performance of public utilities is complicated by: the divergent and, in some cases, unorthodox accounting practices adopted; requirements imposed on utilities by governments to discharge certain community service obligations (eg to provide energy at concessional rates to some users); and by the presence of other factors affecting financial performance (eg taxation exemptions) which do not apply to private sector organisations.

In the case of private utilities, the high level of government regulation and significant differences in the regulatory and operating environment in different states are key factors complicating assessment of their performance. In addition, separate information about the gas transmission and/or distribution activities of private companies owning gas utilities is limited.

Because of these factors, it is difficult to make a comprehensive assessment of the economic performance of the electricity and natural gas industries. Nevertheless, there is information available which provides some insights into performance. The Commission has drawn on this information to briefly outline some of the problems identified in the industries over the last five years or so with respect to the two major dimensions of economic efficiency –'productive efficiency' and 'allocative efficiency'.

- *productive efficiency* involves producing outputs in a manner which minimises costs, both at a point in time (static efficiency) and over the course of time (dynamic efficiency). If costs are not minimised, resources are wasted.

- *allocative efficiency* essentially relates to whether prices are consistent with the consumption by the community of a mix of goods and services that will maximise economic welfare. As discussed below, this generally requires that prices reflect the cost of efficient supply, including a return on capital.

Given the available information, there is little option but to rely on a range of partial indicators of productive efficiency. For example, evidence provided to this inquiry of surplus capacity and overstaffing suggest that large improvements in productive efficiency are feasible.

Assessing allocative efficiency is also difficult. Views vary on what constitutes the most efficient form of pricing and on the practicality of implementing efficient pricing practices. For example, while there is fairly widespread agreement that prices should reflect supply costs, there is disagreement about whether short-run or long-run costs should apply, and about how 'supply costs' should be defined. It is not possible to state unequivocally that one particular form of pricing will always be the most efficient. Prices should, however, be sufficient to recover the cost of efficient supply, including a rate of return on capital. For most activities, this outcome is achieved if prices reflect the marginal costs of production.

This approach will not be appropriate if average unit costs for a particular activity continue to decline as output increases. This characteristic is often ascribed to parts of the ESI and NGI - namely transmission and distribution. In these circumstances, prices which reflect marginal costs will result in revenue not being sufficient to recover all supply costs. Two alternative policies which would permit costs to be recovered, while minimising any adverse effects resulting from a departure from marginal cost pricing, are:

- *two-part tariffs* - these consist of a charge to cover fixed costs (often referred to as an 'access charge'), levied in conjunction with a usage (or energy) charge related to consumption, based on marginal costs.

- *Ramsey pricing* - this involves discriminating between consumers by charging different prices to different groups of users, depending on how sensitive their level of consumption is to price variations. This can permit prices to be set which will recover costs, while minimising changes to that pattern of consumption which would prevail if there were a competitive market. Under this approach, charges to users who are relatively responsive to price variations would closely reflect marginal cost, while users whose consumption is relatively unresponsive to variations in price would be charged higher prices.

In the absence of explicit statements about the basis for establishing prices and without supporting revenue and cost data, assessing the efficiency of utilities' pricing policies is difficult. Nonetheless, in some circumstances (eg if prices charged are not sufficient to cover marginal cost or if excessive profits are realised) it is clear that prices are not structured as efficiently as they could be. Evidence provided to the Commission clearly indicates that inefficient pricing practices do exist in both the electricity and the natural gas supply industries.

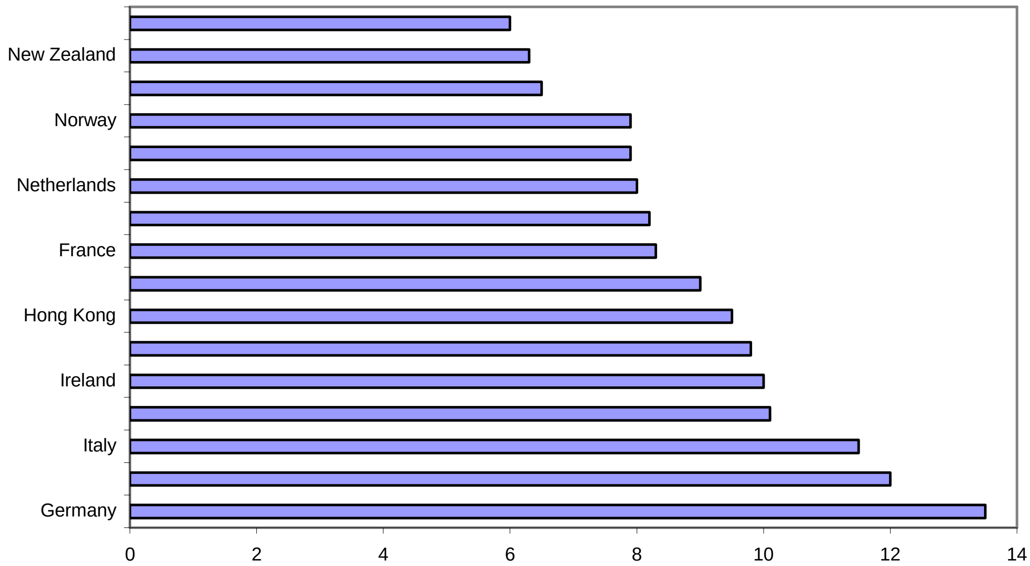
3.2 Recent performance

Reforms implemented and foreshadowed in the last few years - such as on-going reductions in staffing levels in a number of electricity authorities and major revisions to gas regulations in New South Wales and Queensland - suggest that the industries are undergoing significant change. Given these developments, this section primarily seeks to illustrate those aspects of performance which recent policies have sought to improve, rather than to assess comprehensively the performance of the industries at one point in the current transitionary phase. The Commission has drawn on participants' submissions and its own analysis, as well as work undertaken by the Industries Assistance Commission into the ESI as part of its report on Government (Non-Tax) Charges (IAC 1989) and other published reports.

Productive efficiency

International price comparisons are frequently cited as good indicators of productive efficiency. One set of data submitted to the inquiry shows, for example, that electricity prices in Australia generally compare favourably with those in other developed countries (see Figure 3.1). However, these data do not compare Australian prices with electricity prices in developing countries, some of which sell products which compete in international markets with Australian goods. For example, CRA stated that new aluminum smelters being constructed in Latin America and the Middle East will enjoy considerably lower prices than those available in Australia. The company attributed this to the availability of low cost fuel - hydro in Latin America and flare gas in the Middle East.

Figure 3.1: **Comparison of electricity prices in selected countries, April 1990**
Average price in cents/kwh



Note: 1. All prices quoted in Australian cents as at 2 April 1990.
2. Data are exclusive of government taxes/imposts.

Source: Submitted by ESAA and based on data compiled by N.U.S. International Pty Ltd.

More importantly, price comparisons, no matter how comprehensive, do not show whether our industries are performing to their full potential. Given Australia's gas resources and the ready availability of coal for electricity generation, electricity and gas prices in Australia should compare favourably with countries having poorer energy sources. The relevant question is: could electricity and gas be produced more efficiently so as to permit prices to be even lower than they are at present? Factors affecting efficiency need to be considered to answer this question.

Electricity

A study by Lawrence, Swan and Zeitsch (1991) examined the performance of the five mainland state electricity utilities between 1975-76 and 1989-90. The study found that average annual growth in total factor productivity (TFP)[1] in all authorities was less than 1 per cent between 1975-76 and 1982-83. With the exception of South Australia, all other state utilities have significantly improved their performance since then, achieving average annual increases in TFP of between 3 and 7 per cent. The TFP for South Australia declined between 1982-83 and 1989-90. In 1989-90, the highest levels of total factor productivity were achieved by Queensland and Western Australia. The results of the study and the methodology employed are discussed further in the following chapter.

1 Total factor productivity, the main measure of performance employed by the study, is an index of the ratio of total output quantity to total input quantity.

One factor which has reduced the productive efficiency of most electricity authorities over recent years has been excess generating capacity. Reserve capacity is required to meet unexpected outages and to permit plant closure for planned maintenance. However, a number of factors can frustrate attempts by electricity authorities to maintain optimum levels of capacity. For example, forecasting future demand is difficult, and new plant is ‘lumpy’ and adds significantly to total system capacity.

The reserve plant margin (RPM) is one measure of the utilisation of generating capacity.[2] In the mid-to-late 1980s, the RPM for major mainland authorities ranged from about 40 to over 70 per cent (see Table 3.1). This is high compared to the margins of 2025 per cent which are commonly regarded as satisfactory overseas (lEA 1985, pp. 64-65). Largely as a result of plant closures and increases in demand, RPMs have fallen in recent years. In the light of lower than forecast demand in most mainland states, some plant closures would have been accelerated to reduce net variable costs. However, the financial and other fixed costs associated with closing plants earlier than planned would remain as costs to consumers and/or taxpayers.

Table 3.1: **Reserve plant margin (RPM) by State, 1986-87 to 1989-90[a]** (per cent)

			State		
Year	*NSW* [b,c]	*Vic*[b,d]	*Qld*[e]	*SA*	*WA*
1986-87	73	50	47	62	46
1987-88	70	46	53	50	42
1988-89	69	38	47	38	24
1989-90	46[f]	27	37	45[g]	25

a Data for the HECT are excluded because measures of RPM for hydro systems are not comparable with RPMs for the predominantly thermal systems which exist in other states.
b SMHEA is included in New South Wales and Victoria in proportion to entitlements.
c Takes no account of the downrating of Liddell, Vales Point B and Wallerawang C plants over the period 1986-1989. The plants were returned to their original rating in 1990.
d Includes Anglesea.
e Includes dry stored plant at Swanbank.
f Excludes Tallawarra B and Vales Point A which have been decommissioned.
g Includes Osborne as that plant was not decommissioned until after the 1989-90 peak.

Sources: IES (1989); Garlick (1987, p. 7); ESI Annual Reports and information supplied by participants.

2 The reserve plant margin is the percentage of spare generating capacity above maximum demand in a given period. While widely accepted and used internationally, it is no more than a quick and convenient, though approximate, way of assessing whether a utility or an interconnected pool has an excess or deficiency of generating plant to reliably meet its expected peak load. It does not take into account plant mix, load types, systems' ability to meet loads throughout the year, and many other factors which are properly included in a rigorous assessment of plant capacity. Comparisons made between utilities on the basis of RPMs are therefore no more accurate than the approximations and assumptions implicit in the definition of RPM. This issue is discussed further in Chapter 4.

In spite of closures and recent demand increases, the RPM for ECNSW - which generates around a third of the nation's electricity - was still only a little under 50 per cent in 1989-90. While ECNSW forecasts that its RPM will fall to a little over 30 per cent in 1991-92, the commissioning of units at the new Mt Piper station could increase the RPM in subsequent years unless matched by further plant closure.

In some states, productive efficiency has been compromised by the use of relatively high cost generating plant at times when capacity has been available in lower cost plant. For example, a report prepared by Intelligent Energy Systems (1989, p. 53) commented that, in order to sustain regional employment, some power stations on the Central Coast of New South Wales are utilised in preference to lower cost Hunter Valley stations (eg Bayswater).

Substantial reductions in staffing levels by a number of authorities are also indicative of excessive production costs over much of the 1980s. Data provided by the ESAA show that employment in the Australian ESI fell from around 75 000 to just over 66 000 in the two years to June 1990. (The extent to which this decrease has been offset by increased use of external contractors is unknown.) A major factor in this decline was a reduction in ECNSW's workforce during this period of over 30 per cent. Information submitted by participants indicate that further significant reductions in the ESI workforce are possible and planned.

A report by the New South Wales Department of Energy (1988) found that considerable overstaffing existed in the electricity distribution sector in New South Wales. After allowing for differences in functions and working hours, it found that the customer-employee ratio for the then Sydney County Council was 144 compared with 237 for the London Electricity Board. It also reported that employees of county councils enjoy employment conditions ‘well above community standards’.

Data submitted by the New South Wales Government compared the performance of the New South Wales distribution sector with the South-East Queensland Electricity Board (SEQEB) and United Kingdom Area Boards. It shows that, at June 1989, the ratio of customers to employees for New South Wales was significantly less favourable than for SEQEB and the UK Boards (125 compared with 204 and 322 respectively).

Gas

There is only limited information available to the Commission about the performance of the natural gas industry over the past five years or so.

Ratios such as sales volumes per employee and customers per employee are sometimes used as indicators of efficiency. These are shown in Table 3.2 for the three major reticulation utilities in Australia - GFCV, AGL Gas Companies (AGL) and Sagasco.

Table 32: **Performance indicators for gas utilities, 1989-90**

Indicator	*GFCV*	*AGL*	*Sagasco*
Sales volume (TJ) Per employee	26.8	36.2	35.4
Customers per employee	194	211	289

Source: Annual reports and information submitted by participants.

While the data show considerable variation in the ratio of customers per employee, the comparability of the data is affected by a range of factors including the density of the distribution network and the extent to which work is contracted out. Nevertheless, given the high penetration rate of the GFCV, particularly in the Melbourne suburban area, and its low ratio of customers per employee relative to AGL and Sagasco, the data suggests that the GFCV - Australia's largest gas utility - is performing poorly relative to the other two utilities.

A study by the Economic and Budget Review Committee of the Victorian Parliament (1990) recently examined the operations of the GFCV. It reported (p. 190) that there is ‘substantial scope for improvement in the Corporation's [GFCV] operational efficiency’. The study found it ‘unacceptable’ that the GFCV had increased staff numbers by 8 per cent over the four year period to June 1989. The report (p. 206) noted that:

> During this period there is no evidence that the Corporation has embarked on new activities or significantly expanded its current activities.

The GFCV's employment continued to increase in 1989-90. At 30 June 1990, it was 6129 - about 2.5 per cent higher than employment at 30 June 1989.

In concluding, the Economic and Budget Review Committee (p. 218) stated:

> The GFCV has a natural monopoly on the sale of natural gas in Victoria ... has operated in an environment of relatively low input prices ... [and] operates in an industry which has significant economies of scale. These circumstances appear to have engendered a comfortable situation for the GFCV in which there has been little incentive to implement the policies and procedures for improvements in efficiency and effectiveness ...

A comparison of AGL with 16 selected United States gas companies submitted by the New South Wales Gas Users Group shows that AGL's ratio of assets to sales is inferior to all of the nominated United States gas utilities. However, no information was available to examine the comparability of the activities of the different overseas gas utilities (eg detail concerning the density of the network).

Allocative efficiency

Electricity

Information submitted by participants and previous reports show that the pricing policies pursued by public electricity authorities have not been consistent with efficient pricing principles, mainly because they have not accurately reflected supply costs. Uniform pricing irrespective of location and cross-subsidies between different classes of users are major factors contributing to this outcome.

Differences in prices charged to different user groups can be indicative of the use of Ramsey pricing. However, in the case of electricity, observed differences cannot be construed as Ramsey pricing as tariffs favour residential users whose demand for energy is not very responsive to variations in price.[3] Ramsey pricing would involve residential users being charged relatively high prices, with other users whose demand is more ‘elastic’ being charged lower prices (eg some manufacturers and exporters).

Evidence of shortcomings in pricing include:

- A 1989 SECV tariff review estimated that revenue exceeded the cost of supplying Victorian commercial users by around 28 per cent. In contrast, revenue raised by domestic users was 15 per cent less than the cost of supply. The SECV estimated that the cross-subsidy in favour of domestic users amounted to $177 million in 1987-88.

- In a submission to this inquiry, the New South Wales Government stated that a recent report by the Electricity Council Working Party (1989) identified many instances in New South Wales where customer classes were paying less than 50 per cent or more than 150 per cent of allocated supply costs. The New South Wales Government also stated that the bulk supply tariff involves ‘a considerable amount of averaging of costs both daily and seasonally’:

- The New South Wales Committee of Inquiry into Electricity Tariffs and Related Matters (1989, p. 17) commented:

  > The industry ... makes one class of consumer ‘subsidise’ another class. For example, Councils charge Industrial and Commercial consumers at a rate on average about 17 per cent greater than the domestic consumer. One estimate of the amount necessary to equalise these tariffs is in the order of $167 million per annum.

- ACTEW estimated that the cross-subsidy from commercial users in favour of domestic users within the ACT amounts to about $30 million annually.

- The Working Party to Review Energy Pricing and Tariff Structures (1987) reported that, apart from off-peak tariffs, there was no time-of-use tariffs available in South Australia.

[3] See Lilio (1989)

- SECWA submitted to this inquiry that ‘owing to uniform tariff policies, most customers in country areas pay less than the actual cost of supply’. According to SECWA (1990, p. 13), its uniform tariff policy results in it ‘losing an estimated $38 million of revenue per year in country areas.’

Poor financial performance is reflected in high debt/asset ratios reported in the accounts of some electricity authorities. For example, based on its accounting conventions, SECWA had debt levels over 20 per cent greater than net assets in 1989-90 (ie it was technically bankrupt).

Gas

There is also evidence that tariffs for gas transmission and reticulation have not closely reflected supply costs.

- All major natural gas utilities are required to discharge CSOs. These include uniform pricing, subsidies to domestic users and pensioner rebates (see Appendix 3). As most have to be funded internally, a complicated network of cross-subsidies has evolved. As a result, charges cannot accurately signal supply costs to users.

- The New South Wales Gas Users Group submitted cost estimates which suggest that AGL's costs of supplying non-industrial users are greater than the corresponding revenue. The group claimed that this shortfall, and AGL's profit margin, is recouped from higher charges applied to industrial users. Based on 1987-88 data, the group estimated a cross-subsidy between industrial and all other users of around $60 million. AGL accepts that cross-subsidisation of some magnitude exists.

- The Working Party to Review Energy Pricing and Tariff Structures (1987) claimed that Sagasco's tariff structures resulted in the industrial and commercial sectors making a significantly higher contribution to overhead costs than other sectors.

- GFCV has been supplying tempered LPG to six Victorian regional towns at heavily subsidised rates for many years.

3.3 Initiatives to improve performance

Following criticism of their performance from external agencies and intra-government reviews, significant changes have been made, or foreshadowed, to the operations and operating environment of public electricity authorities and, to a lesser extent, government gas utilities. Private gas utilities have also implemented new policies to improve performance.

In many respects, Queensland and New South Wales have been at the forefront of change. Queensland provided an example of the possible gains from rationalising staffing levels and work practices in the mid 1980s. At present, New South Wales is providing a lead with its program to corporatise ECNSW. Governments in each of these two states have also passed legislation which substantially alters the regulatory framework applying to private gas utilities.

The programs that have been implemented vary widely between states. They encompass a variety of measures intended to improve:

- managerial efficiency;
- capital productivity;
- labour productivity;
- fuel costs; and
- pricing practices.

Some of the more important initiatives in each of these areas are briefly mentioned below. Appendix 4 provides a more detailed discussion of policy changes to public electricity and gas utilities in each state/territory.

Managerial efficiency

All utilities have implemented policies to improve management efficiency. The greatest changes have been in government owned utilities. The changes are intended to increase the incentive for efficient management by placing utilities on a more commercial footing. This has involved providing greater autonomy to managers, but making them more accountable for utilities' performance. It has resulted in the development of corporate strategies and business plans, flatter management structures, greater delegation of responsibility, the establishment of performance targets and improved budgetary procedures. In some cases, a commercial orientation has been reinforced by the removal of some factors which have traditionally advantaged public utilities (eg taxation exemptions) and those which have hampered performance (eg requirements to comply with public sector employment policies).

The following provides some indication of the scope of reforms that has been employed.

- Subsequent to the enactment of the State Authorities Financial Management Act, the Tasmanian Government is planning to commercialise the Hydro-Electric Commission of Tasmania (HECT) by March 1992. This is intended to provided the HECT with greater autonomy in operational matters, while retaining ministerial control over strategic policy issues (eg pricing and new investment proposals).

- SECWA has introduced a new leaner and flatter management structure providing managers with greater independence. A performance agreement encompassing financial and operational performance targets will be used as a basis for assessing its performance.

- Following the development of a new Corporate Strategy, the SECV has been reorganised into three Strategic Business Units with transfer pricing between units.

- ETSA has embarked upon a ‘Financial Management Practices Improvement Program’ which, among other things, aims to create business units within ETSA, commercialise purchasing activities and establish performance targets and monitoring schemes.

- GFCV has introduced what is termed ‘Total Quality Management’. This is intended to integrate ‘into all levels of the Corporation a continuous review and improvement procedure of all operations’.

- ECNSW is to be corporatised by October 1991. ECNSW is also separating transmission from generation in its financial accounts and is considering the separation of its base load power stations into three geographically based centres.

- Electricity councils in New South Wales have negotiated individual performance agreements with the Government which set out a range of operational objectives and targets. It has recently been reported (Pickard 1991, p. 6) that savings in the order of $40 million have been achieved since their introduction.

- The ACT Administration is in the process of corporatising ACTEW.

Capital productivity

Initiatives to improve capital productivity have included the retirement of plant, new investments to increase technical efficiency, asset sales and greater use of private sector resources. The following examples are typical of such initiatives:

- SECWA's next major power station - a coal-fired plant at Collie - is to be privately built, owned and operated. As part of the agreement to proceed with the plant, concessions were made by the coal companies, miners and SECWA which will result in real reductions in power charges from 1 July 1991.

- AGL is rehabilitating its gas distribution system in Sydney to reduce leakage and increase productivity.

- Power stations in Queensland (Callide A, Tennyson and part of Swanbank) and New South Wales (Tallawarra, Vales Point A and two units at Munmorah) have been decommissioned or dry stored.

- Most electricity authorities have successfully implemented programs to improve the availability of generating plant. Data submitted by the ESAA show that the available capacity factor for southern and eastern mainland states as a whole increased from 69 to 79 per cent between 1986-87 and 1989-90.

- The SECV is advocating the sale of the Loy Yang B power station. It claims that `the introduction of a private power station with its lower operating costs and higher plant performance would have flow-on potential for SEC efficiency'.

- Most authorities have expressed increased interest in purchasing electricity from cogenerators and other private plant. In New South Wales, negotiations are proceeding with private interests to build, own and operate a small generating plant at Gunnedah to supply the state grid. In South Australia, ETSA is negotiating the possible purchase of electricity from a private firm (Penrice Soda Products) which is considering the feasibility of installing a large cogeneration plant at its Osborne factory.

- The SECV has commenced a $55 million study into demand management which it expects will, among other things, permit more efficient utilisation of electrical energy and plant, and thus defer the need for new power stations.

Labour productivity

Reductions in staffing levels have been the major factor underlying increases in labour productivity. However, substitution of ‘in-house’ labour by contract labour and changed work practices have also contributed to higher labour productivity. The policies implemented include:

- HECT has reached agreement with unions to create a single award covering all employees. It also has a commitment to finalise a single pay scale. This will supplant the old system which consisted of 13 separate awards and up to 2500 pay and salary rates. The agreement is expected to result in considerable productivity gains through rationalisation of resources and more flexible working arrangements.

- In Queensland, labour productivity has increased sharply since the mid-1980s through increased use of contract labour and improved work practices. A single award was adopted for the Queensland electricity supply industry in 1990.

- More recently, ECNSW has also substituted contract labour for some in-house employees and eliminated some restrictive work practices. ECNSW negotiated a single award for all of its employees in February 1991.

- AGL expects that award restructuring will help increase labour productivity. It stated that `award restructuring ... provides a key opportunity to reassess what skills will be required to run the business in the future and to take the actions necessary to meet those needs'.

- Employee numbers in the SECV fell by 18 per cent between January 1989 and June 1990.

- In the Northern Territory, PAWA reduced its workforce by 15 per cent between 1983 and 1989. Over this period, electricity generated increased by 50 per cent.

- Employment in the Queensland ESI (including the regional boards) declined from a peak of about 13 200 in June 1984 to 8600 in June 1990.

- ECNSW's employment fell by around 30 per cent in the two years to June 1990. This reduction, coupled with benefits resulting from award restructuring and improved shift work practices, are claimed to have improved labour productivity over that period by nearly 60 per cent (Pickard 1990).

- In 1989, Sagasco introduced an employee share option scheme to help strengthen employee commitment. The offer was accepted by 94 per cent of employees.

Fuel Costs

Initiatives to improve fuel sourcing have included a movement away from state-owned mines and the investigation of alternative fuels.

- ECNSW has been rationalising its coal mine assets. Some mines have been closed. It has also been announced that all ECNSW mines will be sold. ECNSW has received over 30 expressions of interest for the sale of individual mines or groups of mines. The Government expects the initiave to realise savings in the order of $50 million annually.

- QEC has rationalised its coal supply arrangements. A competitive tendering process applies to all fuel purchases.

- PAWA has trialled hybrid diesel/battery systems as part of a program to cut fuel costs in remote power stations.

- Some electricity authorities are investigating the feasibility of using renewable energy. For example, ECNSW is supporting research into photo-voltaics.

Pricing practices

Over the last five years or so there have been some attempts to restructure tariffs so that they are more reflective of supply costs. This has resulted in an increase in the availability of time-of-use tariffs (tariffs which vary according to the time of the day or week electricity or gas is used) and reduced reliance on tariff forms which ignore peak costs (eg block tariffs). In some states, there has been some realignment of tariff levels to achieve modest reductions in the cross-subsidies which exist between end-user groups.

- Following an inquiry in 1989, ECNSW has extensively restructured its bulk supply tariff so that it more closely corresponds with its marginal operating costs.

- In 1988, supply charges were introduced to both ETSA and Sagasco tariffs to reflect more realistically the fixed costs of supply.

- Electricity councils in New South Wales have re-structured retail tariffs to reflect better the bulk supply tariff. At the draft report hearing, the Electricity Council of New South Wales stated that it has a 5 year time frame to eliminate cross-subsidies. The 1990 ministerial directive that the Sydney City Council return $75 to each customer, regardless of size or consumption, was an aberration to such restructuring.

- A two-part tariff consisting of a fixed charge and energy charges up to each user's contracted volume has been adopted by the Pipeline Authority of South Australia (PASA).

- In late 1990, the SECV announced reductions of between 5.5 and 6.5 per cent in three time-of-use tariffs applying to some 1500 industrial users. The SECV expects this will reduce users' costs by $16 million annually.

3.4 The scope for improvement

Although the pace of change has been uneven, there is no doubt that the policies implemented over the last few years have improved efficiency. Nonetheless, information submitted to this inquiry clearly indicates that the electricity and natural gas supply industries are still performing well below their potential.

There is substantial scope for improving productive efficiency, especially by increasing capital utilisation, reducing staffing levels and improving work practices. For example, the RPM in ECNSW - which is by far the country's largest electricity generating authority - is still almost double the level which ECNSW has stated it wishes to achieve. Similarly, a number of utilities indicated that staffing levels need to be reduced. For example, electricity councils in New South Wales plan to reduce employment by about 8 per cent (1250 people) by 1992-93.

There is also significant scope for improvement in pricing practices. Many tariff schedules continue to bear little resemblance to economic supply costs, largely because cross-subsidisation between and within customer classes remains prevalent in all states. While the extent of cross-subsidisation appears to have been reduced in some states, progress is slow. For example, the South Australian Government stated that:

> ... present indications are that the cross subsidies which exist between ETSA's domestic and small commercial customers (currently commercial tariffs are 70 per cent higher than comparable domestic tariffs) will be largely eliminated over the next 7-10 years.

The New South Wales Government explained the slow rate of tariff reform in the following terms:

> There are also limits on the rate at which retail tariffs can be reformed, due to what is essentially an understandable political requirement to limit the impact of reform on individual customer accounts.

Participants' submissions, including those from governments and from utilities themselves, suggest a broad consensus that there is scope for improving the efficiency of the electricity and gas supply industries in Australia. For example, the SECV said:

> Whereas the SECV has achieved major improvements as a result of a number of initiatives, it is still believed that substantial potential exists to further develop these reform actions.

The South Australian Government expressed similar sentiments:

> There clearly are efficiency gains to be made in such areas [pricing and production efficiency] in the electricity supply industries in this State and elsewhere in Australia. Gains are also available within the natural gas industry.

Thus, it is widely accepted that there is scope for improving efficiency. The central focus for the inquiry is, therefore, about identifying an approach which will maximise the probability of attaining the available gains. This is the central theme of Part III of this report. However, prior to this discussion, Chapter 4 discusses the benefits which may be associated with improving performance.

4 THE ECONOMIC BENEFITS OF IMPROVING PERFORMANCE

Improvements in the production efficiency and pricing practices of the electricity and gas industries would have substantial long run benefits for the Australian economy with GDP increasing by $24 billion annually and an extra 8000 jobs being created Most of these benefits come from reform of the electricity supply industry. The mining and minerals processing sectors would be the major beneficiaries of these reforms. While a start has been made on achieving these, fundamental changes to the structure and organisation of the industries are required to provide the appropriate incentives for the bulk of these gains to be achieved and sustained

Significant progress has been made in the last few years in improving the economic performance of Australia's energy supply industries. However, there is scope for considerable improvement and much remains to be done.

Australian electricity generation and distribution systems are still overstaffed and many systems operate at capacity levels well below those levels achievable in Australia and achieved in comparable countries. Consequently, unit supply costs are higher than they need be. Total cost savings of at least $1.2 billion could have been made if international best practice in labour and capital usage had been achieved in 1989-90.

Current pricing practices in the electricity supply industry also impose costs on the community with extensive cross-subsidisation occurring between different groups of users. Although there has been some realignment of tariffs, substantial cross-subsidies between user classes and between users in urban and country regions remain.

To estimate the economy-wide effects of improved electricity production and pricing practices, the following scenarios were simulated using the ORANI model of the Australian economy:

- other states achieve the total factor productivity (TFP) level of the most efficient states, Western Australia and Queensland, in 1989-90;
- all states additionally achieve Queensland's 3 year projected TFP level;
- all states achieve international best practice in labour and capital usage; and
- cross-subsidies are eliminated.

For gas distribution, 15 per cent savings in both unit labour and capital requirements were simulated.

The simulations were carried out in an environment where increased revenues resulting from better electricity and gas production practices were used to reduce taxes on all income by the same proportion. In other words, fiscal neutrality was assumed - the size of the government deficit remains constant in spite of revenue changes.

As discussed below, the ORANI analysis does not form the basis of the Commission's recommendations. Indeed, it is not possible to model the effects of many of the recommendations, such as corporatisation and increased competition, in a model like ORANI. Rather, the ORANI analysis is intended to illustrate the size of the gains which are potentially available from improving the efficiency of the electricity and gas industries.

4.1 Reforms considered

4.1.1 Electricity productivity improvements

The study of state electricity industry productivity by Lawrence, Swan and Zeitsch (1990) indicated that substantial scope existed for productivity improvements and cost savings if the other mainland states had achieved Queensland's productivity levels of 1988-89. A number of participants criticised the study in regard to inaccuracies in the data used. In particular, the SECV disputed the value of fuel inputs and operating costs figures used for Victoria, while SECWA noted that the figures it had supplied to the ESAA actually included its gas as well as its electricity employees. The SECV also claimed that the real rate of return of 8 per cent, used to calculate capital annual user charges in the study, was too high. Other participants (eg ECNSW) claimed that substantial productivity improvements had been made since the end of 1988-89 and, hence, were not reflected in the results of the initial study.

In response to these criticisms, the Commission arranged for Lawrence, Swan and Zeitsch to revise and update their total factor productivity study. The following changes have been made:

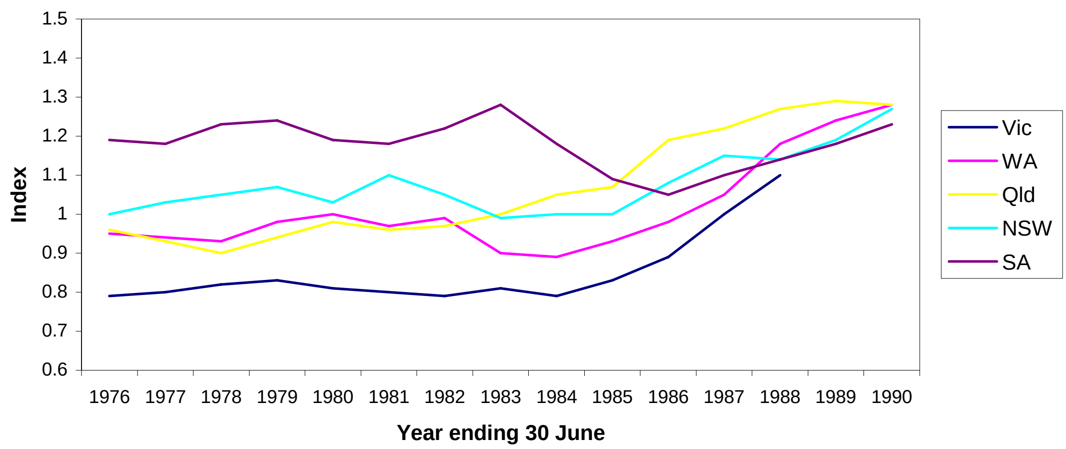
- fuel and operating costs figures for Victoria have been revised in consultation with the SECV and the Victorian Department of Premier and Cabinet;
- SECWA's estimates of its gas employees have been deducted from the labour input and operating cost of Western Australia;
- a sensitivity analysis of the results using 4, 6 and 8 per cent real rates of return has been conducted; and
- the study has been updated to 1989-90 using data received from the ESAA in April 1991, prior to its official publication.

The fuel and operating costs data originally supplied by the SECV incorrectly included some finance and depreciation charges. A significant discrepancy was also found to exist in the Victorian operating cost figure reported by the ESAA for 1988-89.

It is recognised that a number of inadequacies and inconsistencies remain in the data the various states have supplied to the ESAA. Further work has been proposed to eliminate these. However, at this time the ESAA data remain the most comprehensive source of electricity industry data and attempts have been made to remove the errors identified in the data used in the productivity study.

The results of the revised and updated analysis using an 8 per cent real rate of return are presented in Figure 4.1. Following revisions to the data, the performance of Western Australia and Victoria in recent years is better than that shown in the earlier analysis. Extending the analysis to 1989-90 shows that the TFP levels of all states, other than Queensland, continued to increase at or above their trend rates of recent years. New South Wales' TFP level increased above trend with an increase of 8.4 per cent in 1989-90. The gap between the states with the highest and lowest TFP levels continued to narrow in 1989-90.

Figure 4.1: **State electricity multilateral TFP productivity indices - 8 per cent real rate of return**



Source: Lawrence, Swann and Zeitsch (1991)

The results of the analysis are relatively insensitive to the choice of a 4, 6 or 8 per cent real rate of return on capital. The rankings of the states remains largely unchanged. The use of a lower rate of return (and thus the placing of less weight on the capital input in the aggregation process) tends to improve the performance of Victoria relative to the other states, although Victoria still has the lowest TFP levels for all years except 1989-90. The use of a 4 or 6 per cent rate of return favours Queensland relative to Western Australia in recent years, with Queensland retaining its status as the state with the highest TFP level in 1989-90 using the lower rates of return. The drop in Queensland's TFP in 1989-90 is, however, accentuated using the lower rates of return as relatively more weight is then placed on the other inputs category which increased disproportionately in that year.

To model the effects of the other states achieving the productivity level of the most efficient states in 1989-90, the reductions in total input quantities which would be required were weighted together to derive an overall average productivity improvement for the Australian electricity industry. Using the Lawrence, Swan and Zeitsch figures unadjusted for non-choice factors, the resulting reduction in total input use would be 2.4 per cent.

Productivity and efficiency improvements are ongoing and further reforms are underway in Queensland which are expected to lead to even better performance. To simulate the likely effects of these additional reforms, the Commission obtained confidential provisional projections from QEC of expected movements in output and input quantities over the period 1989-90 to 1992-93. These projections indicated that QEC expects to achieve further unit total input savings of 8.6 per cent over this period. The effects of all of the Australian industry achieving these projected productivity levels has been simulated as an 11 per cent saving in unit total input usage (2.4 per cent for the other states to get to the level of the most efficient state in 1989-90, plus 8.6 per cent for all states to then achieve the Queensland projected level). The Commission has not had the opportunity to verify the QEC projections and it should be noted that the capital component is estimated on a different basis to the Swan method used by the Commission. Consequently, the simulations are only intended to be indicative of the order of magnitude of possible additional productivity improvements.

A third scenario for productivity improvement which can be considered is for the Australian industry to achieve international best practice in the usage of labour and capital. This has been modelled as a combination of reduced reserve plant margins and improved labour productivity.

Reserve plant margin is defined as the total plant capacity available less the actual maximum demand for electricity in a particular year expressed as a percentage of the maximum demand. It is not a measure of reliability in itself, but a consequence of installing plant to meet a desired level of reliability in the light of anticipated demands. The appropriate reserve plant margin for a particular system depends on a combination of factors such as load variability, plant size in relation to load, plant forced-outage rates, seasonal load variations and the desirable level of reliability in the system. Current utility practice is to employ statistical programs which calculate the loss of load probability and/or the expected unnerved energy as the major criteria for planning decisions.

Excessive installed generation plant increases the size of capital stock and thus raises the costs of electricity supply. To get some indication of these additional costs for the Australian state electricity systems, the RPMs for 1989-90 have been compared with the `best practice' figure of around 20 per cent recommended by the IEA, a figure which corresponds to the bottom end of the 20 to 35 per cent range accepted by ECNSW (ECNSW 1989, p. A5). Results by state are given in Table 4.1. Some countries, such as Japan, have achieved significantly lower RPM levels. Over the period 1983 to 1986, the RPM for the Japanese ESI averaged 12.6 per cent (JEPIC 1987).

Based on the calculations relating to 1989-90 in Table 4.1, excess RPMs in Australian electricity systems resulted in the employment of 12 per cent more capital than was necessary for least cost operation. This excess capacity inflated electricity supply costs in the mainland states by 10 per cent or $800 million in 1989-90. This is, nonetheless, an encouraging reduction from the $1 billion excess in 1988-89 estimated in the draft report.

The estimate of excess capacity derived from RPMs depends partly upon the maintenance of existing pricing practices. If, however, authorities introduced pricing regimes which were to reduce peak demand significantly, then capital requirements and costs in the industry could be significantly reduced. It could be argued that in compiling estimates which compare the situation in Australia with international best practice, it would be preferable to incorporate both preferred reserve plant margins and efficient pricing practices which are designed to manage peak demand optimally. Because sufficient data on best pricing practices were not available, the estimates above implicitly assume that current pricing practices best manage peak load demand. However, greater use of peak load pricing to reflect the higher cost of peak loads and other improvements in pricing practices would reduce the size of peak demand, and the above estimates therefore understate the extent and cost of current excess capacity.

A number of participants criticised the use of RPMs as a measure of excess capacity and disputed whether an RPM of 20 per cent is a realistic target for Australian states. For example, the Queensland Government indicated that, given its situation, an RPM of 25 per cent was the best is could aim for. It stated that lower RPM targets were usually used in larger systems and depended on the availability of generating sets and the pattern of demand for electricity.

Table 4.1: **Estimated excess capital stock associated with 1989-90 reserve plant margins**

	NSW	*Vic*	*Qld*	*SA*	*WA*
Reserve Plant Margin 1989-90 (per cent)	46	27	37	45	25
Assumed Best Practice (per cent)	20	20	20	20	20
Excess Capital Stock (per cent)[a]	18	5	12	17	4
Capital Annual User Charge (8% real return) ($m) 1989-90	2 487	1 978	1 272	452	440
Cost of Excess Reserve Plant Margins ($m)	443	109	158	78	18

a Calculated as; 100 x (Existing RPM - Optimal RPM)/(100 + Existing RPM).

Sources: Table 3.1 and Lawrence, Swan and Zeitsch (1991).

As noted above, the Commission accepts the shortcomings of the RPM measure, but those participants who have criticised the measure have failed to produce practical alternatives for the purposes of the current study. The Commission is retaining the RPM target of 20 per cent in this analysis as an indication of what might ultimately be achievable in Australia. This may well involve eventual amalgamation of state systems to avoid the limitations currently claimed to exist. In fact, SECV system planning studies indicate that the RPM in Victoria will be around 15 per cent under normal weather conditions and with anticipated installed plant and interconnections within 20 years.

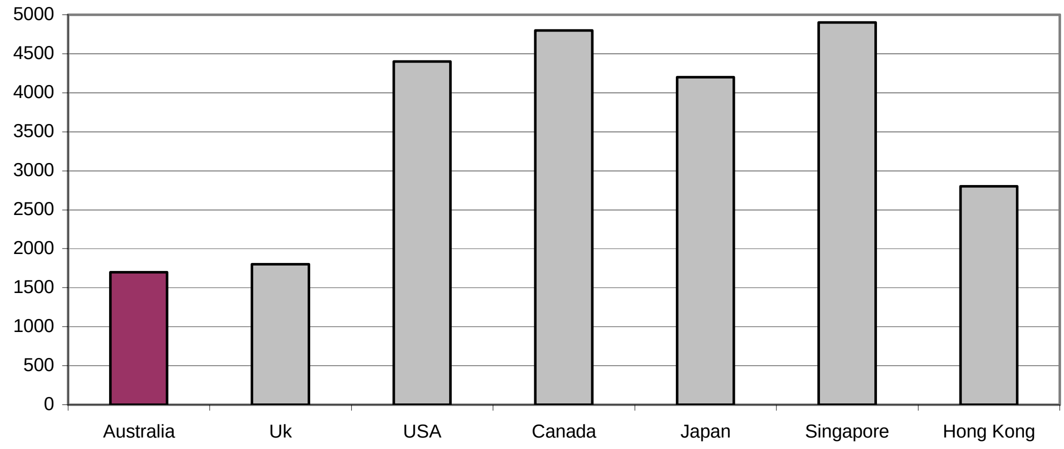
ECNSW criticised the Commission's assumption that the same degree of excess capacity exists in transmission and distribution assets as that observed in generation based on the RPM figures. However, the Commission considers this to be a more reasonable assumption than the alternative proposed by ECNSW that no excess capacity exists in transmission and distribution capital stocks.

Employment in state electricity authorities has declined significantly in recent years and most states plan to make further significant reductions. Tasmania, for instance, plans to reduce its electricity labour force by 48 per cent over a period of 8 years. In New South Wales, shedding of excess labour has mainly been confined to ECNSW, the generating and transmission authority. The labour intensive distribution authorities have only recently been subjected to pressure to improve their efficiency. Supplementary evidence supplied by the ESAA indicated that the Australian industry was aiming to increase its labour productivity (as measured by GWh sold per employee) by one-third between 1988-89 and 1992-93.

A comparison of international output levels sold per employee is presented is Figure 4.2. While the link between these figures and labour productivity is less than certain due to different utilisation of contracting between countries and other differences in supply and demand conditions, Australia lags behind the countries shown.

Taking into account long term employment targets of the various Australian authorities and comparisons with other countries, reductions in unit labour inputs of at least 25 per cent would be required before the Australian industry could be considered equal to the best in the world. This would have provided cost savings of $380 million in 1989-90.

Figure 4.2: **International output sold per employee** (MWh/Employee)



Sources: **Annual reports of respective electric power bodies and energy authorities.**

Modeling the attainment of international best practice by reducing reserve plant margins to 20 per cent and reducing unit labour requirements by 25 per cent is likely to understate the potential gains to Australia as productivity improvements for inputs other than labour and capital have not been included. Savings in material and services inputs and fuel inputs would also be available.

4.1.2 Elimination of electricity cross-subsidies

Pricing policies have been used as a means of providing energy at concessional rates to some users at the expense of others. The most comprehensive information available on the extent and pattern of cross-subsidies is for Victoria (SECV 1989). According to these figures (reproduced in Table 4.2), low-voltage business users are currently over-charged for electricity relative to the costs of supply while domestic users, the farm sector and high voltage business users are under-charged. Energy-intensive industries' prices are claimed just to cover the costs of supply.

Table 4.2: **Price changes to eliminate claimed cross-subsidies**

User Group	*Price Change (%)*
Domestic	23.2
Farm	118.1
Business (low voltage)	-26.2
Business (high voltage)	11.2
Total business	-18.5
Energy intensive industry	0.0
Community service and public lighting	-7.3

Source: Derived from SECV (1989)

A number of participants (eg the Queensland Government) claimed that the Victorian figures were unlikely to be representative of the situation in other states. However, in the absence of comprehensive information on the extent and pattern of cross-subsidies in other states, the information for Victoria has been assumed to be representative for Australia as a whole. It has been used to apply a differential set of price changes in the ORANI simulations sufficient to leave electricity prices unchanged on average, while at the same time eliminating the cross-subsidies claimed to exist in Victoria. It should be noted that the same relativities as found in SECV (1989) have been retained, but some rescaling was necessary due to the different composition of electricity use in the ORANI database compared with the SECV's sales pattern. Additionally, the Commission has been unable in the time available to verify the SECV figures. The figures will be sensitive to the method of allocating joint costs. Furthermore, the SECV's estimates of capital costs differ greatly from the Swan (1990) annual user charges used by the Commission. Consequently, the simulations representing the removal of cross-subsidies are only intended to provide estimates of the broad orders of magnitude involved.

4.1.3 Gas productivity improvements

Due to the small amounts of available research into the gas supply industry, it is not possible to undertake simulations of the same degree of detail as it is for the ESI. In addition, given the structure of the ORANI model and the time available it has only been possible to concentrate on the gas distribution industry.

Each of the utilities involved in gas distribution has registered productivity improvements in recent years. For example, over each of the past eight years, AGL

Sydney has increased sales per km of main by five per cent per year (on a compound basis) and raised labour productivity, in terms of tariff sales per employee, by 10 per cent per year (on a compound basis). In Victoria, the GFCV has reduced its controllable operating costs per customer by about 10 per cent in real terms over the last five years. In the United Kingdom, British Gas continues to achieve significant productivity improvements. From 1992 to 1997 its annual average price increases are being restricted to the retail price index less five percentage points. On the basis of recent productivity gains from some utilities and the potential for further productivity improvements (including confidential evidence from AGL), the Commission estimates conservatively that unit labour and capital requirements in the gas distribution industry could, in the longer term (say 10 years), be reduced by a further 15 per cent in aggregate.

4.2 Specification of the ORANI model

The simulations were undertaken with a long run linear version of the ORANI model of the Australian economy, known as Fiscal-Horridge-ORANI. Fiscal-Horridge-ORANI is an extended version of the ORANI model, designed to improve the model's treatment of taxes and transfers, and of the determination of the main components of aggregate demand (Dee 1989). Since it distinguishes pre-tax from post-tax incomes, Fiscal-Horridge-ORANI can provide a better treatment than standard ORANI of the supply of factors of production. Workers are assumed to make labour supply decisions on the basis of their non-labour disposable income. Investors (both Australian and foreign) are assumed to decide which investment projects to fund on the basis of their post-tax rate of return.

For the electricity industry simulations, the ORANI-MINE level of industry aggregation was used. In this database there are a total of 79 industries, including 14 mining and 12 minerals processing industries. The added detail in mining and minerals processing of ORANI-MINE is useful for the electricity simulations given that many of these industries are intensive users of electricity. A natural resource constraint was introduced into the mining industries and an implicit supply elasticity of 10 was imposed.[1]

The ORANI-MINE level of aggregation was not suitable for examining the effects of gas distribution productivity improvements since it combines gas distribution and water distribution. For the gas distribution simulations, the same level of aggregation was used as in IAC (1989), where gas distribution is separately identified.

With any application of ORANI, the macroeconomic environment in which industry is assumed to operate must be specified. In the scenarios reported here:

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1 It should be noted that this differs from the version of ORANI-MINE used in the Commission's recent report on Mining and Minerals Processing, where an adjustment costs mechanism was imposed on all industries and a simulated database update to 1986-87 undertaken.

- industry and economy-wide stocks of capital were varied so as to maintain given real rates of return in each industry;

- occupational wage rates were adjusted to clear the labour market in each occupational category (assuming fixed rates of frictional unemployment); and

- tax rates were adjusted to maintain real government sector borrowing requirements.

It should be emphasised that the simulations reported in this chapter using the ORANI model are only intended to be indicative of the potential order of magnitude and patterns of effects resulting from improved productivity and pricing in the electricity and gas. industries. The results of the ORANI analysis do not form the basis of the Commission's recommendations. Indeed, it is not possible to model the effects of many of the recommendations, such as corporatisation and increased competition, in a model such as ORANI. Rather, the recommendations which the Commission has arrived at are seen as being the most effective means (given current constraints) of moving the energy industries towards international best practice and, hence, of achieving some of the potential gains identified in this chapter.

Conversely, the effects of some of the recommendations made in this report have not been explicitly modelled. For instance, despite the prospects for achieving cost savings, prices in the short run could increase as utilities are put on a commercial footing (eg required to meet rate of return targets, pay dividends to governments and pay all relevant government taxes and charges). However, the additional revenue would accrue to state/territory .governments and could be used to offset other government taxes or charges.

Finally, it should be noted that the simulations reported in this chapter are of a comparative static nature. This means that the economy is initially assumed to be in equilibrium and a shock is then applied. All other exogenous influences remaining unchanged, the economy reaches a new equilibrium and the situation in this new equilibrium is compared to the initial equilibrium. Thus, in the case of the gas productivity improvement of 15 per cent, the initial situation is compared with a new equilibrium where the gas distribution industry is 15 per cent more productive and all other exogenous factors have remained constant. The 15 per cent productivity shock is thus a one-off change - it has no time dimension to it.

4.3 Results

4.3.1 Electricity productivity Improvements

The macroeconomic, sectoral and selected industry results of implementing various productivity reforms are presented as Scenarios 1, 2 and 3 in Table 4.3. Scenario 1 assumes improved productive efficiency based on the other states achieving the TFP level of the most efficient states, Western Australia and Queensland, in 1989-90. Scenario 2 extends this by assuming all states achieve QEC's projections for the period 1989-90 to 1992-93. Scenario 3 attempts to model international best practice by specifying 20 per cent reserve plant margins and a 25 per cent improvement in labour productivity.

Table 4.3: **Estimated long run effects of electricity supply productivity reforms** (percentage changes)

VARIABLE	*SCENARIO 1 Increased Productivity-1989-90 Best Level*	*SCENARIO 2 Increased productivity – QEC Provisional Projections*	*SCENARIO 3 International Best Practice*
Macroeconomic aggregates			
Real GDP	0.07	0.34	0.48
Real consumption	0.08	0.37	0.46
Real investment	0.00	0.01	0.28
Export volume	0.11	0.49	0.73
Import volume	0.03	0.14	0.30
Balance of trade[a]	0.01	0.05	0.05
CPI	-0.03	-0.12	-0.21
Real pre-tax wage rate	0.11	0.49	0.72
Aggregate employment (persons)	0.01	0.06	0.10
Aggregate capital stock	0.00	0.01	0.28
Shift in direct taxes	-0.04	-0.17	-0.58
Sectoral output levels			
Agriculture	0.00	0.01	0.05
Mining	0.08	0.35	1.60
Manufacturing	0.03	0.15	0.39
Services	0.07	0.31	0.50
Electricity industry variables			
Output	0.47	2.15	3.23
Price	-2.11	-9.60	-14.17
Labour usage	-1.97	-8.97	-19.65
Capital usage	-1.96	-8.92	-10.03
Output of selected industries			
Aluminium smelting	0.36	1.66	2.73
Ferrous metal ores	0.38	1.71	2.81
Cotton ginning, wool tops	0.10	0.47	0.74
Copper smelting and refining	0.17	0.76	1.41
Basic iron and steel	0.00	-0.01	0.26
Basic chemicals nec	0.09	0.43	0.78

[a] Change in the balance of trade as a percentage of base-case GDP.

Achieving the TFP level of the most efficient states

Improved productive efficiency in this scenario involved a uniform 2.4 per cent reduction in the electricity industry's unit requirements of labour, capital, fuel and intermediate inputs. These cost savings reduce electricity prices by 2.1 per cent, leading to a 0.5 per cent increase in the demand for electricity.

All sectors of the economy benefit from lower electricity prices. However, cheaper electricity prices principally benefit those industries which are relatively intensive users of electricity and which receive low levels of assistance. Thus:

- mining industries benefit significantly with ferrous metal ores output increasing 0.4 per cent and sectoral output expanding by 0.1 per cent;
- manufacturing output expands with increases being concentrated on lightly assisted minerals processing activities;
- agricultural output increases only marginally as farmers are not intensive users of electricity and cheaper electricity prices barely offset increased labour costs; and
- largely as a result of the expansion of relatively lightly protected industries, real GDP and real consumption both expand by over 0.1 per cent in this scenario. The growth in the economy facilitates increased output of the services sector.

Real investment expands by a much smaller amount in this scenario as a general increase in demand for capital goods associated with expansion of the economy is almost offset by a reduced demand for capital in the electricity industry.

Export volume increases by 0.1 per cent in response to larger mining and minerals processing outputs. The increase in import volume is much smaller, leading to an improvement in the balance of trade.

A small decrease in direct tax rates is observed in Scenario 1. Reduced capital stocks in electricity generation lead to a net increase in government revenue from this source as reduced interest and depreciation charges offset lower returns from a smaller capital stock. This increase enables government to reduce average tax rates without expanding its public sector borrowing requirement.

Achieving Queensland projections

This scenario involves the 2.4 per cent reduction in electricity industry unit input requirements, as in Scenario 1, plus a further 8.6 per cent uniform reduction in unit input requirements based on QEC's provisional projections for the period 1989-90 to 1992-93. Implementing these cost savings results in 0.3 and 0.4 per cent economy-wide increases in real output and real consumption, respectively. Electricity prices fall by nearly 10 per cent. The results follow the same pattern as those of the first scenario, but with a larger magnitude due to the larger size of the productivity improvement. Since the total cost savings are over 4 times the initial cost savings in Scenario 1, export volumes increase by 0.5 per cent in this scenario. This is due to larger increases in the activity levels of all sectors, with mining and manufacturing expanding by 0.4 and 0.2 per cent, respectively.

Again, all sectors of the economy benefit. Aluminum smelting is one of the major gainers in the manufacturing sector. Lower electricity input costs enable it to increase output by 1.7 per cent.

Achieving international best *practice*

In this scenario, reserve plant margins and labour inputs in the electricity industry are reduced to levels in accord with international best practice. The combined effect of these efficiency improvements is a 14 per cent drop in electricity prices and a 3 per cent increase in electricity sales.

As a result, there is a 0.5 per cent increase in both real GDP and consumption. The pattern of results is largely similar to the preceding scenario, although variations occur as differential reductions are made to unit input requirements (with no reduction for intermediate inputs). Again, the mining and manufacturing sectors benefit significantly from this scenario because they are more intensive users of electricity. As in the first and second scenarios, export volumes increase and, in spite of a larger increase in import volumes, a modest improvement in the balance of trade is observed. A larger reduction in direct tax rates is possible in this scenario. This stimulates greater investment and a larger increase in the aggregate capital stock. The labour productivity improvement is simulated to increase real pre-tax wage rates by 0.7 per cent while reducing the CPI by 0.2 per cent.

All sectors benefit in this scenario. Output increases of 1.6, 0.4 and 0.5 per cent are observed in the mining, manufacturing and services sectors, respectively. Agriculture again shows a modest increase, since electricity is a relatively unimportant input for most farmers. Within the manufacturing sector, aluminum smelting expands the most with an increase in output of 2.7 per cent.

Reaching the long run situation

The results reported above represent the percentage changes between the 1989-90 situation and the new equilibrium once the Australian electricity industry has achieved international best practice. However, there are a number of alternative routes between these two endpoints. One would be to progressively scrap excess capacity. Another would be to sell off excess capacity to the highest bidder and allow free and open competition in the supply of electricity. It is the latter route which is advocated in this Report. If excess capacity was sold off, increased supplies of electricity would be generated. This could be expected to lead to large short run falls in the price of electricity. Over time, however, current capacity would reach the end of its economic life and need to be replaced. Electricity prices would then rise compared to their low short run levels as replacement plant was brought on-line at replacement cost.

The Swan (1990) method of valuing capital inputs, used by Lawrence, Swan and Zeitsch and used as the basis of calculating cost savings quoted in this chapter, converts all relevant past investments to current prices and then calculates the annual charge for those investments necessary to generate an 8 per cent real return. The failure of all state electricity systems to cover costs, including this 8 per cent real return on the cost of past investments, reflects their bad performance in recent decades. Instead of being interpreted as earning less than an 8 per cent real return on the cost of past investments, this could alternatively be interpreted as earning an 8 per cent real return on a significantly lower valued capital stock. In other words, the effect of bad performance in recent decades is reflected in a huge capital loss which the community has had to bear on the value of its electricity supply assets. The magnitude of this incurred, but not yet realised, loss would become apparent when major plants excess to current requirements were put up for auction and attracted only very small bids, reflecting commercial rates of return. On the other hand, the prices achieved from these sales would reflect the better (more intensive) use which the purchasers could extract from the capital compared to the utility. Similarly, a private sector based supply system would only undertake replacement investment if it thought it could earn a commercial return on the cost of new capacity. Thus, in the long run, electricity prices would have to be high enough to generate a commercial return on the full replacement cost of capacity.

The ORANI model does not capture many of the dynamic benefits flowing from increased competition. However, it cannot be assumed that, simply because electricity prices could, in these circumstances, fall substantially in the short run, there will be massive investment in electricity intensive industries such as aluminum smelting. Rational investors will realise that electricity prices would have to be high enough in the long run to provide a commercial return on the replacement cost of capacity and would make their investment decisions accordingly.

4.3.2 Elimination of electricity cross-subsidies

The long run effects of eliminating electricity cross-subsidies while retaining the same level of electricity prices on average are presented as Scenario 4 in Table 4.4. Eliminating cross-subsidies has a favorable effect on the economy as a whole with real GDP increasing by 0.2 per cent per annum. This comes about as a result of electricity prices to business users being lowered while prices to the household sector and agriculture are increased. Business users respond by increasing output. This leads to a large expansion in the output of the mining sector and manufacturing (which includes minerals processing). Mining and minerals processing are readily able to expand production following an increase in competitiveness given their export demand conditions. Agricultural output is less responsive to increases in the price of electricity as agriculture is generally not an intensive user of electricity and it faces less responsive demand conditions than does mining. As a result, under this scenario, its output falls by only 0.3 per cent in spite of the large increase in electricity prices.

Removing cross-subsidies has little impact on prices, wages or employment levels. The output of electricity falls by nearly 9 per cent as usage patterns change. The output of aluminum smelting also declines, even though the price of electricity to aluminum smelting remains unchanged. This is because other processing and manufacturing industries which compete for resources with aluminum smelting enjoy reductions in electricity prices and are better able to compete for resources.

4.3.3 Overall electricity reform

The effects of achieving international best practice in electricity production combined with pricing reforms to eliminate cross-subsidies are presented in the last column of Table 4.4. The combined reforms have a large impact on real GDP with a long-run increase of 0.7 per cent per annum. Real consumption, investment and exports all increase markedly while the CPI falls. Real wages increase as do employment and the aggregate capital stock. The mining sector is again the major beneficiary, followed by manufacturing and services. Output of ferrous metal ores expands by 7 per cent. The output of electricity falls by 5 per cent while its price falls by 14 per cent.

Table 4.4: **Estimated long run effects of electricity productivity and pricing reforms**
(Percentage changes)

VARIABLE	*SCENARIO 4 Removal of Cross - Subsidies*	*TOTAL Scenario (3) plus Scenario (4)*
Macroeconomic aggregates		
Real GDP	0.17	0.65
Real consumption	-0.10	0.36
Real investment	0.02	0.30
Export volume	1.01	1.74
Import volume	0.11	0.41
Balance of trade [a]	0.13	0.18
CPI	0.00	-0.21
Real pre-tax wage rate	0.00	0.72
Aggregate employment (persons)	0.00	0.10
Aggregate capital stock	0.02	0.30
Shift in direct taxes	0.00	-0.58
Sectoral output levels		
Agriculture	-0.34	-0.29
Mining	2.06	3.66
Manufacturing	0.32	0.71
Services	-0.11	0.39
Electricity industry variables		
Output	-8.69	-5.46
Price	0.00	-14.71
Labour usage	-8.76	-28.41
Capital usage	-8.66	-18.69
Output of selected industries		
Aluminium smelting	-1.13	1.60
Ferrous metal ores	4.07	6.88
Cotton ginning, wool tops	0.47	1.21
Copper smelting and refining	1.96	3.37
Basic iron and steel	0.27	0.53
Basic chemicals nec	1.02	1.80

[a] Change in the balance of trade as a percentage of base-case GDP.

4.3.4 Gas productivity improvements

The long run effects of a 15 per cent reduction in unit labour and capital requirements in gas distribution are presented in Table 4.5. As with electricity industry productivity improvements, the economy benefits from greater efficiency in gas distribution but to a lesser extent due to the relatively small size of the industry. Real GDP increases by 0.04 per cent or nearly $150 million in 1989-90 values. Real consumption, investment and export volumes all increase marginally.

Table 4.5: **Estimated long run effects of improved productivity in gas distribution (percentage changes)**

Variable	*Increased Labour and Capital Productivity*
Macroeconomic aggregates	
Real GDP	0.04
Real consumption	0.04
Real investment	0.02
Export volume	0.06
Import volume	0.00
Balance of trade [a]	0.00
CPI	-0.03
Real pre-tax wage rate	0.07
Aggregate employment (persons)	0.01
Aggregate capital stock	0.02
Shift in direct taxes	-0.06
Sectoral output levels	
Agriculture	0.00
Mining	0.08
Manufacturing	0.05
Services	0.05
Gas industry variables	
Output	2.08
Price	-8.68
Labour usage	-12.94
Capital usage	-12.90

The productivity improvements lead to a 9 per cent fall in the price of distributed gas and a 2 per cent increase in its output. Industry effects are generally very small with the mining sector again being the main beneficiary, although with an output expansion of less than 0.1 per cent.

4.4 Summary

Australia's electricity utilities have made significant improvements recently in efficiency. However, there is considerable scope for further improvements in efficiency levels. If international best practice levels of capital and labour were reached, cost savings of at least $1.2 billion would be made.

If the other state electricity systems were to achieve the total factor productivity level of the most efficient state in 1989-90, real GDP would expand by at least 0.07 per cent annually. All sectors of the economy would benefit, with the mining sector being the major beneficiary. If, in addition, all states were to achieve Queensland's projected TFP improvements for the period 1989-90 to 1992-93, an annual expansion of 0.34 per cent in real GDP would result. Achieving international best practice levels of capital and labour usage would lead to an annual expansion of 0.48 per cent in real GDP.

Eliminating cross-subsidies has a favorable impact on the economy with the mining and minerals processing industries being the major beneficiaries.

Significant productivity improvements are also possible for the gas distribution industry. The effects of gas productivity improvements on the economy are small due to the small size of the industry, but national output would nonetheless expand leading to increased living standards for Australians.

Net effects

The net effects of better production practices and pricing in electricity supply and gas distribution could, in 1989-90 values:

- expand national output by $2.4 billion annually ($2.25 billion from electricity reform and $150 million from gas reform);
- increase annual disposable income by around $300 per household;
- lower income taxes by 0.6 per cent; and
- create about 8000 extra jobs.

Fundamental changes to the structure and organisation of the Australian electricity industry are required to provide the appropriate incentives for the bulk of these gains to be achieved and for the gains to be sustainable. The nature of these changes is considered in the following chapters of this report.

5 A CORPORATE MODEL FOR PUBLIC UTILITIES

Administrative reform (or 'corporatisation') seeks to place public electricity and gas utilities on a more commercial footing. If implemented fully, it has the potential to improve efficiency. To date, it has proceeded at a different pace and in different ways throughout Australia This creates the possibility that not all of the gains will be captured This chapter outlines the major components of a corporatisation model which, if implemented as a package, would maximise the potential gains available through administrative reform.

Corporatisation is a form of administrative change which seeks to improve the performance of public electricity and gas utilities by creating improved incentives for efficient management and a more neutral operating environment between utilities and private sector enterprises. It encompasses initiatives aimed at replicating many of the commercial incentives which apply to private firms, but excludes changes in ownership.

All governments are in the process of making some administrative changes to their electricity and gas utilities. The objective of improving efficiency is common to all. The general direction of change - towards a more commercial orientation - is also common to most.

Some public utilities (eg ECNSW and AC I EW) are in the process of being corporatised and some are being comercialised (eg HECT), but the extent of change that has been foreshadowed or implemented by some governments is relatively small. Moreover, it is important to recognise that the administrative changes proposed by governments fall well short of what the Commission considers necessary if all of the benefits obtainable from administrative change are to be realised. For example, while the Commission considers the removal of all legislative barriers to entry a cornerstone of any corporatisation program, such barriers will still apply to transmission after ECNSW is corporatised. This will prevent users in New South Wales from exploiting opportunities to purchase electricity more economically by connecting with suppliers in adjacent states. Corporatisation in Queensland, as outlined in the Government's Green Paper, envisages existing legislative barriers to entry to all industry activities remaining in place.

Commercialisation programs have more significant limitations. For example, the Tasmanian program would, as well as maintaining legislative barriers to entry, retain 'ministerial control on strategic policy issues' (eg pricing and investment decisions), fail to provide HECT with objectives that relate to commercial performance only, continue to provide it certain advantages which are unavailable to private enterprises (eg exemption from some taxes and from the provisions of the Trade Practices Act) and require that it continue to conform with certain general public sector policies (eg government employment and industrial relations policies).

Despite these shortcomings, the reforms currently in train or in prospect should result in greater uniformity in states' policy frameworks. Nonetheless, it would appear that significant differences could remain in the institutional and regulatory frameworks applied to electricity and gas. Such differences between governments may lead to production and investment decisions which, from a national perspective, hinder rather than aid the efficient development of the industries.

This chapter outlines the Commission's views on the major components of a corporatisation model which it considers would, if implemented as a package, accelerate the reform process and increase the likelihood of realising all of the potential gains. The Commission considers the model could, and should, be applied to public utilities in all states/territories, irrespective of differences that may exist in industry structure and operational conditions. For example, the Commission considers that the model is, with minor modifications (see page 73), just as applicable to electricity councils in New South Wales as it is to ECNSW.

This chapter considers a number of elements in turn, commenting on the shortcomings of previous arrangements and proposing alternative measures. The discussion commences with a brief outline of the basic philosophy underlying corporatisation.

5.1 Rationale underpinning corporatisation

Corporatisation addresses shortcomings in the incentives required for the efficient management of public enterprises. Some, but by no means all, are related to constraints associated with public ownership. For example, in private enterprises, exposure to market disciplines usually results in insolvency or takeover with uncertain consequences for management if inefficiencies persist. In contrast, these pressures do not apply to government managers. Public enterprises are not subject to takeover and are unlikely to be declared insolvent, even when technically bankrupt. Further, government managers, unlike their private sector counterparts, have limited opportunities to share directly the benefits associated with improved performance. This has contributed to the development of a culture which is geared towards insuring against technical failure. In the case of electricity supply, this has been manifest in a tendency to over-build and to aim at high (and costly) reliability levels. In the absence of important disciplines and rewards that commonly apply to private firms, the incentive for efficient management of public enterprises is reduced.

Other factors have also reduced the incentives for efficient management. Perhaps the most important is the limited competition faced by many public enterprises. In the case of electricity and gas utilities, legislative barriers preclude direct competition from alternative suppliers. Other factors affecting management incentives linked to public ownership include requirements that electricity and gas utilities fulfill a mix of commercial and non-commercial objectives, and comply with extensive intervention by governments in many aspects of day-to-day decision making. These requirements have diminished the discipline for efficient management by obscuring objectives and diffusing lines of responsibility and accountability. The absence of performance targets and monitoring systems has further weakened the incentive for efficient management. However, unlike insolvency and takeover threats, these factors can be remedied with continuing public ownership. Indeed, it is these factors which are the major targets of corporatisation.

Within the constraints imposed by ongoing government ownership, corporatisation seeks to establish a structure of incentives that approximates those that exist for private sector managers and, by removing factors which have both advantaged and disadvantaged public utilities compared with their private sector counterparts, provide public enterprises with a more commercial focus. The New South Wales Government, which plans to corporatise ECNSW by October of this year, stated:

> ***Corporatisation is a recognition of the need to remove externally imposed efficiency restraints on the ECNSW if it is to operate effectively ...***

The problems associated with poor administration of public electricity and gas utilities and the scope for addressing these problems through corporatisation are discussed in subsequent sections of this chapter. They relate to:

- the appropriate relationship between governments and their electricity and gas utilities (Section 5.2);
- competitive neutrality, both between electricity and gas utilities, and also between utilities and other industries in the economy (Section 5.3); and
- complementary initiatives (Section 5.4).

The Commission's proposals are summarised in Section 5.5.

5.2 Relationship with government

Most major publicly owned electricity and gas utilities in Australia are statutory authorities. Statutory authorities are generally viewed as independent government bodies, created by an act of parliament to administer and discharge activities prescribed in legislation. In the case of electricity and gas utilities, the prescribed activities relate to all or part of electricity or gas production and supply within a specified region. In practice, public electricity and gas utilities have now little autonomy from government. Extensive control has effectively resided with, and been exercised by, governments.

At the same time, governments have avoided the accountability requirements which they would face if the activities were undertaken by Departments of State.

The control of utilities by governments has arisen in a number of ways. In some states, the enabling legislation gives the relevant Minister wide-ranging powers of direction. For example, Northern Territory legislation allows the Minister to direct PAWA in any way he or she thinks fit. Ministerial powers of direction are complemented in some states by legislation specifically requiring statutory bodies to obtain the consent of the relevant Minister before taking certain actions. This can cover issues such as staffing, as well as more significant matters such as new investment proposals.

In some states, it appears that government control exists as a matter of practice, even to the extent of overriding legislative provisions. For example, although the legislation specifically empowers QEC to set tariffs, in practice they are subject to approval by the Queensland Government.

The extensive involvement of governments in the management of public utilities has been subject to considerable criticism (eg the New South Wales Steering Committee on Government Trading Enterprises 1988). On the other hand, as governments represent the shareholders of electricity and gas utilities (ie the community at large), they obviously have some responsibilities. Thus, a central issue is: what are the appropriate roles and responsibilities for government in the management of authorities? This matter is discussed below in relation to:

role and objectives;

operational controls; and

performance monitoring.

Role and objectives

The role and objectives that governments have required their public electricity and gas utilities to fulfill have contributed to poor performance. This outcome mainly reflects requirements imposed by governments that utilities engage in non-commercial activities and that they perform multiple functions (eg undertake both supply and regulatory functions). Unclear and poorly specified objectives have also contributed to inefficiencies.

Non-commercial objectives

At present, all public electricity and gas utilities are required to perform certain noncommercial functions. These functions, commonly referred to as community service obligations (CSOs), usually relate to governments' social or development objectives.

The most prevalent CSOs concern pricing. With the exception of electricity supply in New South Wales, all governments require that their electricity and gas utilities charge a uniform retail price across the state/territory for all users within each tariff class.[1] While a private firm may for administrative simplicity not finely distinguish between prices charged to users in different locations, most make some allowance for the additional cost of supplying users in more distant locations. Requirements to charge residential users a more favourable price at the expense of industrial and commercial customers also apply to most public electricity and gas utilities.

Other CSOs influence the manner in which utilities' output is produced. For example, some electricity authorities' costs have been inflated because of government requirements to source coal from particular locations and/or to maintain operations at some older power stations. For example, the Queensland Government stated:

> ... in the past some older power stations have been kept in service to protect employment in the associated coal mines.

Other CSOs that electricity and gas utilities have been required to undertake include pensioner rebates, rural connection subsidies and, in some cases, obligations to meet any request for connection. CSOs currently fulfilled by major public electricity and gas utilities are summarised in Table 5.1 and detailed in Appendix 3.

Table 5.1: **Major CSOs fulfilled by public utilities**

	Type of utility	
CSO	*Electricity*	*Gas*
Uniform pricing within customer classes	All	TPA, GFCV, SECWA
Concessions to domestic users	All	-
Pensioner rebates [a]	All	GFCV, Sagasco
Low income household concessions	All	GFCV
Subsidies to large users	NSW, ESI, ETSA, QEC, SECWA	-
Emergency payments	NSW, ESI, ETSA	Sagasco
Remote area connection subsidy	NSW, ESI, QEC, HECT, SECWA	-
Remote area supply	NSW, ESI, ETSA, SECWA, HECT, PAWA	GFCV (tempered LPG)

[a] A private utility - AGL is also required to offer pensioner rebates.

1 SAGASCO Holdings is predominantly a government owned, but incorporated and listed company. Its fully owned subsidiary gas utility - Sagasco - differentiates tariffs according to location.

Source: Information supplied by participants.

In some instances, it appears that utilities have discharged CSOs of their own volition. For example, the SECV stated that:

> Some of the [CSOs] would be decisions made by the Commission itself, without having any legislative direction or ministerial direction.

Undergrounding of power lines in some heritage and tourist areas was cited as one example of this practice. These ‘voluntary’ CSOs are sometimes based on utilities' perceptions of government policy.

Many of the adverse effects associated with CSOs arise because, with a few exceptions (eg pensioner concessions for electricity and gas in Victoria and for electricity in South Australia), CSOs are not funded by governments. As shown in Appendix 3, this imposes substantial additional costs on utilities which, in turn, have to be recouped from users. For example, the SECV estimates that, in 1987-88, concessional tariffs for residential users required that an additional $177 million be charged to other consumers. Pensioner rebates in New South Wales in 1989-90 were estimated to be around $21 million. Neither estimate allows for administrative costs or for a return on capital required to discharge CSOs.

When CSOs are funded by utilities, some users have to pay more than they should to compensate for the subsidised prices paid by other users - or the costs of CSOs are reflected in reduced returns achieved by utilities and, ultimately, by the community at large. In either case, they result in income transfers between different groups in the community. If funded internally, price relativities are distorted. This, in turn, influences patterns of production and consumption and, perhaps more importantly, utilities' investment decisions. To the extent that CSOs cause utilities to engage in inefficient operational practices (eg not acquiring coal from the least cost source), further inefficiencies result.

CSOs can also adversely affect costs if restrictions on competition have to be imposed in order to facilitate internal funding. Restrictions may be necessary to permit some users to be over-charged to compensate for revenue shortfalls on sales to subsidised users. If there were no restrictions on entry, new suppliers could capture higher priced markets. This would erode the capacity for utilities to fund CSOs internally.

Given the nature of the industries and the existing market position of public electricity and gas utilities, the exact effect the removal of legislative barriers to entry would have on the degree of competition is unknown. Nonetheless, even a threat of competition would increase the incentive for utilities to contain costs.

The manner in which CSOs are currently prescribed and undertaken conflicts with public accountability and transparency objectives. Governments can determine CSOs and direct their delivery without parliamentary approval, or even knowledge of the relevant costs and benefits. This contrasts starkly with the accountability required for

appropriated funds. The involvement of governments in the affairs of their authorities - in a manner which is not ordinarily accountable - is an issue on which some State Royal Commissions are currently receiving evidence.

Finally, the existence of uncosted CSOs clouds the measurement of a utility's efficiency. In these circumstances, they can be used to disguise inefficiency. For example, the Report of the Economic and Budget Review Committee of the Victorian Parliament (1990, p. 194) stated in regard to the GFCV that:

> In comparing its performance with AGL the corporation used as an excuse for its poor performance its need to provide community service obligations.

Multiple functions

In addition to being responsible for supply, many public utilities are required to undertake regulatory functions. This includes responsibility for product standards and licensing of electrical workers and contractors. QEC, for instance, has responsibility for advising the Minister in regard to the issue of licences to generate, transmit and distribute electricity, the regulation of electricity use to ensure safety, and inspection of installations. In effect, this means that the industry regulates itself - it is both a player and umpire. This creates the potential for conflicts of interest to arise.

One public utility - SECWA - has sole responsibility for electricity supply and gas transmission and generation in Western Australia. While this arrangement may result in some economies (eg in information systems and meter reading - although in these instances co-operative actions might lead to similar savings), it can result in some conflict in objectives. For example, the quantity and/or price of gas used for electricity supply could result in the return to gas operations being less than optimal. It also reduces the scope for competition between electricity and gas. Until 1988, SECWA was also the regulatory authority for gas and electricity in the State.

Unclear objectives

Loosely specified and sometimes conflicting goals can result in efficiency being compromised and/or managers implementing policies which are inconsistent with government's intended policy direction. Poorly stated objectives may also provide management with an excuse for unsatisfactory performance.

QEC's current objectives provide one example of imprecise and ambiguous objectives. Under the Electricity Act (s. 64), QEC is required, amongst other things, to ‘ensure that prices are fair and reasonable’.

Clearly, what QEC might define as `fair and reasonable could differ appreciably from the level and structure of prices which the Government considers would conform with this requirement.

In the Commission's view, the problems caused by multiple, unclear and sometimes conflicting objectives could be largely avoided if, consistent with the objectives of private enterprises, public utilities' objectives relate solely to commercial performance.

This would involve a clear and unambiguous statement requiring that utilities supply electricity or gas (but not both) in the most economically efficient manner. Provided there is a mechanism to prevent market power being exploited, this implies that they be managed so as to maximise the return on capital employed. It would absolve utilities from undertaking regulatory functions and lessen the potential for conflicts of interest. It also implies that electricity supply and transmission, and distribution of gas, would not be undertaken by the one authority as is currently the case in Western Australia. The implications that commercial objectives have for utilities' role in energy conservation are discussed in Chapter 10.

If public electricity and gas utilities are provided with a clear commercial focus it would be inconsistent for them to continue to undertake CSOs in the current manner.

Thus, the question arises as to how CSOs should be handled.

The objectives of CSOs, their effects and alternative funding mechanisms are examined in Appendix 5. That analysis suggests that the objectives some CSOs are intended to serve cannot be justified from an economic viewpoint. For example, the Commission considers that concessional pricing provided to some large users to promote state development is not consistent with state or national economic interests. While benefiting recipients, other users are effectively taxed in order to compensate for the shortfall in revenue. In these circumstances, it is quite possible that there is a net decrease in aggregate output.

There seems no reason why some CSOs - such as undergrounding of power lines for aesthetic reasons and contributions made by some electricity utilities to the cost of road lighting - should not be wholly, or at least partly, financed on a user-pays basis. This would avoid both efficiency and equity problems caused by the current internal funding arrangements.

Major CSOs fulfilled by electricity and gas utilities - such as uniform pricing, concessions to residential users, connection subsidies and pensioner rebates - mainly relate to social objectives. In broad terms, they seek to contain prices of services (ie electricity and gas) to residential users and pensioners, and to ensure that users in outlying areas are not disadvantaged by their choice of location. However, on both equity and efficiency grounds, the Commission does not consider that it is appropriate to pursue social objectives by subsidising purchases of electricity and gas.

The major inequities are that relatively high-volume electricity and gas users benefit to a greater extent than do low-volume consumers (eg households that use alternative energy forms, such as wood or solar energy for heating and hot water).

Moreover, the size of the benefit bears no relation to the actual 'need' of the recipient. Unless funded directly by government, economic inefficiencies result from the inappropriate price signals received by groups benefiting from CSOs and also those that are 'taxed' to fund electricity and gas subsidies. These result in inefficient patterns of electricity and gas usage and, to the extent that demand for energy is distorted, can lead to inappropriate levels of investment by electricity and gas utilities.

If governments wish to assist disadvantaged groups and/or rural residents, it would be more efficient and more equitable to provide assistance by ***means*** *of social welfare programs or, in the case of rural users, through the taxation system (eg zone rebates) rather than by subsidising the consumption of electricity and gas.*

If governments insist that utilities continue to undertake CSOs, it would be more efficient if they were financed by direct government funding or by a uniform levy on users. Both approaches would promote transparency. To the extent that the CSO is considered beneficial to the community at large, direct government funding is likely to spread the cost more evenly than would a levy on energy users. As explained in Appendix 5, both of these approaches would avoid the distortionary effects which result if CSOs are financed by cross-subsidies between electricity or gas users.

Another option is for government to reduce the utility's dividend requirement by the cost to the utility of its providing CSOs. The Electricity Council of New South Wales said this option may be applied to electricity councils in New South Wales. However, the disadvantage is that the cost of performing CSOs may not be readily visible either in utilities' or government budgets. If not separately identified in government budgets, CSOs would not be subject to regular review.

According to the Western Australian Government, the requirement that SEC WA internally fund the majority of its CSOs reflects a concern that efficiency losses may be greater under direct budget funding. This was said to reflect the narrow tax base available for collecting State revenue. It stated that:

In such circumstances increases in taxes and other revenues to fund the CSOs may have a more distortionary impact on prices and lead to greater efficiency losses than if SECWA were to fund the CSOs.

The possibility that some revenue raising alternatives available to states would create greater distortions than does internal funding by way of cross-subsidisation cannot be denied. However, states also have access to alternatives (eg petrol and certain other commodity taxes) which would spread the burden of CSO funding more widely across the community than does a 'tax' on a sub-set of electricity or gas consumers. Indeed, funding electricity CSOs by means of a levy on all electricity users would offer significant advantages over the current funding arrangements. Account also needs to be taken of any costs (in terms of reduced pressures to minimise costs) stemming from the need to maintain legislative barriers to limit competition and sustain cross-subsidies.

Furthermore, the lack of transparency and accountability inherent in the present arrangement can result in CSOs continuing without periodic evaluation of their worth (eg in annual budgetary reviews). Currently, utilities themselves have little information on the cost of providing the major CSOs. The costs associated with cross-subsidies would be avoided by direct funding. Thus, while there could be circumstances where the choice of revenue-raising mechanism could result in direct funding of CSOs being less efficient than cross-subsidisation, the Commission considers that states have the capacity to ensure that this outcome does not eventuate.

The Commission considers that, if CSOs are imposed by governments on utilities, they should be funded by direct payments from government. Each CSO should be separately identified with the tasks and the expected costs (including utilities' administration and, where applicable, capital costs) clearly identified and contracted between utilities and governments. This would help formalise relations between governments and authorities and, importantly, permit adequate accountability.

Operational controls

Governments have traditionally exercised extensive control over the activities of their electricity and gas utilities. This has included control over major investment and borrowing decisions as well as control over relatively minor matters. QEC, for example, must submit annually for the Minister's approval a full list of staff considered necessary to carry out its functions.

At the draft report hearings, the SECV said that all contracts over $1 million have to be submitted for ministerial approval, as do certain property transactions. With regard to the property transactions, the SECV commented:

> ... and in that area there have been a series of interventions to propose that the SECV adopt a non-commercial approach to decision-making ...

High levels of government intervention, particularly these which relate to day-to-day operations, impair efficiency, mainly by obscuring accountability and responsibility. For example, the New South Wales Steering Committee on Government Trading Enterprises (1988, p. 14) stated:

> Externally-imposed controls stifle managerial creativity and innovation, and dilute and diffuse responsibility between managers and the governments agencies which set the controls, with the frequent result that nobody is called into account.

In its submission to this inquiry, the New South Wales Government stated that:

> A major cornerstone of corporatisation is that "close management objectives will not be successful in generating sound economic performance unless managers are given the authority to make key decisions required to achieve efficient economic outcomes".

Similarly, in its Green Paper on Government Owned Enterprises (1990, p.18), the Queensland Government commented:

> **... day to day Ministerial controls and specific regulation of GOES should be removed to the maximum extent possible.**

The Commission considers that efficiency would be promoted if the commercial focus which is at the core of administrative reform applies equally to the representatives of the owners (governments) as it does to utility managers.

Government's primary role in relation to public energy utilities should be to establish goals and to monitor performance. The responsibility for achieving the established goals should be vested in a board of directors and in managers appointed by the board. There should be no requirement or expectation that the board of directors would seek ministerial approval other than for strategic actions outside the board's prescribed responsibility.

The Board would be accountable to the parliament through the relevant Minister and the utility subject to audit by the relevant Auditor-General. Board members, who would be appointed by the government, would most appropriately be selected on the basis of their expertise in relevant commercial disciplines, and not because they represent particular interest groups within the community (eg users, trade unions or environmental groups). If government requires a forum to advise on community views, it could form its own body with representation from various community groups as, for example, South Australia did in establishing the Energy Forum in 1987.

Portfolio ministers of most electricity and gas authorities currently have the power to give directions to utilities. While there may be a case for governments to issue directions to their authorities, the Commission considers that such powers should, in practice, be restricted and essentially relate to broad policy directions.

Under corporatisation, adequate transparency and accountability would not be achieved unless all directions issued by governments were in writing and required to be tabled in parliament and incorporated in utilities' annual reports.

The latter requirement presently applies to some authorities (eg SECWA), although implicit directives may also exist.

If these procedures were implemented, governments' traditional role in influencing new investment and tariff policy would be largely removed. Concerns that governments may have about utilities implementing unwarranted price increases could be addressed by other means - such as through scrutiny by the Trade Practices Commission (see Section 5.3 below).

Monitoring performance

Providing clear objectives and greater autonomy for management will only be effective in improving efficiency if accompanied by the introduction of monitoring procedures to assess managers' performance and by an appropriate system of rewards and penalties.

Performance monitoring needs to be both rigorous and transparent and, if relevant, relate to any CSO-related activities imposed by governments, as well as to commercial goals. The Commission considers it should involve the setting of a range of financial and non-financial targets, and comprehensive reporting in utilities' annual reports of the targets themselves and the performance of utilities against the targets. If a common set of targets and measurement conventions were adopted for similar utilities, comparisons between utilities would be possible.

In-principle acceptance of the value of national performance monitoring for government trading enterprises was reached at the Special Premiers' Conference in October 1990. A report on how this can be best advanced is being prepared for the next such Conference.

Where public enterprises are engaged in the production of marketable goods - such as electricity and gas - it is appropriate that their performance be assessed against criteria similar to those used in evaluating comparable private concerns. A requirement to meet a specified rate of return on capital employed is the financial target most comparable with commercial practices.

The rate of return target has to be set at an appropriate level as it plays a crucial role in determining new investment. The higher the rate of return (or the hurdle rate) employed in the evaluation of investment proposals, the more onerous it is for projects to show a positive financial gain. The rate of return also affects the evaluation of alternative investments contemplated by public utilities, and decisions as to whether work is more efficiently undertaken ‘in house’ or contracted out.

If the rate of return employed by a public utility is low relative to that employed by comparable private organisations then:

- some projects which a private utility would not invest in will be undertaken by the public utility (ie capital will be directed away from other projects offering a higher return to the community);
- the probability of the public utility proceeding with capital intensive projects will be increased. This is due to the inverse relationship between the capital intensity of a project and the required rate of return. For example, if alternative investments in coal-fired and gas-fired power stations are evaluated, the appraisal will be (all other things being equal) more favourable to the relatively high capital cost coal-fired plant the lower is the rate of return;
- the likelihood that work will be performed in-house is increased; and

- prices offered by utilities for competing outputs (eg electricity produced from cogeneration plants) will be relatively low.

The opposite outcomes will result if the rate of return used by public utilities is high compared with that employed by similar commercial organisations.

A number of governments are considering introducing rate of return targets for their equity in electricity and gas utilities. For some years, the SECV and the GFCV were the only utilities to which such a target applied. However, rate of return targets have recently been incorporated into performance agreements entered into by New South Wales electricity councils and are also included in SECWA's corporate plan. Following the enactment of the State Authorities Financial Management Act 1990, a rate of return target also applies to HECT.

The information available on the rates of return employed by public electricity and gas utilities in evaluating non-discretionary projects suggests considerable variation between authorities. However, it is commonly agreed that the target rates for public utilities are low relative to equivalent rates in the private sector. The SECV, for example, stated that it aimed for a real rate of return of around 6 per cent. In contrast, CRA told the Commission that the newly formed UK generating companies and Electricorp - the corporatised body responsible for electricity generation in New Zealand - use after-tax rates of 8 and 7.5 per cent, respectively. CRA said that private investors in utilities in the United States of America seek similar returns.

At the draft report hearings, some participants contended that rates of 8 per cent and above are inappropriate. For example, the Australian Chamber of Manufacturers stated:

> We contend that a target real rate of return on assets of 4% on the written down current costs of assets is unrealistically high for a public utility.

Similarly, the ESAA claimed that 8 per cent is too high. It stated that the average pretax return achieved in the Australian corporate sector between 1976-77 and 1985-86 was 5.9 per cent.

There is considerable debate about alternative approaches to evaluating the opportunity cost of capital for a public enterprise, and whether or not it should vary between different activities of government.[2] While this debate may not be easily resolved, there is a strong case on efficiency grounds for ensuring that public electricity and gas utilities do not employ artificially low rates. The benchmark of 8 per cent (real, before tax) employed in the quantitative studies undertaken for this report (see Chapter 4) and other recent Commission studies of government business enterprises (see IC 1990), was based on the real rate of return on a riskless asset (long term government bonds),

[2] For a more detailed discussion of this issue, see IAC (1989, Vol. 3, pp.115-136), Commonwealth Department of the Treasury (1990) and Commonwealth Department of Finance (1987).

adjusted for a small margin of risk. It is not necessarily the rate which the Commission believes is appropriate for public energy utilities. Further study is required to determine what the appropriate rate should be.

To be effective, rate of return targets have to be determined on an adequate commercial accounting/economic basis and take account of any factors which advantage or disadvantage public utilities compared to the operations of a private firm engaged in the same activity. Provision also has to be made for the possibility that electricity and gas utilities may be able to meet such targets simply by using market power to increase output prices.

These matters are discussed in more detail in the following section.

A range of non-financial targets are also appropriate. These can assist monitoring of utilities' performance in discharging CSOs and also help to ensure that financial targets are not met by reducing the quality of outputs. They can also promote efficiency by permitting comparisons of utilities' operations (so-called ‘yardstick’ competition). Non-financial targets can relate to technical aspects (eg the availability of generating capacity and system reliability), to operating efficiency (eg staff-customer ratios) and, in the case of distribution authorities, to the incidence of service faults and to response times.

Technical indicators of performance have been included in performance agreements between the New South Wales Government and electricity distribution authorities. They cover all aspects of operations: customer and marketing; human resources; business management; the electricity supply system; planning and development; and, environment and community.

The application to electricity and gas utilities of public sector employment conditions embodying pay scales for managers that are low by commercial standards and which make dismissal unlikely in practice has restricted both rewards for efficient management and penalties for poor performance. Recent initiatives in some states have gone some way to overcoming this problem. In New South Wales, for example, senior ECNSW executives (along with senior executives in a number of other areas of Government) are employed on a contract basis. While this provides greater rewards than in the past (in the form of considerably higher remuneration packages), it also allows for replacement should performance over the contract period be inadequate.

An appropriate system of rewards and penalties is an essential complement to performance monitoring measures.

5.3 Competitive neutrality

Compared to private sector organisations, public electricity and gas utilities have enjoyed some advantages and suffered certain disadvantages in both input and product markets. If a more commercial orientation is to be achieved, it is essential that these advantages and disadvantages be removed, or at least eased, to enable public electricity and gas utilities to compete between themselves and with the private sector in a more neutral environment. Major elements of change would involve:

- legislative barriers to entry;
- liability for government taxes and charges;
- accounting conventions;
- dividend requirements;
- borrowings;
- general public sector policies; and
- incorporation under the Companies Code.

Legislative barriers to entry

At present, legislative barriers to entry preclude direct competition with public electricity and gas utilities (see Appendix 3 for details). Significant competition exists between electricity and gas in some market segments. However, in other market segments, the absence of competition reduces the pressures on utilities to contain costs and operate efficiently.

In the ESI, electricity can only be generated for public sale with the approval of the relevant Minister or electricity authority. There are generally no explicit regulations that limit the generation of electricity for private use, although some state legislation could provide electricity authorities with such power. For example, the Electricity Act 1976 (s. 36) gives QEC the power to:

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

In New South Wales, electricity councils cannot generate electricity without the approval of ECNSW. Similar restrictions apply to regional boards in Queensland and municipal electricity undertakings in Victoria.

Other barriers to entry include the provision of exclusive franchises for electricity and gas distribution. These effectively provide some electricity and gas distributors with regional monopolies. On the other hand, some utilities (eg electricity councils in New South Wales) have been obliged to meet requests for new connections in their region, often at concessional rates.

Some utilities are insulated from competition by exclusive purchasing rights (eg PASA is the only authorised buyer of gas from producers for use in South Australia). In some states (see Appendix 3 for details), the right to own and/or operate gas transmission pipelines is vested in the one body (eg the GFVC is the only body authorised to construct and/or operate gas pipelines in Victoria). BHP Petroleum stated that this latter factor is largely responsible for the shortfalls in gas being faced by South Australia and New South Wales:

> The failure to serve these potential markets has in large part been caused by the awarding of an exclusive franchise to serve the State of Victoria to a state based agency. Buying and transmitting gas to other states is outside the GFCV's current activities other than sales to Albury.

The desirability of increasing the exposure of the industries to market forces was stressed by a number of participants. For example, the New South Wales Government said:

> ... the greatest efficiency improvement in the generation, transmission and distribution of electricity and gas will be gained by the introduction of reforms which lead towards free market arrangements.

Regulatory barriers to entry restrict competition and provide electricity and gas utilities with advantages which are not available to most industries. The removal of such restraints are essential if the goals of corporatisation are to be achieved A necessary complement is the removal of any requirement to extend supply to new users at concessional rates.

Liability for government taxes and charges

Although there have been a number of changes made or foreshadowed in recent years, most public electricity and gas utilities remain exempt from a range of Commonwealth, State and Local Government taxes and charges.

Most state authorities are exempt from Commonwealth income and other taxes. Some pay an equivalent amount to state treasuries, although the ‘levy’ is generally not determined on the same basis as would be the tax if it applied. Liability for state and local government taxes and charges (eg payroll tax, land tax, stamp duty etc) varies between utilities (see Table 5.2).

Table 5.2: **Public utilities' liability for major taxes and charges**

Tax/Charge	*Liability*
Commonwealth	
- Income	All exempt, apart from Sagasco[a]
- Sales tax	All exempt, apart from Sagasco
- Excise	All liable, apart from GFCV and ACTEW
State/Territory	
- Payroll	All liable
- Local Government	All liable except PAWA, ACTEW and ECNSW (part liability)

[a] Unless exempted by the State Treasurer, HECT must make payments equivalent to Commonwealth income tax

Source: Based on information supplied by participants

Exemptions from government taxes and charges distort utilities' costs (both in absolute terms and in terms of the relative cost of inputs) and, as a result, adversely affect pricing and productive efficiency. It also results in a misallocation of resources between utilities and other sectors of the economy, including private utilities which are liable for all government charges and which compete with public utilities.

It is appropriate for public utilities to pay all state taxes and charges commensurate with those which would apply to a private utility and, in lieu of paying Commonwealth taxes and charges to the Commonwealth Government, an equivalent amount to state treasuries.

If implemented, this approach would also help overcome the differential treatment accorded electricity and gas utilities in some states. It would, for example, mean that coal used by electricity authorities, including coal sourced from the authorities' own mines or state-owned mines, would be subject to the same royalty requirements as coal produced for other uses where this does not currently apply. It would also mean that requirements for franchise fees and easement rights would be uniform for both electricity and gas utilities.

Accounting conventions

The accounting practices adopted by public electricity and gas utilities are in many cases out-dated and do not convey meaningful information to either the utility or the community. Perhaps the major problem is asset valuation. With some exceptions (eg SECV, GFCV and ETSA), public electricity and gas utilities value fixed assets at historical cost. When prices are increasing this results in assets being undervalued, depreciation charges being understated and profits (losses) being overstated (understated). Consequently, rates of return based on such asset values are exaggerated.

The current value of assets held by publicly listed private companies can be determined by reference to the share market. However, no such market exists for government owned enterprises. In addition, there is no easily identifiable price for some specialised assets owned by public bodies (eg pipelines).

If the activity of a utility is to be ongoing it is appropriate to base the value of specialised fixed assets on current replacement cost. Assets values for land and buildings can, in most instances, be valued by reference to market prices. Current values could be shown in notes to published financial statements.

Prior to the 1980s, many government bodies employed a cash basis for accounting. Since then, far greater use has been made of accrual accounting. However, one major public electricity utility - QEC - continues to compile accounts on a cash basis. This does not provide a useful guide to performance.

Further problems are created by the substantial differences in the accounting practices employed. In the case of electricity, the Commission was told that the accounting information published in a common format for each electricity authority in the Annual Report of the national body (ESAA) was not inaccurate, but that it was misleading and unsuitable for comparative analysis.

There is a clear need for all public electricity and gas utilities to adopt more commercial accounting practices. To facilitate monitoring and performance assessment, published information needs to be on a comparable basis and published in greater detail than is the case at present. There is also a need to account for all funds, including all loans and grants from government treasuries.

Dividend requirements

Dividend requirements vary markedly. In Victoria, there is legislation requiring GFCV, SECV and some other state instrumentalities to pay a Public Authority Dividend. The actual payment is determined by the Treasurer in consultation with the relevant Minister, but cannot exceed an amount equal to 5 per cent of public equity. In Tasmania, the Government has enacted similar legislation, although HECT has yet to make a payment under it. In other states/territories, there is no firm policy. In some, public utilities pay an amount based on sales revenue (eg ETSA pays 5 per cent of sales revenue to the South Australian Government and SECWA pays 3 per cent of sales revenue to the Western Australian Government). These payments may not bear any relation to profitability and thus resemble a tax on utilities rather than a formal dividend. A number of public energy utilities (eg QEC, TPA and SMHEA) pay no contributions to government. Dividends and other major contributions to governments for 1989-90 are shown in Appendix 3.

Just as most publicly listed companies pay dividends to their shareholders, it is also appropriate for public electricity and gas utilities to return a dividend to government.

Like private firms, public electricity and gas utilities should have some flexibility to vary dividend payments according to financial circumstances and operating requirements. However, just as governments should set rate of return targets for public electricity and gas utilities, it would also be appropriate for them to set dividend targets. To allow some. flexibility, the targets could apply to (say) 5 year periods. In practice, it would be difficult to determine targets but, in principle, they should approximate the average dividend rate paid by similar private companies.

Borrowings

Borrowings of most public electricity and gas utilities are significantly influenced by governments. This includes:

- constraints resulting from state borrowing limits imposed by the Australian Loan Council (ALC);
- requirements to make borrowings through state treasuries or government finance corporations;
- the provision of non-repayable grants;
- the provision of funds at concessional interest rates; and
- government loan guarantees, frequently available at no cost to utilities.

These factors apply to public utilities to varying extents. For example. while all are affected, or potentially affected, by ALC borrowing limits, only some are advantaged by having their loans guaranteed at no cost. ETSA, for instance, pays a fee of ½ of a per cent on borrowings which, in 1989-90, amounted to $3.1 million. Others (eg GFCV and PAWA) currently pay nothing for loan guarantees.

Some participants (eg Sagasco) considered they should be exempt from ALC limits on borrowings. Others registered concern about their effects. For example, the Queensland Government stated that:

> ... the level of borrowings by a State for economic infrastructure should not be a matter of concern to the Commonwealth Government and should not be subject to limits imposed by the Loan Council ... Arbitrary restrictions on borrowings through global limits may impose substantial opportunity costs on the State and the nation in terms of economic growth foregone.

The variation in conditions between utilities, coupled with the fact that some of the factors advantage utilities while other are to their disadvantage, mean that their net impact is uncertain. However, they clearly impose a different set of conditions on the borrowings of public utilities compared to private firms and, hence, affect the availability and cost of capital. This, in turn, impairs internal decision-making and affects the allocation of resources between the public and private sectors.

The question of exposure of government trading enterprises to ALC controls was discussed at the Special Premiers' Conference. The communiqué stated:

> ... the question of whether such bodies, where operating in a fully competitive environment, should continue to be subject to Loan Council contracts will be settled at the next Loan Council meeting ...

If all of the changes outlined in this chapter are applied to public electricity and gas utilities so as to give them a commercial focus, the Commission considers that constraints on public utilities' borrowings could be removed Equally, utilities should pay commercial rates for any funds or loan guarantees provided to them by governments.

General public sector policies

To some extent, all electricity and gas utilities are subject to other policies that apply to a variety of government instrumentalities, but not to private organisations. Such policies are concerned with:

- public sector employment and industrial relations;
- government purchasing preferences;
- exemption from the Trade Practices Act (TPA); and
- exemption from scrutiny by the Prices Surveillance Authority (PSA).

At the draft report hearing, the GFCV provided one example of how requirements to adhere to general public sector policies disadvantage its operations. It stated that, because its executive salaries are fixed by government at levels significantly below those in private enterprise, it experiences difficulties in retaining senior staff. GFCV noted that it has only two executives receiving a remuneration falling within the executive range specified in stock exchange reporting requirements, while AGL - a private utility half the size of GFCV - has over forty.

The exemptions from the TPA and from scrutiny by the PSA potentially provide public energy utilities with a degree of flexibility unavailable to private enterprises. Extensive government oversighting of utilities operations has, at least to some degree, substituted for these exemptions. However, implementation of the measures outlined in this chapter would substantially remove government oversight and create opportunities for the use of market power. In these circumstances, there is a need to ensure that there is some oversighting of public energy utilities. In principle, the Commission sees no reason to distinguish between the regulatory oversight required for a publicly owned energy utility and that applied to a private utility. The nature of this regulation is discussed in the following chapter.

In the March 1991 Industry Statements, it was announced that the Commonwealth Government wishes to discuss with state and territory Governments ways in which present exclusions from the TPA might be brought within the scope of a national framework of competition policy and law.

If the other initiatives outlined above are implemented so that the public electricity and gas utilities are placed on a commercial footing, there is no reason to differentiate between a publicly and privately owned enterprise. Public electricity and gas utilities should not be constrained by general public sector policies. Equally, they should not be exempt from the TPA or scrutiny by the PSA..

Incorporation under the Companies Code

A further consideration is whether, once the initiatives outlined in this chapter are taken, utilities should be incorporated under the Companies Code. Sagasco, because of its holding company's private shareholding, is already subject to the Companies Code. GFCV, which also has a private shareholding, has its own Act which exempts it from the Code. The New South Wales Government intends to incorporate ECNSW under the Companies Code.

Although much of the scope of company legislation would not be applicable to incorporated utilities (eg takeover provisions), incorporation places on company directors a burden of responsibility to shareholders, creditors and others which is not duplicated under usual statutory authority legislation. Additionally, the application of the Companies Code would place government entities on the same footing as private utilities; would subject them to a national, uniform discipline (including monitoring by the TPC); and should enable any legislative weaknesses to be identified and remedied more readily than could occur with disparate legislation.

Companies subject to the Companies Code are generally liable for Commonwealth Government income tax. In the past, there has been some uncertainty whether this would mean that public bodies subject to the Code would also be liable. If this were the case then, provided a government body was trading profitably, funds would be diverted from state/territory governments to the Commonwealth. However, the Commission understands that incorporating a body under the Companies Code can be authorised by State/Territory Acts of Parliament. In the case of New South Wales, this would also include the new corporations in a schedule to the State-Owned Corporations Act. These actions would be sufficient to distinguish new corporations as public authorities constituted under State Acts for the purpose of the Income Tax Assessment Act and, hence, exempt them from the provisions of that Act.

The Western Australian Government's draft report submission raised the difficulty of accountability. However, under the Companies Code, shareholders appoint the company's auditor. Thus, State, Territory or Commonwealth Auditors-General could be appointed as auditors. Company boards would not be able to resist a request to appear before parliamentary committees assessing the company's performance.

At the draft report hearings, the Local Government Electricity Association of New South Wales contended that, as electricity councils were predominantly funded by local communities, they are local government, not State Government bodies. Consequently, it claimed that corporatisation - under State legislation - and subsequent incorporation under the Companies Code would be inappropriate because dividends and accountability would be to the State Government, and not to local communities.

It is not clear that local electricity distribution bodies are owned by local communities. For example, electricity councils in New South Wales are, in part, funded from the

Electricity Development Fund; the largest council (Sydney Electricity) is in the process of being corporatised under state legislation; and under performance agreements entered into with the New South Wales Government, Sydney Electricity and the three other large urban-based councils are to pay dividends to the State Government. Nonetheless, even if it were established that local electricity bodies are owned by local communities, they could still be incorporated under the Companies Code with ownership residing in local councils on behalf of local communities. In these circumstances, local councils would appoint boards and receive dividend payments, and the boards would be accountable to the councils on behalf of local communities.

The Commission considers that all public utilities should be incorporated under the Companies Code.

5.4 Complementary Initiatives

If reforms encompassing the measures outlined above were introduced for public electricity and gas utilities, it is likely that many existing practices would be modified or discontinued. Some of the more important of these concern private sector sourcing and interstate connections of electricity transmission systems. These matters are discussed briefly below.

Private sector sourcing

Requirements to meet rate of return targets and to act in a more commercial fashion would create increased incentives for public electricity and gas utilities to assess more rigorously the possibility of increasing the use of private sector resources. This could involve greater use of contract labour for refurbishments, maintenance etc, greater involvement with buy-back arrangements from co generators and other private electricity generators, and an increased role for the private sector in owning and/or operating new capacity (eg new power stations or gas pipelines).

The Urban Development Institute of Australia submitted that, while property developers are increasingly being required to fund electricity infrastructure costs associated with new developments, they are generally unable to have the design and construction work undertaken by a private contractor, even if that would reduce costs.

There would seem to be no reason why the notion of contracting out why cannot be extended to all facets of construction, including extensions to distribution networks paid for, wholly or in part, by property developers. Requirements that all such work be undertaken by electricity authorities unnecessarily restricts construction options and may well increase costs.

A number of public utilities (eg QEC and ECNSW) have already substituted contract labour for in-house resources in a wide range of applications. This has provided utilities with a more cost effective basis for handling cyclical and/or intermittent workloads (eg annual maintenance, plant refurbishments and unexpected breakdowns).

Trade unions have generally resisted attempts to increase the use of external contractors. While those barriers have been reduced in some utilities, it is apparent that there is still considerable opposition. For example, at the draft report hearing, the ESAA said that there is:

> ... very real trade union opposition which has to be overcome before utilities can eliminate featherbedding and costly internal activities which could be more economically supplied externally.

Participants indicated that greater workforce flexibility is being facilitated by award restructuring. For example, in outlining initiatives undertaken by local distribution authorities, the New South Wales Government commented:

> ... the more recent national wage decisions of industrial tribunals have required consultation between employers and employees with respect to such matters as work practices, methods, demarcation, training and award broadbanding and restructuring. These procedures have enabled employers to

negotiate significant changes increasing the flexibility of the workforce with the consequent increase in productivity and reduction in labour costs.

Nonetheless, there would appear to be scope for greater use of external contractors. In this regard, the Chairman of the SECV recently commented:

> There are a large number of in-house functions in all public utilities which based on experience and tenders indicates can be done more cheaply and effectively by the private sector. The move is underway but is only moving slowly at this stage because, frankly speaking, there is about as much management resistance as union resistance.

In contrast to contracting out, private sector involvement in buy-back arrangements and in adding to new capacity has been relatively minor to date. According to some participants, the relatively low level of private sector involvement reflects, in part, impediments which need to be overcome.

Buy-back arrangements

Private firms often find it advantageous to supply all or a proportion of their own electricity, either by using waste products as a fuel or by cogeneration to use fuel more efficiently. Some also need to install an emergency supply in case of a power failure. If there is generating capacity surplus to their needs, firms may elect to sell some output to electricity authorities. Indeed, in some instances the return obtained from external sales determines the viability of installing private generating facilities in the first place.

For utilities, buy-back arrangements can be structured to offer increased system flexibility to meet unexpected peaks or to cope with unplanned outages. They may also allow for deferral of new investment.

Despite these benefits, the number of buy-back arrangements in operation is limited. There are several possible reasons for this. Some participants claimed that, first, it is difficult to ascertain authorities' buy-back rates and, second, that the rates are ‘too low’. One participant, Electricity Week, commented that:

> ... utility managers see cogeneration as an unwanted competitor, rather than as an important contributor to the efficiency in the industry.

Low rates of return employed by authorities in evaluating alternative generating options, and more favourable tax treatment and other advantages accruing to public utilities but not to private generating plants, were also said to discourage private generation to some extent.

Some participants referred to the situation in the United States (see Appendix 9) whereby utilities are required by legislation to purchase power from co generators and certain small production facilities (eg those that utilise renewable energy). Subsequent legislation in the United States has specified that the price paid has to reflect the costs that the utility avoids (‘avoided cost’) by purchasing from an independent supplier.

Some of the present barriers inhibiting private generation in Australia would be removed if authorities were corporatised along the lines suggested above. For example, corporatisation would require that utilities have realistic rate of return targets and no longer enjoy some advantages (eg tax exemptions) which are not available to private generators. The emphasis on financial returns and efficiency would also mean that public electricity utilities would be more likely to view themselves as ‘suppliers’, and not just ‘producers’ of electricity. In these circumstances, a more objective appraisal of the merits of entering into buy-back arrangements is likely.

The Commission is not in favour of forcing utilities to enter into buy-back arrangements or to mandate prices paid for privately generated power. To do so would impose constraints on utilities of a type which do not apply to private sector organisations and which would be contrary to the general thrust of corporatisation.

If utilities are free to negotiate with private suppliers, prices paid for private supply would generally lie between utilities' avoided costs and private suppliers' costs, less an allowance for standby capacity, reliability, transmission costs and the like. The actual outcome will be influenced by many factors, including the existing capacity of the utility, the number of sellers and the quantity of electricity which private suppliers wish to sell at any point in time. If utilities have an on-going need for additional supply from private generators, it may be in their own commercial interest if, as far as possible, they publish a schedule of rates. On other occasions, it may be appropriate for utilities to invite tenders for small increments of supply. However, while co generators continue to face a single buyer, the use of cogeneration may not be optimised. The structural reforms canvassed in Chapter 7 are, therefore, relevant to this issue.

New capacity

The proposed reforms to public utilities should result in a more rigorous and balanced appraisal of new investments, including the possibility of their being built, owned and operated by the private sector, as has recently been decided for the next base-load plant in Western Australia. The SECV has stated that the partially completed Loy Yang B power station ought to be sold and privately operated. Other utilities (eg ECNSW) have held discussions with private companies that are interested in building and operating new base-load power stations for them. However, concerns have been expressed whether public utilities, which have traditionally generated their own power requirements, are in a position to make unbiased assessments of tenders for new capacity, one of which is likely to be from the utility itself.

In this inquiry, CRA expressed dissatisfaction over the procedures for evaluating options for a new power station in Western Australia. It claimed that there was ‘a very high degree of political involvement in the decision making process’, that the tendering process did not treat coal and gas options in the same manner, and that SECWA's own bid had not been made public or verified by a. third party.

If public utilities are corporatised, there would be increased pressure on them to evaluate tenders objectively. However, attitudes may not change overnight. Moreover, some potential bidders may not participate because they perceive that tender arrangements have not worked satisfactorily in the past.

Given these factors, and the significance of new investments in power stations, pipelines and the like, there is a case for ensuring that selection processes are, and are seen to be, impartial and as transparent as possible.

The Commission expects that once the changes proposed in this chapter are put in place, it would be in public utilities own interests to call tenders for all major new investments. However, as an interim measure, the Commission proposes that utilities be required to tender all such investments and that the evaluation of tenders be scrutinised by a neutral body.

Electricity Interconnections[3]

In the past, public electricity utilities have frequently been reluctant to pursue possibilities for sourcing power from other states. As stated by the New South Wales Government:

> … political interests in the past have made it difficult for states to negotiate long term contract sales, despite the substantial economic benefits available.

[3] This issue is also discussed in Appendix 6.

Similarly, a recent South Australian Government Green Paper (1991) noted:

> At various times the State has pursued a goal of energy independence, at least with respect to electricity.

Consequently, each state and territory (with the exception of the ACT) has provided its own generating capacity with little regard for the possibility of acquiring electricity from adjacent systems or, alternatively, of constructing its own facilities in other states. Technical factors that once constrained interconnection options have been overcome for some years, although the geographic isolation of Western Australia and the Northern Territory means that interconnection is not currently a viable option.

For many years, the only significant interconnection in Australia was between the New South Wales and Victorian systems. That link was a consequence of the construction of transmission facilities to enable the states to take their Snowy electricity entitlements. With the completion in early 1990 of a new transmission line linking Victoria and South Australia, the three states are now interconnected, although the links are of modest capacity. Until recently, all exchanges have been on an ‘opportunity’ basis, (ie sales are arranged on a daily basis when cost differentials make it viable). However, ECNSW has now entered into a contract to supply 1000GWh per annum to the SECV.

In other countries, interconnections between adjacent electricity systems are common, even where it involves crossing national boundaries. In some cases (eg the link between Sweden and Finland) lengthy under-sea links are involved. Every EC member state except Ireland is now linked to one or more of its neighbouring countries' grids. While there is already extensive trade in electricity (eg France and Italy are substantial electricity exporters and importers, respectively), recent studies suggest that additional savings of up to ECU 55 billion - around $A90 billion - are possible between 1992 and 2010 by closer integration of EC electricity systems.

Factors such as relatively low population density and the longitudinal orientation of development along the east coast reduce the incentive to interconnect in Australia compared to Europe. Nonetheless, there would still appear to be significant benefits available from fuel savings and resource rationalisation. A 1989 study prepared for the IAC by Intelligent Energy Systems (1989) estimated benefits in the order of $180 million annually. The benefits stem from strengthening interstate linkages and constructing additional gas-fired capacity in Victoria.

At the draft report hearing, the ESAA and SECV claimed that the IES study overstated the benefits of new interconnections and that the annual benefits would more likely be in the order of $110 million. Even if this lower figure is accepted, the overall benefits are substantial - in excess of $1 billion over a ten year period.

The possibility of further interconnections is being reviewed by a number of bodies. Recently, the Victorian and Tasmanian Governments announced that they will undertake a major study to examine the establishment of an undersea power link between the two states. The announcement follows the findings of a pre-feasibility study (SECV - HECT 1991) which concluded that a Bass Strait link could yield net economic benefits of $120-570 million.

At the Special Premiers' Conference in October 1990, it was agreed that there may be additional benefits from an extension of, and/or organisational changes to, the interstate electricity network covering New South Wales, Victoria, Queensland, South Australia, Tasmania and the ACT. A working group has prepared a report on possible grid extensions and organisational options for the next Conference.

At the draft report hearings, the ESAA stated that, in view of the prospective interconnection of Queensland and Tasmania, it would be appropriate to broaden the membership of the existing Interconnection Management Committee to include QEC and HECT. The ESAA contended that this enlarged body of representatives of electricity authorities could then manage the 'national grid'. This proposal is discussed further in Chapter 7.

Two important factors which impinge on the operations of the existing interconnections and/or on future investment decisions are the operation of the Snowy Mountains Scheme and the Victorian Government's policy on the use of gas for electricity generation.

The Snowy Mountains Scheme is administered by two bodies - the Snowy Mountains Hydro-Electric Authority (SMHEA) and the Snowy Mountains Council (SMC). SMHEA is a Commonwealth Government enterprise established under the Snowy Mountains Hydro Electric Power Act 1949. SMC is an unincorporated body representing the interests of the Commonwealth, New South Wales and Victorian Governments. Recent reports (eg McKinsey 1986) and submissions to this inquiry indicate that the respective responsibilities of these two bodies are unclear. According to McKinsey, this:

> ... has created the greatest possible constraint to the development of effective, efficient, and accountable management... .

If the Scheme is to be managed efficiently, it is essential that responsibilities be clearly defined Ideally, the same corporate focus would be adopted for the Snowy as that proposed for other public electricity authorities. This would imply vesting authority for the management of the Scheme in a single body.

Two aspects of the pricing arrangements resulting from the 1958 Commonwealth/States Agreement also impair efficiency. These are, first, the requirement that all costs of operating and maintaining the scheme be recouped from electricity charges rather than from water as well as electricity and, second, the inability of the Authority to charge a rate for electricity sufficient to recover all economic costs. As a result, the prices charged for both electricity and water convey misleading information. This creates the potential for inappropriate decisions concerning day-to-day use of the scheme and, perhaps more importantly, it can lead to uneconomic investment decisions. The absence of a rate of return to the Commonwealth from large capital maintenance projects currently proposed by SMHEA should mean that necessary investment is not undertaken by the Commonwealth.

Prices must be more reflective of costs if the contribution of the Snowy Mountains Scheme to the Australian ESI is to be maximised

The Commission recognises that changes to the existing arrangements would require both inter-and-intra government negotiations. It also notes that both the institutional and pricing arrangements form part of a review of the Scheme initiated by the Prime Minister.

In parts of Australia (eg Northern Territory and South Australia), the availability of natural gas has been seen as providing an opportunity to increase the efficiency of electricity generation. Esso stated that, relative to coal, the use of natural gas has three major advantages. First, higher thermal efficiencies can be achieved with combined-cycle natural gas fired power stations; second, the capital costs of gas combined cycle power stations are about two-thirds those of black coal; and third, carbon dioxide emissions are only about 40 per cent that of a black coal plant.

However, in Victoria, past Government policy has not allowed gas to be supplied for new power stations. Following the NREC Review (1988), the policy now permits up to 500MW of new peak or intermediate load plant to be gas-fired, but prohibits the use of gas for new base-load plant. The policy presumes that government can more efficiently allocate gas resources than can market forces. The Commission has seen no evidence to support this position.

The limitation on the use of natural gas for electricity generation constrains consideration of new power station options, not only for Victoria but for a more integrated south-eastern Australian grid. The Commission considers that this restraint should be abolished.

If public electricity authorities are re-structured so that they operate at arms length from government and are required to meet rigorous commercial objectives, the effect of some factors which have impeded consideration of interstate trade in electricity (eg political concerns and the proprietary interests of authorities) would be reduced.

Submissions to this inquiry suggest that there already exists a greater willingness on the part of governments and authorities to consider all alternative power options - including sourcing electricity from interstate. Corporatisation of authorities would increase the incentives for thorough evaluation of the possibilities for reducing costs by increasing interstate trade in electricity. However, if the potential benefits available from increased interstate interconnections are to be realised, such attitudes must be translated into positive actions.

5.5 Summary of proposals

The Commission recommends that all public electricity and gas utilities be corporatised as soon as possible, preferably within 12 months. Major elements of this approach would involve:

- providing utilities with clear objectives that relate to commercial performance only;
- abolishing requirements for utilities to perform regulatory functions;
- abolishing requirements for utilities to undertake CSOs. If, however, some residual CSOs remain, they should be individually identified and costed, and directly funded by government;
- vesting management responsibility in a board of directors accountable to parliament through the relevant minister. Directors should be appointed on the basis of relevant commercial experience;
- establishing performance monitoring based on financial and non-financial targets and incorporating an appropriate set of rewards and penalties to apply to managers;
- removing legislative barriers to entry and obligations to supply new users at concessional rates;
- making utilities liable for all government charges and taxes;
- adopting uniform and commercial accounting practices, particularly in relation to asset valuation;
- requiring public utilities to pay dividends to government equivalent to those that would be paid by similar private companies;
- removing constraints and advantages associated with utilities' borrowings; and
- removing other public sector constraints (eg the need to conform with government employment policies) and advantages (eg exemption from the Trade Practices Act) that apply to public utilities, but not to private organisations.

Once these initiatives are taken, electricity and gas utilities should be made subject to the Companies Code.

The Commission does not consider that the quantity or price of electricity purchased from co generators or other small private suppliers should be constrained by regulation. The Commission recommends that, as an interim measure, there should be a requirement for all large items of new capacity to be subject to tender, and that assessment procedures be scrutinised by a neutral body.

The Snowy Mountains Scheme is not performing as efficiently as it could. Responsibility for management needs to be vested in one body and pricing procedures amended.

Corporatisation would improve the performance of public electricity and gas utilities. However, they would still face only limited competition, some market disciplines that apply to private firms (eg threat of takeover) would still not apply, and the possibility of government interference in utilities' operations would remain. Consequently, further changes are required to ensure that public electricity and gas utilities operate as efficiently as possible. The nature of these changes is discussed in Chapters 7 and 8.

6 REGULATION OF PRIVATE UTILITIES

At present, almost all activity by private utilities relates to the transmission and distribution of natural gas Administrative change to these utilities involves the introduction of more efficient regulatory controls. In recent years there have been significant modifications to regulations in some states. However, further changes are required if private utilities are to function as efficiently as possible.

This chapter discusses administrative reform of private utilities. This encompasses changes intended to enhance performance by improving the effectiveness of government regulatory controls and, thus, increasing the incentive for efficient management of private utilities. Measures to actively promote more competition (eg compelling pipeline owners to carry gas for any party - so-called 'open-access') are addressed in the following chapter.

While administrative reform can apply to both private electricity and gas utilities, private utilities (with some relatively minor exceptions) are currently involved only in gas transmission and distribution.[1] Moreover, there is relatively little regulatory control over distributors of other gases (eg LPG). Consequently, this chapter focuses on the regulation of private gas utilities involved in the transmission or distribution of natural gas. The discussion initially covers regulation to control the use of market power (Section 6.1). Subsequent sections review regulation in relation to gas tariffs (Section 6.2), franchise terms and conditions (Section 6.3) and trade in natural gas (Section 6.4).

6.1 Regulation to control the use of market power

Private gas utilities in Australia have traditionally been subject to a range of regulations intended to ensure that market power is not misused. Concerns over the possible misuse of market power by natural gas distribution utilities arise because, although they face competition from electricity in most markets and from other forms of gas in some areas, they are sole suppliers of natural gas in their franchise areas. Similarly, gas transmission utilities do not face competition from alternative suppliers of transmission services. Governments in Australia (and in other countries) have therefore introduced regulations covering, inter alia, price levels and pricing practices generally, and access to the services provided by utilities.

[1] The exceptions include Northern Territory Power Pty Ltd which operates the 132kV transmission line between Darwin and Katherine and some private generators in remote locations.

In Australia, such regulation has not extended to publicly owned electricity utilities. However, as noted in the previous chapter, if public electricity utilities are corporatised as proposed by the Commission, it would be appropriate for them to be subject to similar, or the same, regulation to that applying to private gas utilities.

Recently there have been quite significant changes to the regulations governing the market conduct of private gas utilities - particularly in Queensland and New South Wales. In 1988, there were major revisions to the Queensland Petroleum Act 1923-86 and the Queensland Gas Act 1965-88. The New South Wales Gas Act 1986 was amended in 1990. In broad terms, the modifications have been introduced with similar objectives in mind. They are aimed at:

- improving the effectiveness of regulations;
- enhancing incentives for gas utilities to improve efficiency;
- reducing legislative impediments to competition; and
- reducing the administrative cost of regulation to industry.

Despite this similarity, there are significant differences in the approaches adopted to control the use of market power, in particular in relation to the mechanisms used to regulate pricing practices and the role and nature of the regulating body. These differences reflect on-going debate about appropriate regulatory mechanisms, not only for energy utilities, but for a range of other important activities in which there may be scope for the use of market power (eg telecommunications, water supply and aviation services). This debate is also relevant for the structural and ownership changes proposed in Chapters 7 and 8 of this report.

The extent of regulation

There is a continuum of options between employing detailed regulations to circumscribe industry behaviour (a 'heavy handed' approach) and relying on an oversighting agency to monitor actual market outcomes (a 'light handed' approach). Implicit in a 'light handed' approach is the threat of detailed regulation and close oversight if market power is misused.

The extent of market power available to an enterprise (or an industry) is primarily dependent on competitive pressures. If there are many independent suppliers of a good or service competing for market share, the market power of any one supplier is likely to be small. On the other hand, if there is only one or a small number of dominant suppliers of a good or a service, there is potential for the use of market power. Whether or not this potential can be realised is largely determined by the availability of substitute goods. If close substitutes exist, an enterprise may have little market power, even though it may be a sole supplier.

Market power can also be influenced by linkages which may exist between an enterprise (or industry) and its major input suppliers and with end users. For example, if an enterprise which faces many competitors in selling its output is vertically integrated so that it is able to control the terms and conditions under which the major material input used by all firms in the industry is supplied, that vertically integrated enterprise may also be able to exert market power in its product market.

At present, electricity and natural gas are each supplied by a single supplier within a region. This reflects the natural monopoly characteristics of parts of the industries and legislative provisions which give most energy utilities sole right of supply within prescribed areas. There is also a high degree of vertical intergration in electricty supply in all states. Vertical integration in natural gas supply occurs only in some states. However, both electricity and gas are exposed to some competition. Gas faces competition from electricity in virtually all energy markets which are supplied, or can potentially be supplied, by gas. On the other hand, there are some markets in which electricity has no direct competition from gas or any other energy source (eg as an energy source for street lighting and many home appliances). Consequently, electricity utilities appear to have greater scope than gas utilities to use market power, although neither has the same scope for using market power as do enterprises producing goods for which there is no alternative supplier and limited substitution possibilities (eg water).

Another factor which can influence the choice of how extensive regulation should be is certainty. A regulated environment may provide investors with a greater degree of certainty than would occur if only general monitoring policies are employed. In the latter case, there is always the threat of action, but it is seldom clear if action will be taken and, if so, its outcome. AGL addressed this in the following terms:

> ... we believe that systems which defme the rules are fairer on all parties than ad hoc and indeterminate systems which tend to be open to political manipulation.

However, even if detailed regulations exist, there may not be greater certainty. For example, as discussed in the following section, price regulation in New South Wales involves regulation in the form of a price capping mechanism. The price cap is intended to be primarily dependent on expected increases in efficiency over the period to which it applies. However, in calculating this factor (‘X’) for gas distribution in Newcastle, AGL itself conceded that:

> The high value of Newcastle's X is purely related to political realities (ie the political desire to reduce the price differential between Newcastle and Sydney).

The cost effectiveness of a detailed regulatory regime compared with more general oversight is an important matter which needs to be considered when determining whether a ‘light handed’ or ‘heavy handed’ approach is appropriate. This involves comparing the expected benefits and costs of the alternative regulatory approaches.

This point, which is also relevant to decisions about the nature of regulatory bodies, is considered below.

Nature and role of regulatory body

There are divergent views about what regulatory tasks could be effectively undertaken by a general body applying provisions applicable to industry generally - such as the TPC - and what tasks would be more appropriately carried out by a specialist body which applies industry-specific regulation. Examples of specialist regulatory agencies in Australia include AUSTEL and the Australian Broadcasting Tribunal.

The choice between a general and a specialist body requires consideration of various factors including:

- *the powers vested in general bodies* - provision exists to deal with the use of market power and/or discriminatory pricing under Sections 46 and 49 of the Trade Practices Act. Section 46 stipulates that a corporation shall not take advantage of market power for the purpose of: eliminating or damaging a competitor; preventing entry; or deterring or preventing competitive conduct. Section 49 prohibits anti-competitive discrimination, including discriminatory pricing. However, as Section 49 applies only to activities classified as ‘goods’, it would not appear to encompass all activities of the electricity and gas supply industries. Under Section 17(3) of the Prices Surveillance Act 1983, the Prices Surveillance Authority is required to have particular regard to:

  > the need to discourage a person who is in a position substantially to influence a market for goods and services from taking advantage of that power in setting prices.

  The principal powers of the Authority enable it to consider notifications of price increases proposed by persons declared under Section 21 of the Act and, with the approval of the Minister, conduct inquiries in relation to prices.

- *regulatory capture* - this refers to the possibility that a specialist regulatory agency may over time become so close to the industry it is regulating that it virtually becomes an adjunct to the industry, working towards furthering the interests of the industry rather than those of the nation as a whole.

- *administrative costs* - the cost to government of maintaining a specific regulatory agency would probably exceed the costs which would be incurred if an existing general body were employed. Further, greater demands (and hence greater costs) may be made on industry by a specialist monitoring body compared with a general agency. Differences in costs have to be set against the expected benefits - in the form of increased efficiency of industry operations - that would result from the two alternative regulatory regimes.

- *resource availability* - at the draft report hearings, a number of participants (eg AGL and ECNSW) questioned whether the TPC has either sufficient staff or staff with the necessary technical expertise to regulate effectively the electricity and natural gas industries in Australia. In response, the TPC stated that:

> It is, however, difficult to be precise at this time about the additional resources which might be required by the TPC, although requirements should be more modest than for an industry-specific approach ... it could be argued that each and every industry with which the TPC deals requires some such [technical] knowledge. This does not prevent the application of the TPA to the great bulk of the economy (including some sectors like aviation and the waterfront which are undergoing restructuring).

- *the nature of the regulations* - the more highly regulated an industry is, the greater the likelihood that oversighting will require a specialist body.

The Commission's position

All of the factors outlined above have influenced the Commission's judgments concerning the regulatory environment which it considers should apply to the electricity and gas supply industries. However, in formulating its proposals, the Commission has given considerable weight to the fact that the direct and indirect costs of industry-specific regulation can be significant and that, in recognition of those costs, there must be a demonstrated need for such regulation.

6.2 Regulation of gas transmission and distribution tariffs

In Queensland, the transmission network supplying Brisbane is privately owned and operated by AGL The predominantly privately owned pipeline between the Amadeus Basin and Darwin is operated by Northern Territory Gas Pty Ltd - an AGL subsidiary. Neither owner is involved in the distribution of the gas it carries. The major natural gas transmission pipelines in other states and the Gladstone pipeline in Queensland are publicly owned.

Private utilities reticulate natural gas in New South Wales, the ACT and Queensland. In Western Australia, South Australia and Victoria, distribution is undertaken by publicly owned utilities, although two of the utilities - GFCV and Sagasco - have private equity of between 20 and 30 per cent.

All private gas utilities are subject to some form of tariff regulation. Its primary purpose is to curb the potential for utilities to exercise market power. For example, when making changes to its Gas Act, the New South Wales Government stated that:

> Because the Australian Gas Light Company utilities have a virtual monopoly-type market position, a form of price regulation is essential to protect gas users from monopoly pricing behavior.

The mechanisms currently employed vary between states/territories.

- In Queensland, the operations of gas distributors prior to 1988 were restricted with respect to capital raising, dividend payments, profit distribution and pricing. The old arrangements required gas utilities to demonstrate that price rises were ‘fair and reasonable’. A review of the Act found these restrictions to be intrusive while achieving limited benefits. The new arrangements do not directly control prices or profits. Distribution utilities are free to set tariffs in accord with market signals, subject to the requirement that suppliers with standard schedules advertise the changes. However, the amendments allow the Minister to establish a Gas Tribunal to investigate and, if necessary, recommend maximum prices.

- In the Northern Territory, pipeline tariffs must be based on ‘normal business practices’. If the parties fail to reach agreement, the Energy Pipeline Act 1981 provides the Minister with powers of direction. At present, the only customer of the Amadeus Basin - Darwin pipeline is the Northern Territory Government.

- In New South Wales, AGL's operations were subject to controls over profits and prices. Amendments to the New South Wales Gas Act in 1990 replaced these controls with a price capping mechanism. The new mechanism, which consists of two main components, is modelled on that applying to British Gas in the United Kingdom. Under the gas component, the utility is able to pass any change in the average purchase price of gas on to its tariff or non-contract customers. This presumes that the price of gas to the utility is beyond its control. Under the non-gas component, the utility is able to pass on to its tariff customers an increase equal to the CPI less an allowance for efficiency ‘X’. Consequently, the utility has to reduce its non-gas costs by more than ‘X’ to increase its profit margin on sales. The mechanism places a ceiling on the annual increase in the average price of gas sold in the gas tariff market (ie customers using less than 10 TJ of gas per annum). In 1987-88, this market accounted for less than 20 per cent of all gas sales in New South Wales. While the price of gas sold under contract is not covered by the arrangement, provision exists for the Gas Council to monitor and, if necessary, control prices.

- In the Australian Capital Territory, variations to tariffs must be authorised by the Minister. Additional controls apply to the payment of dividends and profits. These controls and other aspects of the regulatory framework applying to the Territory's sole gas utility, The Natural Gas Company (formerly AGL Canberra), are currently under review.

A common criticism of profit regulation is that it encourages an input mix which will not minimise costs. This argument, first put forward by Averch and Johnson (1962), suggests that a firm constrained by a maximum rate of return which is less than its cost of capital will employ additional (and excessive) amounts of capital to increase the base on which it can earn the stipulated rate of return.

Rate of return regulation applied to private gas utilities in Australia has been based on equity. If the equity base can be expanded, this form of regulation will not limit profits. Such a constraint may also encourage a utility to attempt to channel profits into excessive or ‘padded’ costs.

AGL stated that the previous system of pricing and profit controls was unsatisfactory in a number of ways. The company said that it did not provide a financial return sufficient to permit it to maintain its distribution network. Consequently, the company was forced to let its network deteriorate. AGL said that the former price and profit regulation created uncertainty and that it wishes to persist with a CPI-X arrangement for some time to allow its effectiveness to be evaluated.

The use of CPI-X is seen as providing utilities with a greater incentive to operate efficiently and to reduce uncertainty. However, the efficiency effects of CPI-X from the viewpoint of the gas distributor are not clear. The incentives for better performance may be greater since any efficiency gains (cost improvements) beyond the required rate ‘X’ can be retained by the distributor. However, this is dependent on the level of ‘X’. If ‘X’ corresponds to the recent and prospective productivity performance of the gas distributor, the incentives for additional cost efficiency will be severely blunted. Also, it has been argued that a CPI-X approach evolves, in the medium term, to a profit limiting mechanism. This occurs because governments will tend to increase the value of ‘X’ in periodic reviews if observed past profits are seen as above industry averages, and reduce it if profits are perceived as relatively low. This was acknowledged by the New South Wales Gas Council at the draft report hearings:

> ... the examination of profits would clearly have to be taken into account when reviewing the formula and the operation of the formula.

In this light, CPI-X would have the same faults (eg cost-padding and inefficient increases in capital or equity) as direct profit controls.

Having to calculate an appropriate value for ‘X’ is another drawback to the use of CPI-X. It can impose considerable costs on the administering body and on gas utilities. Additional costs arise if the control mechanism incorporates appeal provisions (eg New South Wales legislation provides for the appointment of a Review Panel if irreconcilable differences arise between the Gas Council and the gas distributor). If a CPI-X approach were adopted, a national level approach to setting ‘X’ may reduce administrative costs.

The effect of CPI-X regulation on tariff structures is less clear. The introduction of a price cap based on an existing tariff structure could impede the capacity of gas utilities to implement more market oriented tariffs. The broader the range of user groups subject to a price cap, the greater will be the scope for adjusting tariff relativities. The possible need for adjustment to the structure of prices within the New South Wales gas market has been recognised by the government and the Gas Council is currently examining the issue of rationalisation of tariffs between the various regions serviced by AGL

While AGL's contract sales are not subject to CPI-X regulation, provision exists for the Gas Council to monitor and, if necessary, control the price of gas sold under contract. The basis for exempting the contract market from the price cap rests on the notion that, first, large users are important to AGL's continued viability and thus have some market power and, second, that customers in this market have access to alternative fuels and, as a consequence, are less prone to exploitation by the gas supplier. However, gas tariff customers seem to have similar substitution possibilities. Gas and electricity are ready substitutes for cooking and for space and water heating - the major uses of gas in the domestic sector - and high estimates of cross-elasticity between gas and electricity submitted by ABARE suggest that domestic electricity tariffs effectively determine domestic gas tariffs. In any event, for some industrial users there is little ability to substitute for gas in the medium term (eg where gas is used as a feedstock). Further, to the extent that the efficiency factor ‘X’ is set ‘too high’ and/or the utility desires to raise its profit margin, it may seek to raise prices in the contract market to offset less profitable sales in the non-contract market. If a price capping mechanism is to be used, it would be more appropriate to apply it to all sales, not just to tariff customers.

In view of the undesirable effects of price and profit regulation, the Commission considers that ‘light handed’ regulation including monitoring by bodies such as the PSA and the TPC may give rise to lower regulatory costs and fewer distortionary effects than would ‘heavy handed’ regulation. Moreover, to the extent that the abolition of exclusive franchises (as proposed in the next section) would result in some increases in competitive pressures, the opportunities to exercise market power would be reduced. In view of these factors, the Commission considers that reliance should be placed on ‘light handed’ regulation in the first instance. If this is shown to be inadequate in constraining the behaviour of a market dominant firm, a heavier handed approach involving an industry - specific monitoring body and a price-capping formula is warranted In these circumstances, the creation of a national body would avoid the costs of having multiple state monitoring agencies with different and possibly conflicting criteria.

6.3 Franchise terms and conditions

This section discusses three aspects of the franchise arrangements applying to private gas utilities: the exclusive nature of franchises, ownership controls, and franchise terms and fees.

Exclusive franchises

Authority to transmit or reticulate gas is provided to utilities through a franchise, a licence or an Authorisation (all subsequently referred to as a franchise).

Private transmission utilities in Queensland and the Northern Territory do not have exclusive rights. In Western Australia and New South Wales, the public transmission utilities (SEC WA and TPA) do not have an exclusive franchise. However, the transmission franchise issued to the public utilities in Victoria and South Australia is exclusive.[2]

PASA indicated in oral evidence that its ownership of the transmission facilities accorded with competitive neutrality: ownership of those facilities by either ETSA or Sagasco, which are both competitors and the major gas purchasers, might allow one an uncompetitive advantage. This reasoning does not apply in Victoria: GFCV has the sole franchise for transmission and distribution. In Western Australia, where SECWA is also a major player in transmission, there is no need seen for an exclusive transmission franchise. Indeed the Government of Western Australia sees important benefits in having a non-exclusive franchise:

> While the deregulation of the domestic gas market was intended primarily to stimulate oil and gas exploration, it also has the potential to subject SECWA to competition from new suppliers of natural gas, particularly as companies will be permitted to construct and operate private pipelines to allow the commercial marketing of gas.

The argument that a utility should have a sole franchise in its region to reduce the potential for misuse of market power ‘by others’ is difficult to sustain. Whatever mechanisms do exist to forestall the sole franchise holder from misusing power can be applied to multiple franchise holders. More importantly, entry restrictions increase, rather than reduce, the market power of a transmission utility.

BHP Petroleum stated that exclusive franchises for pipelines retard the development of new markets and interstate sales of gas. Indeed, exclusive transmission franchises prevent direct dealings between gas producers and end-use customers. BHP Petroleum contends that this prevents the negotiation of ‘the best deal for both parties’. Similarly, Sagasco commented that the sole responsibility vested in PASA to negotiate South Australia's gas needs with producers:

> ... does not appear to benefit either producers or consumers of natural gas, and may in practice only delay pricing agreements.

As for gas distribution, in Australia this is mostly done through exclusive franchises. Esso claimed that the abolition of exclusive distribution franchise areas would ‘contribute to increased competition and thus improve efficiency’. Legislative changes in Queensland in 1988 permitted competition between natural gas and LPG. In a recent discussion paper (Queensland Government 1991, p. 30), it was stated that the changes have:

> ... exposed both the natural gas and the LPG markets to competition and have resulted in lower gas prices in some areas formerly covered by exclusive franchises.

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2 While the Gas and Fuel Corporation Act states specifically that GFCV has the exclusive right to transmit and reticulate gas in Victoria, there are provisions for the Governor in Council to authorise a person other than the GFCV to transmit and supply gas in a specified area or for a specified purpose.

AGL argued in favour of sole distribution franchises. In New South Wales, Authorisations to distribute natural gas in each of a number of regions throughout the State are effectively held by AGL The company contended that neither its Authorisations nor the provisions of the New South Wales Gas Act would prevent another party from distributing gas in competition with AGL However, it stated that:

> There is little doubt that two distributors will not compete head to head through separate (duplicate) distribution systems in the same street ... economics will dictate that two distributors divide up a single natural franchise area into two networks. This ... would result in duplication or under-utilisation of feeder mains.

AGL is concerned that it faces a single natural gas producer and it thus does not support action which would neutralise 'the present countervailing force provided by AGL as the single buyer'. On the other hand, the New South Wales Gas Users Group said that 'both the producer and the distribution utility have sought to exploit their respective monopolistic positions'. However, to the extent that problems do arise in dealing with a single gas producer, measures other than establishing a 'countervailing' monopoly could be used. For example, difficulties could be referred to the TPC.[3]

It is sometimes claimed that exclusive franchises are required to prevent wasteful duplication of infrastructure. However, the Commission considers it is unlikely that there would be significant duplication of gas networks. This issue is discussed in relation to natural monopolies in the following chapter.

One of the costs sometimes associated with the grant of an exclusive franchise is that distribution utilities are obligated to distribute on request. For example, Gas Corporation of Queensland stated that is has 'an obligation to supply to a reasonable demand, including small domestic customers'. Similarly, AGL believes it has an obligation to supply, irrespective of the economic return. It would not be appropriate to impose such a requirement if the exclusivity of distribution franchises were terminated.

Exclusive franchise arrangements can contribute to inefficiencies by insulating franchise holders from competitive pressures. They can also stifle development opportunities. The Commission considers that all exclusive franchise arrangements should be terminated. A necessary corollary is that gas distribution utilities should not be obligated to supply gas on request.

Ownership controls

Dealings in the share capital of AGL in New South Wales and Allgas Energy Ltd (Allgas) in Queensland are restricted by legislation. The relevant Acts relating to AGL and Allgas restrict individual shareholder investments to 5 and 12.5 per cent respectively.

[3] The TPC originally authorised the formation of a monopoly supplier of Moomba field gas to facilitate its development.

In both cases, the controls were intended to ensure security and continuity of gas supply following takeover attempts. At the draft report hearings, AGL stated that a ‘loophole’ in the legislation had permitted one company (Industrial Equity Limited) to acquire over 30 per cent of its shares, but that it only has a 5 per cent voting right.

Legislation also inhibits ownership changes in Sagasco. The parent company - SAGASCO Holdings - is unable to sell or deal in its gas utility shares without a special resolution of shareholders. Around 21 per cent of its shares are held by private investors. The remainder are held by the South Australian Government Financing Authority.

Some of the reasons for ownership controls were outlined by participants at the draft report hearings. For example, the New South Wales Gas Council commented that one reason for the restrictions is to:

> ... prevent take-overs by parties which do not have the interests of New South Wales gas consumers in mind. That could be a case of a producer in another state or a supplier in another state or a distributor in another state.

The Gas Council stated that controls over share transactions are also appropriate to avoid take-overs being undertaken for ‘commercial reasons other than the financial or operational enhancement of the company’ which could jeopardise supply security. The Council cited asset stripping as an example of what could happen in the absence of ownership controls. However, if there are surplus assets, asset stripping could be an efficient activity. The likelihood of asset stripping proceeding beyond the level required to function efficiently would be moderated by the realisation that this would reduce the utility's market value.

In supporting continuing ownership controls, AGL also expressed concerns about the possibility of take-over abuses and other ‘opportunistic’ forms of behaviour. It commented that:

> A shareholders restriction achieves the aim of discouraging speculative activity in utilities in a less complicated way than, for example, the making of lists of "undesirable" shareholders which, given recent financial history, could be circumvented anyway.

Gas Corporation of Queensland expressed contrary views, submitting that ownership controls should be ended.

> One of the most effective ways of avoiding a take-over is to operate at maximum efficiency. Limited shareholdings only encourage inefficient operations.

The Commission does not consider that controls which preclude ownership changes are necessary to guarantee continuity and security of gas supply. If this were the case, similar controls would be warranted for a range of enterprises which supply ‘essential goods’ (eg steel, glass, medical supplies and major food items). Furthermore, ownership controls do not prevent existing owners from engaging in asset stripping and other practices which the controls seek to prevent.

Regulations which prohibit or limit trading in share capital remove an important discipline on the management and operation of gas utilities by providing them with immunity from takeover. The Commission is unable to identify any current justification for shareholding restrictions and recommends that they be discontinued.

Franchise terms and related fees

In Queensland, franchises to operate gas reticulation systems have no fixed term. They remain in force unless the franchisee is considered to have breached the conditions of the franchise. Prior to August 1990, franchises in New South Wales were renewed annually. Now Authorisations are issued without any fixed term although under the Act the Minister can, after 10 years of operation, advise AGL as an Authorisation holder that the Authorisation is to be revoked in 10 years time. Thus, AGL has an effective minimum of 20 years. An Authorisation fee applies. Within the Australian Capital Territory, a franchise condition applies with no provision for a licensing fee. In each instance, there are provisions which allow for immediate revocation if the franchise holder does not comply with franchise conditions.

Annual licensing provisions could result in frequent ownership changes and high transaction costs. On the other hand, 20 year Authorisations weaken the penalties for poor performance and diminish incentives to operate efficiently. While New South Wales legislation provides for revocation if a licence holder does not conform with Authorisation conditions, this does not mean that supply inefficiencies could not persist for many years and significantly impair the competitiveness of user industries. It would be possible to introduce more rigorous monitoring arrangements, perhaps involving regular public reviews to assess performance. However, a major shortcoming of this approach is its inability to determine whether the incumbent's performance would or would not be improved on by an alternative supplier. This can only be determined if some market-based test applies.

Central to any judgement about the most suitable duration for a franchise is the question of competition. How much competition is a gas utility likely to face? Given the nature of the activity, a gas utility is highly unlikely to experience the competitive pressures faced by most other industries. Thus, the Commission considers that there is a case for not providing franchises for too long a term. Nevertheless, franchises must provide holders with the security to permit them to invest in maintenance and new infrastructure.

Gas utilities claimed that a 10 year franchise period - as proposed by the Commission in its draft report - would stifle investment as it would not allow gas companies sufficient time to achieve a return on their investment. Some (eg AGL) claimed that a 10 year franchise would also provide the holder with an incentive to withdraw from maintenance and asset replacement and ‘strip cash out of the operation’. AGL's argument suggests that that incentive would be reduced with a franchise that is considerably shorter than 10 years (to avoid the repercussion of neglect of assets) or is of infinite duration (to provide for rolling capital investment programs). However, provided the value of a utility's assets can be ascertained at the end of a franchise period, there would be little incentive for a franchise holder to act in this way. If distribution assets were, for example, allowed to run down, the overall value of the utility would be reduced. This would, in turn, be reflected in a reduced payment on exit from the industry.

Similar considerations apply to the effect of a finite franchise period on contracts. More specifically, the Commission does not consider that a fixed franchise period would (as contended by GFCV) prevent a franchise holder from being ‘able to enter any worthwhile purchase contracts as they neared the end of their tenure.’ Profitable investments, albeit in terms of physical assets or contracts for the sale of gas, would be reflected in a higher valuation of a utility at the end of the franchise period.

It is not possible to determine with any precision the appropriate duration for franchises. However, the Commission considers franchises in the vicinity of 10-15 years would provide franchise holders with some security and by allowing for the possibility of new entrants at the end of the period safeguard against ongoing inefficiencies.

Ongoing monitoring by government during the franchise period to ensure that franchise conditions are being adhered to (eg to check that market power is not being abused) would also provide checks on performance.

Two related issues concern, first, the method by which franchises are allocated and, second, whether the owner of the franchise owns both the physical assets (ie the pipeline network and associated infrastructure) and the right to operate in the franchise area, or just the right to operate.

Franchises could be allocated in a number of ways. The Commission prefers sale by public tender. Two forms of sale are feasible.

Under the first form, the property right over the franchise area would be sold to the highest bidder. In this case, the bids would reflect any ‘monopoly rent’ expected to be earned from the franchise right. This form of tender would not, however, ensure the utility charged an efficient price. It would merely allow some, if not all, of the excess revenue to be collected by the government instead of by the utility. In these circumstances, users would generally face charges which exceed supply costs.

An alternative form of tender would entail inviting bids for supplying gas to users (net of the cost of gas) over a specified period of time, with the lowest bidder being awarded the franchise. Theoretically, this form of tender should result in an efficient price being charged by the utility as the rent is competed away by the tender process.

In practice, both forms of tender could be imperfect. In the first form of tender, insufficient competition could allow the successful bidder to collect all or part of the monopoly rent. Under the second form, contracts between the Government and the successful bidder may need to be very detailed and extensive monitoring could be required over the term of the franchise. In both instances, there is a possibility that the incumbent will be advantaged because he possesses information which is unavailable to other bidders. This is a problem which exists in the tender of many activities (eg contracts for the overhaul of electricity generators).

At the draft report hearings, the New South Wales Gas Council and AGL advocated that franchise holders be selected having regard to a range of criteria intended to ensure that they are suitably able to undertake ‘the important community function that energy utilities perform’. For example, AGL proposed that prospective franchise holders should be selected having regard to:

- capability to operate a gas system;
- ability to raise necessary finance;
- past business record;
- quality and integrity of Directors and Management; and
- experience in a business where long term returns are achievable at the expense of short term gains.

Pre-selection of tenderers is a normal commercial practise. However, criteria such as those outlined above require extensive subjective judgement and appear to discriminate against new entrants to the gas industry. In the Commission's view, selection of

franchise holders for both existing and new franchises should be on commercial grounds and relate mainly to tender prices.

Mainly because there is a greater likelihood of efficient pricing practices being employed, the Commission considers that franchise rights should be allocated by tender to the party bidding the lowest price for electricity or gas supply over the franchise period. The Commission can see no reason why franchises could not be sold or transferred within the franchise period.

A central question concerns the ownership of specialised assets. Should they remain with the current owner or should they be acquired by the new franchise holder? If the assets are not owned by the franchise holder, the assets may have to be held by government. In this case, conflicts could arise over both maintenance and network extensions. The major advantage would be the avoidance of problems in valuing specialist assets, for which no ready market exists, each time a franchise changed hands.

The valuation of assets may be a complex task. However, asset valuations have been required for past takeovers in Australia's gas industry and are also undertaken periodically for accounting reasons. Moreover, difficulties in valuing assets are not unique to energy utilities. Similar problems exist in valuing assets held by mining ventures and many other businesses which employ assets that have no alternative use.

Although there may need to be an arbitrated solution, the Commission considers that it would be preferable for franchise holders to own the assets rather than just have an operating franchise with the specialist asset being held be another party - probably government.

The Commission considers that successful tenders for franchises should be required to purchase the assets specific to the franchise area Thus, if a franchise changes hands, the successful tenderer would be obliged to buy the assets of the former owner.

The basis for franchise fees varies. In New South Wales, the fee is directed at financing the administration of gas regulation and a contribution to an energy research and development fund. In Queensland, the rationale for the fees is not clear. In most instances (eg Allgas and Gas Corporation of Queensland), the fee is based on the energy content of gas sold. Sagasco pays a fee (5 per cent of revenue), but other public utilities are not subject to such fees.

In many respects, franchise fees have been tantamount to taxes. As stated by AGL:

> The philosophy of using licence fees and charges as a revenue raising mechanism gives the wrong market signals and the market will therefore be disturbed.

Provided there is a mechanism to ensure that gas utilities cannot exercise market power to earn excessive profits, the Commission can see no grounds for governments charging franchise fees relating to sales values or volumes. Franchise fees should be charged only to the extent required to cover the costs of government administering necessary gas regulations and should apply to both private and public utilities.

6.4 Trade in natural gas

With the exception of the Moomba-Sydney pipeline operated by TPA, significant domestic trade in natural gas is limited to intra-state trade. Hence, the major natural gas markets, other than New South Wales, are supplied with gas drawn from within the state/territory involved.

While there are reserves of gas in the south-east (Bass Strait) and in the CooperEromanga and the Amadeus Basins in Central Australia, the industry believes that South Australia and East Coast gas markets will eventually have to be supplied from reserves in the north-west of Australia. In the interim, new pipelines are likely to be required to draw down existing fields. Some possibilities identified by AGL Petroleum included:

- Amadeus Basin (Northern Territory) to Moomba (South Australia) or to Mt Isa (Queensland);
- South-West Queensland to Moomba (South Australia) or to New South Wales via the TPA pipeline; and

- Bass Strait (Victoria) to New South Wales via an interconnection between the existing GFCV and TPA pipelines.

The AGA (1988), in its Gas Supply and Demand Study (Second Report), highlighted a number of other potential gas pipelines with varying time horizons. The study (p.1) observed that:

> In the future, as the Gippsland, Cooper/Eromanga, Amadeus and Surat/Bowen resources become depleted, the economic case for interconnection between States becomes increasingly attractive. The question is not whether total natural gas reserves are adequate, but how and when to connect State markets to reserves adequate for many decades.

That study examined three possible scenarios for the utilisation of Australia's gas reserves. It found that there are benefits from pooling together all eastern states gas reserves to achieve simultaneous depletion. This would minimise the ‘build-up’ period for the supply of gas from the north-west and permit scale economics to be realised as quickly as possible.

In its submission to this inquiry, the AGA stated that:

> The principal issue is the extent to which the national pipeline network, required by 2010 or earlier, will be allowed to evolve in an economic way. An economically preferred evolution would require unhindered interstate movement of gas, in particular from Victoria to either or both NSW and South Australia. The requirement originates in the fact that, on current trends, the source of gas serving NSW and South Australia is expected to deplete about ten years before that serving Victoria.

The New South Wales Government stated that there is a need for ‘long term planning’. It saw a significant role for government in this activity:

> Ensuring that New South Wales has access to secure future gas supplies is a responsibility of both the private gas industry and the Government. The Government is committed to playing a positive and constructive role ...

In contrast, several participants, including AGL Petroleum, Esso, BHP Petroleum and Shell, stressed the need for the future development of transmission pipelines to be ‘market driven’ and the importance of removing any institutional impediments to the interstate movements of gas. AGL commented that private sector interests would assure the most appropriate outcome and that interstate trade should be ‘initiated by the players in the market and co-ordinated by a national body such as the AGA’.

Similarly, AGL Petroleum commented that:

> Since the upstream gas exploration, production and transport industry is exposed to significant risks, it should be the province of private enterprise which has shown a historic willingness to participate in this area, rather than Government.

The Commission supports the view that new gas pipeline developments are best left to the private sector, including those which might be required to access any new supplies discovered in existing fields.

Apart from the exclusive franchising arrangements outlined above, the major institutional impediment was said to be state government policies which restrict the usage of gas in certain applications or place restrictions on interstate trade. This was said to affect both the incentives to explore for natural gas and the prospects for new interstate transmission pipelines.

Prior to December 1988, the Queensland Government would not permit gas in the Queensland section of the Cooper/Eromanga Basins to be sold to South Australia. However, in-principle agreement has now been reached between the Queensland Government and gas producers in south west Queensland to permit the supply of up to 300 PJs of natural gas to South Australia over the next ten years. The agreement is conditional on producers ensuring there is sufficient gas in the region to satisfy Queensland's future demands.

In response to the Commission's draft report, the Queensland Government stated that:

> ... the State Government has a responsibility to ensure a sufficient supply of gas for existing customers. 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.

In South Australia, the Natural Gas (Interim) Supply Act 1985 limits any further supply of gas from South Australia to New South Wales in excess of existing contracts without Government authorisation. That Act also effectively repudiated, initially at least, the agreement between gas producers and AGL on the supply of natural gas for the New South Wales market. The Commonwealth Government's desire to legislate away the contractual arrangements between TPA and AGL provided another example of sovereign risk impacting on interstate trade in gas.[4]

Recently, the Northern Territory Government refused a proposal that gas from the Amadeus Basin be supplied to South Australia.

The use of natural gas for electricity generation in new power stations was prohibited in Victoria for some years. However, NREC (1988, p.131) concluded in a report to the Victoria Government in 1988 that:

> ... considerable benefits would result from the inclusion of up to 500 MW of additional gas fired plant in the Victorian system.

The Committee also observed (p. 126) that:

> The use of natural gas for electricity generation should not be regarded as different to its use for any other purpose, provided that the appropriate economic return to the community is achieved.

Following that report, the Government announced that it would permit up to 500 MW of new generating capacity to be gas-fired, but only for intermediate or peak load plants.

4 Sovereign risk refers to risk undertaken by entrepreneurs that governments will subsequently change ‘policy’ from that which applied when investment desisions were first made.

A recent Commonwealth Parliamentary report into the impact of the greenhouse effect (Senate Standing Committee on Industry, Science and Technology 1991, p. 67) also recommended against using gas for base load power generation because resources are ‘in reality quite small’. The report stated:

> The versatility and attractiveness of gas as an energy source makes it a valuable resource which should be conserved rather than being totally depleted for short terms gains, be they economic or environmental.

BP Australia submitted that the Senate Committee's conclusion is not valid because:

> ... this approach assumes the level [of reserves] is static. The history of resource development shows that this approach is erroneous ... and that much more reserves are likely to be discovered especially if a market is available. The approach also appears to assume a static level of technology in resource using industries using the same resources in the same proportions as today. Every indication is that this won't be the case.

According to BHP Petroleum, the current Victorian Government restriction on the use of gas for electricity incorrectly views gas as a uniquely scarce and diminishing resource. The company claimed that the policy has diminished incentives for exploration and development of additional natural gas reserves in Bass Strait.

Esso commented that the current policy is an improvement on the previous ‘blanket prohibition’, but that the new policy is undesirable because:

> The incentive to explore for additional gas to service the power generation market, particularly the base load component, is practically eliminated.
>
> The SECV is deprived of an energy, source which when used for power generation and in particular base load generation in gas combined cycle plant, is more efficient from a resource and capital use perspective versus the alternative, brown coal.

In 1970, the Commonwealth Government imposed a ban on the export of natural gas to conserve the resource for domestic consumption. In the late 1970s the ban was relaxed to allow the export of some gas from the North-West Shelf. Further export of natural gas is subject to approval by the Commonwealth.

Government policies which restrict the use of natural gas seem to be based on the premise that governments can develop better solutions than those likely to emerge under a marketbased solution. Such solutions have, in the past, proved otherwise and the Commission cannot find any evidence to support this finding. The policies appear to be heavily influenced by energy conservation goals, notions of scarcity and a premium fuel status for natural gas, as well as parochial interests. The end result is that decisions in this area are unduly shaped by political rather than economic criteria, and markets are defined by territorial borders rather than by commercial considerations.

Participants indicated that there are a number of potentially large developments on the horizon. These include the possible interstate pipelines referred to above and new intra-

state transmission pipelines (eg pipelines connecting the south-west Queensland fields and Mt Isa, and a spur line to Gove from the existing Amadeus Basin - Darwin pipeline). Greater use of gas for electricity generation could further accelerate development. In the Commission's view there is a risk that the successful exploitation of some of these developments will be endangered unless commercial considerations are given much greater weight.

The Commission considers that decisions relating to the development of natural gas transmission pipelines and the possible extension of reticulation systems across state boundaries should be market-driven. Accordingly, governments should remove all restrictions on the use to which gas is put and remove restrictions on interstate or overseas trade in gas. The exercise of Commonwealth powers may need to be considered for the removal of state restrictions.

6.5 Summary of proposals

Some regulation of the activities of private gas utilities is warranted to help ensure efficient performance. However, governments concede that some regulation has been obtrusive and ineffective. In some states, changes have been made, but there is still considerable scope for improving the effectiveness of major government regulations and policies that impinge on the operations of private gas utilities. The Commission recommends that:

- gas tariffs be monitored by ‘light handed’ regulation (eg by the TPC). If this is shown to be ineffective, industry specific monitoring involving the application of a price capping formula should be employed;
- exclusive franchises and utilities' obligation to connect new users at concessional
- rates be terminated;
- non-exclusive, tradeable franchises be allocated for approximately 10-15 year periods, and be awarded by tender to that party bidding the lowest price for supply of gas over the franchise period, net of the cost of gas purchased. Franchise holders should be required to purchase all assets specific to the franchise area;
- franchise fees relate only to relevant administrative expenses;
- provisions limiting trading in shares of private gas utilities be abolished; and
- government policies that restrict the use of gas or its sale interstate or overseas be abolished. The Commonwealth should consider using its powers, where relevant, to facilitate abolition of these restrictions.

The Commission considers that these proposals could equally be applied to private utilities which may become involved in electricity distribution.

7 STRUCTURAL CHANGES TO PROMOTE COMPETITION

The current organisation and structure of the electricity and natural gas industries within Australia is such that, even with the removal of legislative barriers to competition, the potential benefits of competition are likely to emerge slowly and to only a limited degree. There is a need to consider initiatives directed at promoting competition within these industries if their performance is to be significantly improved. These encompass separation of some segments within these industries, the creation of multiple electricity generation and electricity and gas distribution entities in most states, and the introduction of an open access requirement for transmitters and distributors of electricity and gas.

Corporatisation of public utilities and changes to the regulatory environment in which they operate will increase incentives for efficient management. In parts of the ESI and NGI, the removal of regulatory barriers to entry should lead to some competition and improve incentives for efficient operation. However, the current organisation of the industries and the dominant position of existing suppliers pose formidable barriers to the development of effective competition, in addition to those arising from the large sunk capital investments necessary to enter these industries. These barriers cannot be addressed by administratively based reforms alone.

In these circumstances, there is a need to consider whether changes to the structure of the electricity and gas industries to actively promote competition are warranted.

The following discussion examines a number of issues associated with structural changes to promote competition. The expected benefits are outlined in Section 7.1. Practical concerns which are sometimes raised in support of leaving existing organisational and market structures unchanged are dealt with in Section 7.2. Mechanisms for promoting competition in the electricity and natural gas supply industries are examined in Sections 7.3 and 7.4, respectively. The Commission's proposals are summarised in Section 7.5.

7.1 The benefits of promoting competition

Some participants doubted that greater competition would increase efficiency. For example, the Queensland Government argued that:

> ... centralised planning of the Electricity Supply Industry has enabled the State to capture the benefits of economies of scale and provide access for all Queenslanders to the benefits of the State's low cost coal resources. ... The performance of less regulated electricity markets has yet to be demonstrated.

But this view was in the minority. The benefits of greater competition were widely acknowledged by inquiry participants. For example, the initial submission by the New South Wales Government stated:

> On balance, a relatively free market may offer a greater potential for improving economic efficiency than available variations on a co-ordinated planning arrangement. Although industry efficiency can increase in either type of model, the free market approach creates an atmosphere more likely to breed continuing improvement through ongoing market pressure for performance (their emphasis).

and further that:

> It is believed that the free market approach has the potential to offer advantages over more traditional co-ordinated planning models in three main areas:
>
> - more appropriate capital investment decisions
> - more pressure to reduce operating costs
> - more economically based pricing arrangements.

Similarly, the South Australian Government indicated its support for the:

> ... consideration of initiatives to increase the level of competition or private sector involvement in the electricity and gas industries, where such initiatives will confer clear economic benefits on the State.

The SECV put the role of structural changes as follows:

> While very major efficiency increases have been achieved by the administrative improvements introduced by local and general management, it has become apparent that further significant improvement will require structural change. Structural change refers to changes to the overall operating linkages within the industry which lead to individual business components responding to externally applied business pressures.

In addition, the SECV observed that for the generating sector of its operations:

> ... the difficulty in achieving the management/union identified operating cost reduction targets at Loy Yang has confirmed the view that the efficient operation of this sector requires increased exposure to competitive pressures.

In its submissions, the Western Australian Government noted that it was considering options for significant structural change in order to foster competition, including the separation of some of SECWA's functions.

For the ESI as a whole, the ESAA observed that it:

> ... believes that increased competition in the industry will lead to improved efficiency.

At the draft report hearings, the ECNSW observed that while the corporatisation reforms referred to in Chapter 5 are:

> ... expected to provide important gains in efficiency, to ensure long term gains it is necessary to couple corporatisation with changes in industry structure.

Despite widespread support for competition and structural change, most energy utilities - and, in particular, publicly owned utilities - vigorously opposed the structural changes advanced in the Commission's draft report without advancing alternative means to promote adequate competitive pressures. Except where governments have insisted, most utilities supported reforms only of the type which they themselves had initiated, even to the extent of denying the relevance to them of measures introduced by utilities in other states/territories. As a result, the degree of change endorsed by most utilities is modest and focuses mainly on administrative measures. It is clear that reforms which might erode utilities' control of their traditional areas of operation are not being seriously contemplated.

The Commission shares the view of most governments participating in the inquiry that administrative change will result in only limited competition. Structural change is necessary to expose the industries to greater competition and create pressures for adjustment and/or improvement on a continuing basis. Administratively based mechanisms must be upgraded or refined and, even then, are unlikely to achieve a similar outcome. Weaknesses in these mechanisms shelter producers from the need to adapt.

This judgment is shared by other participants, including CRA which observed in relation to the electricity industry that:

> It is important to note however, that the magnitude of the recent improvements begs the question as to why the States were as overstaffed and overspent as they were - given that the system which enabled them to become that way is still in existence. It raises the question as to whether the recent improvements can be sustained over time.
>
> It is the CRA view that it is only by subjecting such organisations to competitive pressures (of which interstate rivalry is one example) can sustained world-class performance be expected from the industry.

Decisions by governments in recent years to encourage structural change by removing or reducing legislative and other barriers to competition in areas such as finance, crude oil marketing, parts of telecommunications, domestic aviation and for import competing industries, attest to the growing recognition of the benefits which promoting competition has on economic efficiency.

In short, a key question for this inquiry is how to promote greater competitive pressures to encourage improved performance. However, it is useful first to examine some concerns about the practicality of promoting more competition through changes to the organisation and structure of the EST and NGI.

7.2 Practical concerns

Participants raised a number of practical concerns about promoting competition. These related to:

- the delivery of community service obligations (CSOs);
- system economies from planning and operating an integrated organisation; and
- the natural monopoly characteristics of parts of the industries.

These concerns are addressed separately below.

7.2.1. Community service obligations

As observed in Chapter 5, electricity and gas utilities throughout Australia are required to perform a variety of CSOs. While some are funded directly by governments through revenue supplements to the utilities (eg some pensioner rebates), most are internally funded through cross-subsidies (eg uniform prices, connection 'subsidies' and tariff concessions to domestic and some industrial users). Internal funding of CSOs is currently supported by legislative barriers to competition.

Supporters of CSOs which are presently financed by cross-subsidies maintain that the removal of legislative barriers to competition would deny governments the ability to pursue the equity and development objectives underlying them. While an analysis of the rationale for these CSOs indicates that many are of questionable merit, there are alternative ways of funding them which do not require restrictions on competition. For example, there could be more extensive use of direct funding or the provision of vouchers to users (see Appendix 5).

CSOs in themselves do not represent an impediment to promoting competition within these industries. There are alternative and more effective ways of delivering CSOs than relying on cross-subsidies whose existence depends on legislative barriers to entry.

7.2.2. System economies

Many industry participants claimed that all or some of electricity and gas supply should continue to be integrated within a single organisation to realise savings from system economies.

In the case of electricity, it was claimed that because storage is not feasible and production must be instantaneously matched with consumption to ensure reliable supply, the vertical integration of generation, transmission and distribution within a single organisation is necessary to facilitate coordination of planning and operation. With full vertical integration, a single organisation bears all of the consequences of its activity. In effect, interdependencies between industry segments are internalised within the one organisation which coordinates its activities across the segments. However, it is the form of coordination and the costs of different forms relative to their benefits which is crucial. As discussed in Appendix 10, coordination may be accomplished through full or part integration of industry segments or through coordinating arrangements (such as contractual agreements) between separate organisations.

Judgments differ about the desirable degree of vertical integration in the ESI. In contrast to most parts of Australia, distribution in Queensland and New South Wales is handled by organisations separate from generation and transmission bodies. In the Northern Territory, transmission is largely undertaken by a private entity, while generation and distribution are handled by PAWA. Judgments about the desirable degree of horizontal integration also vary. Queensland, New South Wales and Victoria have multiple distributors while, in the other states and the territories, distribution is handled by one body.

Within the gas industry there is a greater diversity of organisational forms. Some public utilities are involved in both transmission and distribution (eg GFCV and SECWA) but, in most cases, these functions are performed by separate organisations (eg TPA and AGL in New South Wales and PASA and Sagasco in South Australia). In the Northern Territory, the gas industry comprises three main groups - gas producers, pipeline operators and distributors. While there is some vertical integration because AGL Petroleum, through various subsidiaries, is active in each group, the Northern Territory Government indicated that it:

> ... would however be concerned about the potential for restrictive marketing practices to emerge if there was to be an increase in the level of integration.

In Queensland, the transmission of gas from Roma to Brisbane is handled by one private entity, while the distribution of natural gas in Brisbane is handled by two private utilities. In these cases, contractual arrangements rather than vertical integration facilitate coordination and planning. Contractual arrangements or alternative coordinating mechanisms (such as power pools) are used in a number of other countries (eg the United States) to achieve a similar outcome within the electricity industry (see Appendix 10).

The differing industry structures for production and delivery of electricity and gas, both in Australia and overseas, indicate that there are varying assessments as to what represents the least-cost approach. They suggest there is no overwhelming need to have vertically integrated organisations, nor for distribution to be handled by the one body in a particular state/territory.

In practice, a high degree of integration - and the associated tendency for a single organisation to handle most if not all industry functions - seems to be associated with an administratively based or centralised planning approach to various institutional arrangements (eg obligations to supply customers, maintain high levels of system reliability and responsibilities for system planning) rather than a desire to satisfy these arrangements in the most efficient way. In less regulated electricity and gas markets, greater reliance is placed on market mechanisms for pricing electricity and gas to users, and meeting their needs for security of access and/or reliability.

While integration may produce benefits in the form of reduced uncertainty and lower costs in organising production and marketing, a balance needs to be struck between the expected gains from integration and those available from making structural changes (which could put these gains at risk) in order to capture the benefits available from greater competition and less regulation.

The existence of system economies is not an argument against promoting competition per se. It does, however, require that the effects on system economies of making changes to promote competition are considered, including the possibility of realising these economies through means other than integration.

7.2.3 The natural monopoly issue

A further consideration impinging on the scope for competition is the existence of natural monopoly elements within the electricity and gas supply industries.

A natural monopoly occurs if the entire output of an industry (or a part of it) can be supplied at lower cost by a single firm than by any combination of two or more firms. This may arise because of economies of scale or scope.

It is sometimes claimed that exposing a natural monopoly to competition could give rise to inefficiencies associated with uneconomic duplication of production and supporting infrastructure and/or market instability. Thus, it is argued, any competition arising from the removal of legislative barriers to entry will be wasteful or destructive.

A major issue concerns the extent to which natural monopoly elements characterise the electricity and gas industries. Given existing technologies, the transmission and distribution segments of both industries are commonly viewed as having natural monopoly characteristics. However, the extent of natural monopoly appears to be greater for transmission than distribution since the advantages of single firm supply in distribution seem to be exhausted at smaller scales than those in transmission. The existence of multiple distributors in the market for electricity and gas in a number of states and in other countries lends support to this view. In contrast, electricity generation and related fuel supply, together with the gas producing segments, do not exhibit natural monopoly characteristics.

These judgments are not new and have been accepted by most utilities. Even so, legislative barriers to competition apply to virtually the entire production and supply process for electricity although, at most, only about 35-40 per cent of that industry (on a cost basis) might be naturally monopolistic.

The transmission and distribution networks associated with electricity and gas supply have a number of characteristics which suggest that the likelihood of wasteful or destructive competition is remote. The substantial initial capital investments (much of which could not be recouped on exit from the industry), the knowledge that existing suppliers are in a dominant position to meet any competitive threat and the existence of long term supply contracts between users and suppliers, are all likely to deter entry, except in the case of those confident of being efficient long term suppliers. In the latter case, entry would clearly be desirable. However, even if a competing supplier only operated for a limited period, or in a limited market segment, this would not necessarily detract from efficient resource use. The possibility of new entrants and of other firms being forced to withdraw from the market are important factors promoting pressures to contain costs.

A further issue raised by the existence of natural monopoly concerns the exercise of market power. In such cases, there will be a need for regulatory provisions governing the conduct or behaviour of the supplier (see Chapter 6). But such provisions should be complemented by removing any legislative barriers to entry so as to expose the single supplier to the threat of potential competition. In general, competitive pressures are likely to be stronger for gas suppliers than suppliers of electricity because most gas markets are subject to competition from alternative forms of energy, including electricity.

The existence of natural monopoly does not justify the retention of legislative barriers to competition. If the transmission and distribution segments of these industries are genuine natural monopolies, such barriers are redundant. If they are not (ie if they are artificial monopolies), barriers to competition will weaken incentives for better performance.

7.3 Promoting competition in the electricity industry

The main forms of current and potential competition in the ESI include:

- Competition between electricity and other fuels (notably gas) in some market segments;
- Wider use of contracting out as an alternative to ‘in-house’ provision of certain goods and services (eg construction and maintenance);
- Competition at the margin through interstate sales of electricity via the interconnected New South Wales, Victorian and South Australian grids;
- Limited competition within the generation segment of the industry from private generators (including cogenerators) with access to the transmission and/or distribution network;

- Competition between states for the supply of electricity on competitive terms (covering both price and quality) to new industries and/or existing industries considering an expansion of their activities (eg aluminium smelting); and

- Competitive tendering for the supply of new infrastructure such as power stations and transmission/distribution network extensions.

The corporatisation reforms proposed in Chapter 5, notably those relating to the removal of controls over the sourcing of inputs and legislative barriers to entry, provide some scope for greater competition. The potential gains from such competition are likely to be worthwhile. However, given the existing structure of the industry, additional competition would apply to only a limited proportion of the industry's activities. The ECNSW (1991) summed up the case for going further than corporatisation when it observed that:

> Corporatisation alone is unlikely to produce sustained benefits for society. Market forces provide the strongest discipline for performance. The performance measures and performance monitoring suggested for corporatisation are surrogate measures to provide market force incentives. Without the necessary pecuniary pressure the long term success of corporatisation is questionable.
>
> Whether corporatisation fosters a competitive environment depends very much on the structure of the industry. To take advantage of corporatisation and the stimulus provided by competition the ECNSW is taking action to seperate grid functions from production functions and to further seperate production functions into internally competing generators.

Governments in Australia (as well as of other countries) are being challenged to consider proposals for restructuring existing arrangements to expand the opportunities for competition and to promote better performance. A central issue is how to ensure open and non-discriminatory access to the transmission grid. Without non-discriminatory access to transmission, the likelihood of new entrants to generation - the most contestable part of the industry - is small. The significance of this issue is widely recognised. For example, the SECV observed that:

> The encouragement of private generation into the Victorian system requires the development of a policy relating to open access to the transmission system. The SECV supports the concept of open access, but reserves final judgment on implementation until a full evaluation of the many technical and commercial considerations is carried out.

Open access to transmission represents a vital first step in increasing the role of market mechanisms compared with centralised planning in shaping the pricing and investment decisions of the ESI. Accompanying changes to the generation and distribution side of the industry could well see the emergence of quite a different set of industry and regulatory arrangements as this decade unfolds. A more market oriented ESI in Australia, along the lines of that evident in parts of the United States and Europe, and that developing in the United Kingdom and New Zealand, could well exhibit the following characteristics:

- The separation of transmission from generation with open access to the grid to promote active competition between generators for the supply of electricity to distributors/users;

- Direct negotiations between generators and distributors/users for the supply of electricity in the absence of supply obligations and exclusive franchises on sales in a given area;

- Significant re-alignments in prices as they move to levels which better reflect the true costs of supply;

- Greater exchanges of electricity between states through an enlarged south-east (SE) Australian electricity grid via long term contract as well as opportunity sales, with investment decisions about new capacity being based only on commercial considerations; and

- Greater transparency in pricing to users, with separate and identifiable charges for bulk electricity, transmission and retail electricity.

However, as observed by the ESAA:

> There are many complex issues for consideration when determining the most appropriate structures, particularly with respect to separation of the major components. These include the development of policies for open access to the transmission system, and development of contract and pricing policies to operate between each sector.

Reflecting the complexity of these issues, some electricity authorities indicated support for a staged process of reform at the draft report hearings. Such a process would be centred on making changes which are likely to be effective now and which can support more extensive changes in the future if trials of different arrangements in Australia and developments in countries such as the United Kingdom and New Zealand are shown to be worthwhile. Four stages appear to be envisaged, namely:

- commercialisation leading to corporatisation of appropriate parts of the ESI;

- adoption of an interim industry structure involving the ring fencing of some industry segments and the provision of open access to transmission grids (including the development of an enlarged SE Australian grid);

- assessment of the appropriateness of more extensive reforms directed at increasing the market orientation of the ESI; and

- adoption of further reforms, provided it can be conclusively demonstrated that net gains will eventuate.

This approach is based on the view that there is considerable uncertainty about the impact of extensive structural reforms on performance, and the consequent risk of making incorrect decisions if reform goes too far too quickly. It needs to be recognised, however, that all policy changes carry an element of risk which cannot be avoided.

The sensible course is to take advantage of all opportunities to improve knowledge where uncertainies are high. But the test for change proposed by ESAA and some authorities appears excessive and seems to be aimed more at preserving the current primary role of electricity commissions than at facilitating change. In particular, these players appear to demand firm empirical evidence of the benefits of change - even though they themselves appear to have little or no empirical evidence to justify their own position. Indeed, in view of the preferential arrangements which shelter energy utilities from normal market pressures, it can be argued that the onus should be on utilities to provide empirical evidence to support the maintenance of the status quo, rather than to demand it of proponents of change.

The subsequent discussion seeks to identify the main issues associated with structural changes rather than to put forward a detailed agenda for reform. Given the complexity of the issues, there will be a need for further analysis. The Commission has sought to focus attention on what it considers to be the priority areas for immediate action and those where further analysis is required if worthwhile reforms are to emerge.

The initial focus is on identifying opportunities for improving access to transmission (Section 7.3.1), and increasing competition in the generation (Section 7.3.2) and distribution (Section 7.3.3) segments of the ESI. A discussion of revised organisational arrangements for promoting the effective operation of the SE Australian electricity system follows in Section 7.3.4.

7.3.1 The transmission grid

The transmission grid links power stations and the distribution segment. As presently structured (with the exception of the Northern Territory), the body owning and controlling transmission is also the body controlling generation of electricity for public sale in each state/territory. This structure gives rise to an access problem for cogenerators as well as new generators.

The access problem

Given the existing industry structure, merely removing legislative barriers to entry into generation is unlikely to be effective in encouraging competition in the supply of generating capacity. As noted by CRA:

> The restricted ability of new suppliers of electricity to gain access to the transmission grid is the major barrier to entry to power generation and to sales and distribution. Without access to the grid neither power generation nor distribution are competitive activities, nor can they begin to be contestable in the sense of being potentially competitive.
>
> ... If there is to be competition between generators on a level playing field, then it is quite inappropriate for one of those generators to control the transmission system.

At the draft report hearings, the ESAA also acknowledged that a major impediment to achieving a competitive environment is the absence of open and fair access to the transmission grid for both public and private generators and distributors.

The integration of transmission and generation within a single organisation thus gives rise to several problems:

- the capacity of the organisation to deter entry by engaging in predatory pricing (ie setting prices at less than short-run marginal costs);
- the absence of adequate information on terms of access and the scope thereby for discriminatory practices (such as inflating transmission charges or varying connection requirements) in the treatment of new suppliers; and
- the absence of clear signals for investment decisions due to inadequate information on grid pricing policies.

A number of possibilities exist to overcome these problems: rely on the provisions of the TPA to promote fair trading; form separate accounting entities within the same enterprise to cover generation and transmission (ie ring fencing); allocate these functions to separate organisations (ie full separation); and apply the first response in conjunction with either of the others.

If the current exemption enjoyed by government bodies is abolished as recommended in Chapter 5, a new entrant could take action under the TPA in the event of a dispute with a transmitter. However, the resolution of such a dispute is likely to be costly and time consuming, and may not yield a clear outcome because of the difficulties of assessing appropriate prices for generation and access terms for transmission where these functions are not separately provided.

An alternative, which was discussed by the ESAA, ECNSW and SECV, would require the establishment of separate business units covering generation, transmission and, where applicable, distribution, within existing electricity authorities. This response - termed ring fencing - usually entails the preparation and publication of separate accounting information for each unit. Parts of the ESI are already moving in this direction. The SECV has established three strategic business units (covering production, power grid and customer services) linked by transfer pricing. According to the SECV:

> The transfer pricing concept was introduced on a trial basis in 1989-90, being fully operational for reporting purposes this year and being used in the budget process for 1991-92.

In its draft report submission, the ECNSW indicated that it was proceeding to separate the accounting records for generation and transmission. According to ECNSW:

> This ground work is necessary to provide a greater understanding of appropriate wheeling charges for electricity.

Ring fencing may restrict the capacity of existing generators to engage in discriminatory practices. It would provide information about the costs and pricing of generation and transmission and yield better pricing and investment signals to potential entrants. An advantage attributed to this approach is that it does not place at risk the perceived benefits of an integrated organisation.

At the draft report hearings, the ESAA observed that:

> The uniform approaches to performance measurement, accounting and reporting currently being developed by the industry and also being addressed by the Special Premiers' Conference Working Group will complement 'ring fencing' as a route to increased competition by facilitating comparisons across State boundaries in Australia and with appropriate overseas components of the industry.

But ring fencing has basic limitations. It is inherently difficult to make an enterprise responsible for bulk generation and transmission behave as if it were two separate entities. Inevitably, the potential for conflict of interest in relation to open access to the transmission grid would remain, with associated incentives for the incumbent to manipulate terms of access, as well as the allocation of overhead costs and asset values used in determining transmission charges. To behave as two separated entities, the transmission division, occasionally - perhaps frequently - would need to act to the detriment of its associated generation division and, ultimately, to the detriment of the corporation as a whole (eg allowing distributors to purchase electricity from independent generators). Concerns along these lines were expressed by CRA during the draft report hearings in relation to the operating practices of Trans-Power - the transmission operator in New Zealand.

A regulatory authority could be used to monitor the ring fencing of generation, transmission and distribution functions. The same authority could then be required to monitor grid access and pricing and/or oversee the behaviour of existing generators, transmitters and distributors. However, even if this were to occur, perceptions of bias because of ownership links could still inhibit new entrants.

An alternative to ring fencing is to separate fully transmission and generation functions, and require that the transmitter provide open access to the grid and treat all generators on an equal basis. The Western Australian Government is currently considering this option. CRA observed that:

> ... stripping transmission from those hitherto responsible for generation, may be necessary to ensure that the party responsible for transmission cannot use this control for uncompetitive purposes.

and further that:

> ... the benefits of a competitive framework are more certain to be achieved if that separation does occur.

Shortly before this report was finalised, the Premier of New South Wales in a statement released just prior to the State elections (Premier of New South Wales 1991), indicated that, if returned, the Government's further initiatives would include corporatising ECNSW by October:

> ... with a clear separation of generating and transmission functions. The Commission's power stations will operate as profit centres, and sell into the Grid through a market mechanism which will be developed and trialled (sic) over the next two years.

Other benefits arising from full separation include improved transparency of access conditions and improved cost and pricing information. This would help reduce uncertainty for new generators and diminish the burden on any regulatory authority responsible for monitoring terms of access and pricing. The TPC acknowledged that vertical separation would reduce the incentives to engage in activities which impede access and simplify regulatory tasks.

The application of an open access requirement on the grid operator would need to recognise the role of past parties in developing and using the grid, say by way of the provision of capital or contract for extended use. The key to an open access requirement would be that any spare capacity would be available to other parties on nondiscriminatory terms and that the grid's capacity could be extended where this was in the interests of the network.

Full separation with an open access requirement would preclude the owner of the transmission grid (the natural monopoly) from competing in generation (the most contestable part of the industry) and distribution. This arrangement would reduce the need for regulation and effectively alleviate the access problem by removing the incentive to deny access or to offer it to other generators on discriminatory terms.

While reducing regulatory costs, full separation may increase transaction costs in seeking to coordinate production, marketing and investment decisions. However, possible increases in these costs need to be weighed against the benefits of stronger disciplines on the costs of generation, as well as the management and pricing of transmission services. Further, because generation accounts for about 60-65 per cent of the retail price of electricity, it is vital to have strong efficiency incentives in this segment of the industry.

Within Australia, the Northern Territory provides an example approximating the full separation of generation and transmission, with PAWA responsible for generation and NT Power (a fully independent and privately owned firm) handling transmission between Darwin and Katherine. This approach, with the addition of a common carrier/open access requirement, has also been adopted in the United Kingdom and has been proposed for New Zealand (see Appendix 9).

The Commission concludes that there should be full separation of generation and distribution from transmission, with an associated open access requirement on the operator of the transmission grid. While such a change is likely to increase coordinating costs between industry segments, it is also more likely to promote open access to the grid on nondiscriminatory terms, with a lesser need for regulatory oversight than the alternatives.

The appropriate functions of the grid operator

Acceptance in-principle of the need to separate fully transmission from generation and distribution would require a number of supporting changes during the transition to the revised structure. It would be necessary to establish separate business units along the lines of the ring fencing approach discussed earlier and accepted by some electricity authorities. Following this it would be necessary to develop procedures for pricing the services provided by each unit through a system of transfer pricing (where formal pricing does not currently apply) in preparation for full separation. This again has been accepted by some within the ESI.

Thus, there is no disagreement between the Commission and some in the industry (ie SECV and ECNSW) on the initial steps which are required for full separation. The hesitancy about the final step - full separation - could be overcome in the light of the results of ring fencing and the introduction of formal pricing arrangements. However, unless these early steps involving transmission are under the control of a group independent of the existing utilities, or unless governments are strongly committed to full separation, its prospects could be slight.

During the transition, the role of the transmitter would change from ‘trading’ in electricity (ie purchasing power from generators and selling it to distributors or users) to operating purely as a transporter of electricity (ie not purchasing electricity and charging for ‘transport’ only). This role change is necessary to ensure that the transmitter focuses on optimising the operation of the grid rather than seeking to profit from wholesaling electricity.

Key issues to be resolved prior to full separation would include: the determination of appropriate functions for the grid operator; the development of transmission pricing; arrangements for handling contingency reserves and emergency supplies; and other agreements for the operation of the system. In recognition of the technical and coordination requirements for the effective operation of the ESI, the Commission considers that the grid operator should ultimately be fully responsible for the:

- operation and maintenance of the grid (including the setting of technical standards for connection to the grid);
- merit order dispatch of generators on the basis of (confidential) information supplied by generators and the costs of transmission;
- pricing of transmission services, subject to regulatory guidelines and oversight;
- joint planning of transmission facilities to accommodate new generating and distribution capacity; and
- other coordination functions covering the scheduling of maintenance by generators and system integrity.

With full separation, the grid operator would be solely responsible for the provision of transmission services and the coordination of the supply system, but would not be involved in the purchase or sale of electricity. This assignment of functions would promote open access to the grid on non-discriminatory terms. As discussed below, this would also require the development of a number of markets for pricing electricity transactions from generation through to users. At present, most of these transactions are handled internally within integrated organisations and there are no market prices for them. The information conveyed in these market prices would provide clearer signals for production and investment decisions, as well as for users.

Regulatory provisions

The Commission considers that, in view of the market power available to the operator of the transmission grid and the desirability of having clear ground rules for access to the grid by generators, there would be a need for regulation of the grid. In order to promote transparency in technical requirements, operating rules and pricing, and to enable public monitoring of the grid's performance, there would at least be a need for guidelines covering:

- exclusion of the transmitter from generation and distribution functions;
- terms and conditions associated with ensuring open and non-discriminatory access to the grid;
- the level, structure and basis of pricing for transmission services; and
- public information disclosure requirements to apply to the grid operator.

Some may judge it desirable to provide additional guidelines covering, for example, acceptable levels of system reliability. Although important, the Commission considers that it would be preferable to allow such operating variables to be commercially determined, with risk and uncertainty being dealt with as in other product markets.

The Commission considers that it would be desirable to provide for regulatory oversight of the process of transition to a fully separated structure. This would involve oversighting the development of new operating procedures, as well as monitoring market conduct. A number of possibilities exist including: giving the TPC a special brief (by way of a Ministerial Direction) to oversee the process along the lines of its waterfront and domestic aviation monitoring and reporting briefs; employing a similar mechanism to enable the PSA to undertake the task; and setting up a specialist body (with a sunset clause) to perform the same function.

Once fully operational with full separation and an open access requirement, it may be sufficient to rely on the general provisions of the TPA (or its state equivalent) and the Prices Surveillance Act to encourage appropriate behaviour by the transmission operator. Included in such a brief could be a requirement to monitor performance against these guidelines and regulatory provisions. This arrangement would, of course, also be dependent upon agreement being reached by all relevant governments that the current exemptons from the TPA and the Prices Surveillance Act enjoyed by public bodies should be removed.

As noted by the TPC, this arrangement could raise some difficulties. For example, under existing legislation some pricing issues (eg those relating to returns earned by industry participants) would need to be addressed by the PSA while other pricing issues (eg discriminatory prices) would be subject to the TPA. However, where natural monopoly elements are present, as is the case with electricity (and gas) transmission, these issues are not easily separated and it may not be possible to regulate efficiently each in isolation. Consequently, the Commission believes that consideration should be given to modifying the TPA to permit the TPC to address all relevant pricing issues relating to the electricity (and natural gas) supply industries (including monopoly pricing). This might also require legislative change to ensure that Section 49 of the Act (which deals with anti-competitive discrimination) applies to all of the industry's activities, including those which might be regarded as ‘service’ activities. If these changes were to occur, it would also be appropriate to modify existing legislation to acknowledge that Ramsey pricing can be an efficient form of pricing for activities having natural monopoly characteristics, and is not necessarily a form of discriminatory pricing in violation of Section 49 of the Act.

Marketing arrangements

The major means of coordinating supply and demand for electricity would be a power pooling arrangement. Such arrangements are common throughout Europe and the United States. There is a wide range of possible arrangements and pools can be categorised as falling into a continuum from ‘loose’ pools to ‘tight’ pools (see Appendix 10). Despite the wide diversity of pool types, the arrangements can be complex and highly technical. In these circumstances, the Commission has not attempted to specify fully the arrangement which it believes appropriate for a re-structured Australian ESI. Instead it has concentrated on outlining some of the features of a pooling arrangement - notably those relating to marketing - which it considers would best complement the development of a more competitive industry in Australia.

In preparing for full separation of transmission from generation and distribution, it would be necessary to develop various markets as an alternative to the current internal administrative procedures. To some degree, these markets already operate in the Australian ESI (eg wholesale - covering generation and transmission - and retail). Administrative versions of the others - covering the merit order dispatch of generating units and various system controls for ensuring the secure and smooth operation of the grid - already exist. The full development of these markets would require the specification of technical and other conditions for participating in the industry, as well as the access of ‘players’ to the different markets.

A dispatch market would operate to ensure merit order commitment and dispatch of generating units. This would minimise the cost of production for a particular level of demand on the system. A version of this market already exists in each state and for existing interconnections. In a restructured ESL, it would be organised on the basis of generators making bids to the operator of the transmission grid on the basis of their supply costs. For costs to be minimised, it would be necessary to develop a mechanism whereby generators could trade between themselves in order to satisfy their own commitments in the wholesale market. The development of such a mechanism is feasible since the commercial interests of a ‘high cost’ generator would be served by purchasing ‘lower cost’ generating capacity to meet its own contracted commitments. This would enable the transmitter to call up generators in merit order, allowing for the costs of generation as well as transmission, to meet the demand for electricity within the wholesale market at minimum delivered cost. Under this arrangement, the cost competitiveness of generators would determine their position in the merit order.

A security market covering the grid's contingency reserves and other security requirements to maintain the integrity of the system in terms of its reliability and quality standards would be managed by the grid operator. As currently occurs, reserve/security requirements would be provided by generators and/or distributors and large users. The development of this market would allow the grid operator to meet these requirements at least cost by contracting with generators for reserve supplies of power and/or with distributors and large users for emergency load shedding arrangements. The costs of meeting these requirements would become more transparent and they would be included in the transmission charges of the grid operator.

The wholesale market would facilitate market transactions between the generators and distributors (or large users). Since distributors would not be able to predict their electricity requirements fully and would likely have differing preferences for price ‘stability’ to meet the needs of their customers, they would seek pricing arrangements with generators which reflected their preferences. In essence, distributors would be able to negotiate contracts with generators to cover all or some of their estimated requirements, purchase some of their requirements on a spot basis, and trade in futures to spread the risk of fluctuating prices.

The combined market transactions between generators and distributors, together with those between generators and large users (see below), would determine the quantity of electricity required from the dispatch market. The security market would operate to balance any unexpected fluctuations in demand and/or supply.

The retail market would cover sales between distributors and users. As currently applies, sales could be arranged on a contract or non-contract basis. Contract sales could continue for large industrial and commercial users. These users could specify the nature of the contract they wanted in terms of their preferences for price stability and the like.

Smaller users (including domestic consumers) would pay for electricity on a tariff or non-contract basis.

Generators may well elect to sell directly to users. This currently occurs in the case of large direct sales of electricity by ECNSW to users such as the State Rail Authority and some large industrial customers, such as BHP. With the separation of transmission from generation and distribution, opportunities for direct sales by generators would increase.

Opportunities created by the development of these markets and some pricing options which may emerge are discussed in the study undertaken for the Commission by IES (1990). A summary of the study is provided in Chapter 9.

A number of practical issues arise in relation to the operating requirements for these markets which would need to be resolved prior to the adoption of full separation (notably in the areas of grid functions, pricing arrangements and regulatory provisions). There would clearly have to be a transition period to allow the marketing arrangements to be trialled and refined, and for industry participants to adapt to the new arrangements.

In view of the current organisational arrangements within the ESI and the practical issues raised by full separation, it would be desirable for separation to be introduced in two stages. The first and interim stage would entail notional separation of generation, transmission and distribution through the adoption of ring fencing and preparation for full separation. It is envisaged that this stage might comprise a period of up to two years to provide sufficient time for the resolution of practical issues raised by full separation. The second stage would involve full separation. For each stage, there would be a need for a body with monitoring and regulatory powers to oversee the process of change, ensure compliance with grid guidelines and regulations, and to guard against the use of monopoly power.

7.3.2 Generation

The proposed separation of generation and transmission would allow new generators to compete on equal terms with existing generators for access to the transmission grid.

Following this change, the question arises whether the promotion of greater competition within the generating sector, through the horizontal separation of existing generation facilities, would enhance the performance of this sector. As with transmission, separation also raises the question of whether ownership is best undertaken by public or private bodies. The discussion which follows presumes no ownership changes amongst existing generators. The ownership issue is taken up in Chapter 8.

As the generating sector currently accounts for the bulk of industry costs, its performance substantially influences the performance of the ESI as a whole. In the Commission's judgment, excess capacity, over-staffing and other symptoms of poor performance within this sector (see Chapter 3) have largely reflected a lack of competitive disciplines in generation, with the resulting costs being passed onto users in the form of higher charges, and to taxpayers in the form of lower dividend yields.

Competition for the supply of new generating capacity would provide benefits but, with existing excess capacity, these benefits may be limited over the next 10 years or so. Horizontal separation and greater competition could be accelerated by breaking up existing generating capacity into competing units. This has recently occurred in the United Kingdom and is being considered in New Zealand. This offers the prospect of obtaining larger efficiency gains sooner.

The break-up of existing generation would provide gains in three main areas:

- stronger incentives for cost minimisation;
- pressures for more efficient pricing, with prices being driven towards short-run marginal cost (where excess capacity exists) or the cost of providing additional capacity; and
- access to better information on the comparative performance of generators, enabling the simplification of regulatory and/or monitoring arrangements.

There is, of course, a need to weigh these benefits against the possibility of higher transaction costs with a generation sector characterised by multiple suppliers under separate ownership.

A number of industry participants indicated their support for the promotion of greater competition in generation as a means of improving the efficiency of the industry. For example, the LGEA of New South Wales observed that:

> ... competition in generation affords the best opportunity for further real price reductions.

In its response to the draft report, the SECV stated that it:

> ... agrees with the provision of some horizontal dissaggregation, particularly in the generation area, to introduce genuine competition in addition to national and international price comparisons.

The break-up of generation could take a variety of forms ranging from a separate owner for each power station to a less disaggregated structure based on only a few separate generator groups in each state/territory. In an outline of the Direction of Reforms in the ECNSW (1991), the possibility of separating the current six base-load power stations (seven counting Mt Piper) in New South Wales into three geographically based centresCentral Coast, Hunter Valley and Western - was discussed.

A number of key industry features would influence decisions on the appropriate degree of break-up. These include:

- the availability of scale economies;
- effects on system economies; and

- other factors, such as the cost differentials between power stations.

Scale economies

There are significant economies of scale in generation arising from savings in both operating and capital costs as the size of generating units increases. The optimal sized generating unit will vary depending on the technology involved and system loads. Cost savings can also be attained by grouping individual units into power stations under single ownership. It is widely accepted that four-unit stations are likely to be the most appropriate for economy and management. The size of an ‘optimal’ power station will vary depending on the fuel type used, the load characteristics of the particular system and the existing mix of power stations. All of these factors influence the minimum efficient size of a generating company and the number of potential competitors for a system of given size.

In the Commission's assessment, the realisation of available economies of scale in generation in any state/territory would not be put at risk by having competing generators.

System economies in generation

Another source of cost savings within generation are so-called system economies. Large integrated generation systems have a reduced need for reserves relative to system load, and tend to benefit from greater diversity in load. These economies appear to be available almost indefinitely with increasing system size, although they become marginal in very large systems.

These economies may be attained through horizontal integration of generating units, by having closely coordinated pools of separate firms, or by individual contracts between independent but interconnected utilities. As discussed in Appendix 6, the existing interconnection between New South Wales, Victoria and South Australia has produced significant cost savings and has demonstrated that such savings do not require a single organisation. The discussion of power coordination and pooling arrangements in Appendix 10 also demonstrates that these arrangements are capable of capturing significant system economies within generating sectors characterised by highly diverse structural and ownership features.

Thus, the exploitation of system economies does not require single entity generation. The real issue concerns the relative merits of these different organisational structures, not just in terms of operational matters, but also in relation to their impact on productive and pricing efficiency. Hence, there is a need to consider the efficiency costs of break-up against the benefits. Relevant considerations include the wider operating features of the generating sector in particular states/territories (since they will affect the opportunities for worthwhile competition), the cost differentials between power stations, the sizes of systems, their load characteristics and other features such as the geographical location of units and the presence of shared resources/infrastructure.

Other factors

Information from submissions and other sources provides an incomplete overview of the cost and load characteristics of electricity systems within Australia. In some states (eg New South Wales and Queensland), there appear to be several power stations with relatively small operating cost differentials between them. In consequence, small changes in these costs linked to improvements in fuel, plant and/or labour efficiency could produce changes in the merit order of power stations and in their utilisation and profitability. As a result, there appear to be strong incentives for active competition between competing generators. However, with a generating sector characterised by single ownership of all power stations, there are only limited incentives for managers to capture these efficiency gains.

In discussing the size and load characteristics of its power system relative to those elsewhere in Australia, and the effects of these variables on opportunities for promoting competition, SECWA observed that:

> In NSW, Victoria and Queensland, the electricity market could sustain a number of independent generating firms in competition with each other, using large unit sizes. However, in WA, the relatively small electricity market is unlikely to enable a number of independent generating firms to remain in competition with each other.

According to SECWA, the reason for this was:

> In a market as small as that in WA, with no access to hydro-generation, it is likely that the mix of generating unit sizes of independent firms would be inefficient in terms of reserve margin, spinning reserve and capacity factors. This may lead to the long-run average cost of supply being higher than would be the case under a single generating firm operating all plants.

These claims appear to be inconsistent with the recent decision that the private sector is to build, operate and own the State's next base-load power station. Further, because of the potential savings from the coordination of the system's reserve margin and spinning reserves, there would be strong incentives for co-operative arrangements between generators to capture these savings - the operation of power pools in the United States provides an example of such arrangements.

In its submission on the draft report, the Tasmanian Government indicated that:

> The breaking up of generation into independent competing entities based on river systems is considered impractical due to the inherent differences between individual schemes and the need for centrally co-ordinated operation to derive the full benefits of the existing integrated system.

However, the Nordic system seems to operate effectively with multiple generators along the same river systems. Nordel's 1989 Annual Report observes that:

> The utilisation of hydro-power stations is determined by their owners. It is however common within the Nordic system that stations along the same river can belong to different power companies. This calls for collaboration regarding matters such as how common reservoir capacity should be financed, and how the water shall be regulated both short-term and long-term.

In the case of Tasmania, the Commission considers that scope may exist for promoting competition in generation by creating separate generating entities for the different river systems supplying the State's electricity.

The Northern Territory Government also commented on this issue, noting that:

> Electricity supply systems in the Northern Territory are very different to those which operate in the States and ACT. PAWA is required to serve small communities at localities remote from both major service centres and from each other and, where economically feasible to do so, major mining and pastoral centres.

and further, that for this reason:

> … one of the options that may be available to the States of lowering unit costs by creating competition is simply not available to the Territory as any fragmentation of the market would increase average costs rather than decrease them.

At present, PAWA's system consists of mainly gas-fired stations which supply the Territory's main towns and around 60 isolated diesel power stations located in remote communities. While the scope for dividing generation in the Northern Territory is limited, there could be merit in splitting the interconnected system from the smaller generating units serving remote areas which could, in turn, be divided into a number of regional groups. This would facilitate comparisons of performance.

In general terms, the main efficiency costs of breaking up generation would seem to be:

- higher costs in system coordination and planning given a larger number of independent suppliers;
- higher costs for fuel and capital equipment arising from separate aquisition/smaller orders and higher inventory levels; and
- the somewhat uncertain effects of competing units on the incidence of excess capacity and investment coordination.

The Commission is unable to assess the significance of these costs, given an absence of the necessary data and the difficulty in judging future efficiency gains available from a structure where groups of generators compete to supply electricity. Much of the necessary information is, however, available to existing utilities. Indeed, the principle of having separate and independent generators has been accepted in a number of states. For example, ECNSW is in the process of separating its major base load power stations into regional groups to ‘allow stations to compete internally to supply power to the transmission grid’. SECWA's next base load power station is to be privately built, owned and operated. The SECV has also supported the idea of independent operators in the generation area to promote genuine competition. It is also advocating the sale of one of its major power stations.

Provision of electricity to a market by a number of independent firms is not radical. It happens in many other countries such as Belgium, Denmark, Germany, Japan, the Netherlands, Norway, Sweden, the United Kingdom and the United States.

The Commission judges that there are likely to be significant benefits from a limited breakup of existing generation into a number of independent generating bodies. As with transmission, movement to this revised structure could be accomplished by initially notionally separating (ie ring fencing) generation facilities into separate units. Full separation or breakup could then be introduced to coincide with this change for the transmission grid.

7.3.3 Distribution

The preceding discussion has addressed the need to separate transmission from generation and distribution, and the desirability of promoting competition in generation through a limited break-up of existing generators into a number of independent generating bodies. The separation of distribution from transmission and the question of whether there should be single or multiple distributors of electricity are examined below.

Separation or integration

The case for separating distribution from transmission centres on two main considerations. First, separation would allow generators and distributors to engage in direct exchanges of electricity which would impose competitive disciplines on the transmission network and generators alike. Second, the separation of distribution from transmission is a pre-condition to facilitating competition in distribution through the creation of multiple distributors in each state.

The benefits of separation need to be balanced against the cost of putting at risk any economies from the integration of transmission and distribution. Given the nature of these functions, it is difficult to identify many such economies, other than those of corporate management, and some areas of equipment purchases. However, because transmission generally involves different staff and equipment from distribution in most areas, neither seems likely to be significant. While the separation of distribution would increase the commercial risks facing existing generators in competing for sales to the distributor, these risks normally face any wholesaler. Moreover, they are vital in creating incentives for production and pricing efficiency on the part of generators.

In order to promote more effective competition in the ESI, it would also be desirable to require that distributors provide open access to their networks. Coupled with the removal of exclusive franchises, this would increase the scope for competition in two new areas - border and by-pass competition.

Border competition refers to competition near the borders of distribution areas. By-pass competition occurs where major users are free to negotiate supply with generators/distributors without the impediment of an exclusive franchise on sales in a particular distribution area. The addition of an open access requirement on distributors would enhance the competitive pressures arising from such competition. In these circumstances, it may be profitable for a user to by-pass an existing network and connect either directly with the transmission grid or to a generator. It may also cover situations where the by-pass is to the distribution network in another state/territory. Such by-passes would have to meet connection and technical standards set by the distributor or transmitter where they connect into their network.

In the Commission's view, distribution should be separated from transmission and generation where this does not currently apply and distributors should be required to provide open access to their networks. The two stage process recommended for the other industry segments - involving a period of ring fencing to help resolve transitional problems followed later by full separation - could be applied also to distribution.

Regulatory provisions

The Commission considers that the distribution function should be subject to much the same regulatory provisions as those it is proposing for the transmission grid. Hence, there should be a requirement for guidelines and regulatory oversight relating to access conditions and pricing (including wheeling charges) in the event of user by-pass and/or direct exchange of electricity between generators and distributors, as well as published guidelines relating to charging practices. In respect of the latter, distributors should be required to distinguish clearly between the transmission charge paid to the transmitter, the fixed charge for access to the distribution system and the variable charge for electricity consumed. During the transition to full separation,there would be a need for regulatory oversight relating to the development of open access conditions, wheeling charges and the connection and technical standards required in the event of by-pass arrangements.

As noted in relation to transmission, with full separation of distribution and an accompanying open access requirement, it may be sufficient to rely on the general provisions exercised by the TPC and the PSA (with the possibility of some rationalisation of functions between the two bodies) to encourage appropriate behaviour by distributors in affording access to the distribution network and charging for such access. If this approach were shown to be ineffective, industry specific monitoring (including the possibility of a price capping arrangement) could be introduced.

Single or multiple distributors

A further question relating to the distribution sector, raised in the inquiry's terms of reference, is whether distribution is more appropriately performed by a central authority or by a large number of distributors.

The Commission invited comments on this question in its Issues Paper. Utilities' views were consistent with their views on other aspects of structural change: they overwhelmingly rejected the notion of significant change and supported the current structure in their state/territory, even though there is considerable diversity in the way in which distribution is currently handled in Australia. For example, the LGEA of New South Wales argued that the decentralised retailing structure comprising 25 local government councils in New South Wales was preferable to the alternative of a single retailing authority for the State because it:

> ... inherently minimises inappropriate cross-subsidies, maximises competition and provides greater scope for improved management and local community input, while still affording opportunities for co-operation to achieve economies of scale.

In contrast, SEWCA supported the retention of a state-wide distribution system. It observed that:

> Regionalisation of the distribution system, in a similar framework to that existing in NSW, would result in significantly higher electricity prices for non-metropolitan customers, particularly those in rural areas on the fringe of the distribution system. Costs are higher in these areas due to increased line losses, lower utilisation of the distribution system and increased amount of distribution system per customer.

and, further, that an additional disadvantage of a regional or decentralised system was that:

> ... economies of scale in administration of accounts, meter reading and maintenance would not be available.

These contrasting views identify the main issues relating to the perceived merits of the alternative approaches to organising the distribution of electricity, namely, their implications for:

- the attainment of equity and regional development goals;
- the realisation of available economies of scale; and
- the extent of competition in the marketing of electricity to users.

While acknowledging that electricity supplies are perceived by some as an essential service and that governments may seek to promote regional development through uniform pricing policies, the Commission considers that neither objective requires a single distribution authority within a state or territory. Indeed, SEC WA indicated that:

> It is possible that the equity and development aspects of the regionalisation of the electricity distribution system could be addressed in an alternative manner. For example, a regional distribution authority could be subsidised by the State Government. Alternatively, the local government authorities adversely affected could be given compensation directly by the State Government.

Economies of scale are likely to arise from the technical and organisational characteristics of electricity distribution. On the technical side, economies are likely to arise from cost savings on lines and transformers within larger systems. At an organisational level, there are likely to be economies in administration, meter reading, information systems, use of specialist staff, marketing and input purchases with increases in firm size. Thus, SECV's strategy is to apply strong competitive pressures to its distribution business centres, while retaining the economies of scale of a common corporation. However, as noted by the Queensland Government, it is also likely that diseconomies, linked to higher costs of controlling and managing resources, will emerge if distributors become too large.

The Commission has been unable to identify any studies of economies of scale for the distribution sector of the Australian industry. However, a number of studies have been undertaken in New Zealand and the United States which may provide some guidance in assessing future arrangements for Australia.

For New Zealand, Giles and Wyatt (1989) identified major cost savings in moving from 60 distribution authorities to between 30 and 40. Additional cost advantages arising from moving to around 8 to 9 - the most efficient number identified in the study - were very small. A number of studies in the United States have also identified economies of scale in electricity distribution. They tend to report economies of scale up to the size of a small city, by United States standards, and record potential diseconomies of scale above this level.

A further consideration in judging the implications of economies of scale for the appropriate organisational form for electricity distribution is whether some of the available economies can be captured through co-operation between distributors. According to the LGEA, many of the benefits of economies of scale are currently being captured by the distribution councils in New South Wales through co-operation in areas such as joint marketing, staff training, group purchasing and joint management of inventories. Indeed, SECV and GFCV co-operate to reduce the cost of electricity and gas meter reading. This suggests that the existence of multiple distributors need not compromise the realisation of economies of scale.

Nevertheless, it is possible to have an excessively fragmented distribution structure. In New South Wales, there were over 150 county councils distributing electricity in the 1940s - this level being progressively reduced to 40 in 1978 and 25 at present. Under the current structure, the four urban councils account for some 80 per cent of total retail sales - Sydney Electricity, formerly Sydney City Council (44 per cent), Prospect Electricity (19 per cent), Shortland Council (9 per cent) and Illawarra Council (7 per cent). The remaining 20 per cent is handled by 21 rural councils. In view of the small size of many of these councils, there could be efficiency gains from adopting a regionalised approach along the lines of that applying in Queensland.

Within Victoria, there would also appear to be an excessive level of fragmentation with 11 municipal electricity undertakings handling 20 per cent of the State's electricity sales for a densely settled part of the network. The SECV handles the remainder, which includes the retailing of electricity to all the non-metropolitan areas of the State.

A study by the Victorian Grants Commission (1989) found that operating costs for MEUs were greater than that for SEC V's distribution operations under similar conditions. Although it did not address in detail the issue of economies of scale, it suggests there would be some benefit in amalgamating some of the MEUs.

While it is not possible to be prescriptive, economies of scale considerations provide few grounds for having a single distributor on a state-wide basis. Further, there could be excessive fragmentation of distribution in parts of Melbourne and non-metropolitan New South Wales. In contrast, distribution in urban New South Wales could perhaps be too centralised.

A major issue bearing on the structure of distribution activity is the level of competition in the marketing of electricity.

According to the LGEA of New South Wales:

> ... the NSW system permits, and indeed encourages, competition between areas.
>
> Councils actively compete with each other, and with interstate authorities, to attract commercial and industrial customers. In addition, recently introduced Performance Agreements provide an environment in which individual councils are encouraged to be seen to be doing better. All councils are jealous of their reputations as competent Managers of their areas.

In contrast, the centralised distribution authority operating in most state/territories faces no competition within its state/territory. Moreover, there is less information with which to compare and assess the efficiency of these single distributors. Where multiple distributors exist, key operating and financial data can be more readily drawn on to assess performance. This provides an opportunity for the development of ‘yardstick competition’. The same information would aid the development of improved performance monitoring mechanisms and facilitate the design and operation of more effective regulatory provisions. An additional competitive discipline would be tendering for the right to service a particular distribution area, along the lines of that discussed for gas utilities in Chapter 6. The SECV has indicated that, after it has rationalised a number of its District Business Centres to create somewhat larger units, it will consider a trial involving the separate franchising of the management of some of these distribution areas.

The Commission concludes that there is merit in dividing distribution responsibility between separate entities in those states with a centralised or largely centralised distribution authority,

namely Victoria, South Australia, Western Australia and Tasmania - and that consideration should be given to doing so elsewhere where there is a large distributor (eg in urban New South Wales). Such break-ups could be structured around existing regionalised divisions, but should not be constrained by state boundaries. The amalgamation of a number of the smaller distribution entities operating in the non-metropolitan areas of New South Wales and in Melbourne is also worthy of consideration.

As with transmission and generation, these changes could be introduced in two stages to help identify and resolve transitional problems. Following studies to determine the appropriate number of distribution units, proposed distribution units could be ring fenced Subsequently, the restructured and corporatised versions of these units would be subject to full separation.

7.3.4 Integrating the south-eastern Australian network

Improved use of existing interconnections and a more commercialised approach to extending or upgrading these interconnections offers a means of realising greater benefits from the SE Australian electricity system. The present operation of this system and the net benefits arising from interconnections are discussed in Appendix 6.

Until recently, individual electricity utilities within this system have largely sought to balance their own generation and loads internally, and have relied on interconnections between networks to share reserves and for short-term economy exchanges of electricity. Consequently, the potentially greater benefits associated with longer term exchanges directed at acquiring electricity from the lowest cost sources having regard to all supply options - irrespective of location - have not been adequately addressed. Further benefits could be derived from coordinating investment to defer expenditures and to improve plant mix to handle intermediate and peaking requirements at lower cost. This would require a more market oriented approach to the use of gas (including greater interstate transfers where commercially attractive) as a fuel source within this system.

The need for decisions on new generating capacity within the next two to three years and the possibility of enlarging the existing system to encompass Tasmania and Queensland during the 1990s pose further challenges for the operation and management of the system. According to the New South Wales Government, the current system has not been adequately used because:

> *Traditionally the generation and distribution of electricity has been viewed parochially as an operation specific to each State. If economies of scale and resource conservation are to be achieved there needs to be a total geographical approach applied to the industry.*

In their submissions to this inquiry, the ESAA, together with each of the states involved in the existing SE Australian network, recognised the benefits of adopting a more market oriented approach. In its initial submission, the SECV listed the benefits as follows:

It would maxamise the level of competition in the provision of new generation by increasing the number of options;

- The best use of resources can be achieved by selecting the minimum total cost option irrespective of State boundaries;
- The reserve plant margin required for the total system will be reduced; and
- The transmission links developed will provide long term benefits for the system.

In its draft report submission, the SECV indicated how a more effectively operated system would benefit Victoria and the other states in the following terms:

> In addition to the previously restricted range of options available, the next, say 500 MW increment of capacity required in Victoria could be potentially satisfied by hydro, black coal or gas central generation or cogeneration options or conservation initiatives in other States. The widened range of economic and environmental impact options will create opportunities for the more optimal use of resources in all States.

The views of industry participants and users point to an increasing recognition that the attainment of these benefits will require the SE Australian grid system to be operated as a whole rather than incidentally to the individual networks comprising the system. This raises the issue of what key organisational arrangements are required to maximise the potential benefits.

This issue is currently being addressed by the Electricity Working Group established by the Special Premiers' Conference in October 1990. The Working Group is to report to the next Conference.

A variety of organisational models could be used to operate and plan the SE Australian grid including:

- A modified version of the existing co-operative management committee; and
- A separate national grid entity.

A modified version of the existing arrangement

At the draft report hearing, the ESAA and SECV supported the establishment of a 'national grid' (really a Southern and Eastern States Grid). Both proposed a modified version of the existing co-operative management arrangement based on the Nordel model in Scandinavia as the most appropriate basis for grid management.[1]

[1] Nordel is an organisation for co-operation formed in 1963 between electric power companies in the Nordic countries of Denmark, Finland, Iceland, Norway and Sweden. It is governed by mutually agreed recommendations and principles and is directly managed by the participating electric power companies without the need for directives or control by any superior body. There is no overall Nordic operations management. However, Vattenfall (the Swedish operating control unit) has a co-ordinating responsibility for frequency control and demands on operating reserves. The individual national operation managements are otherwise responsible for the operations management of the Nordel system.

Under this arrangement, ownership and operation of generating, transmission and (where relevant) distribution assets in each state would be retained by the respective state utility. The operation of the ‘national grid’ would be undertaken on a co-operative basis through a National Grid Management Council. The Council would develop principles and make recommendations of an advisory nature about the operation and planning of the grid system. Membership of the Council would comprise the members of the existing interconnection management committee (the Chief Executive Officers of ECNSW, SECV and ETSA) and, in anticipation of prospective interconnections, the Chief Executive Officers of QEC and HECT.

According to the SECV, the Council would have responsibility to:

1. establish a PROTOCOL defining the conditions and terms (including the charging framework) for access to the GRID for both utility and private generation and bulk supply customers (the terms and conditions for access to the GRID shall be the same for both utility and private generators);

2. develop and implement detailed operating arrangements for operation of the generation and main transmission systems;

3. co-ordinate the planning, design and development of transmission system and associated works for the interconnections between the State Grid utilities including control systems, protection systems and associated works;

4. develop and implement procedures for research, development and technical co-operation;

5. develop and implement commercial, environmental and social evaluation criteria for new supply and demand side options and development of the GRID;

6. co-ordinate planning of generation and interconnection capacity additions;

7. monitor and publicly report on the performance of the GRID and the Electricity Supply Industry; and

8. report each year to Heads of Government on matters relating to the responsibilities of the Council.

The ESAA and SECV claim that this proposal has the advantage of not requiring any changes to the existing legislative and regulatory framework for the industry in these states. The proposal also requires no structural changes to the ESI. Consequently it could be developed relatively quickly.

However, in the Commission's view, it is the structural, legislative and regulatory framework which has retarded the development of an integrated grid in SE Australia. To propose an alternative arrangement without changing these areas would perpetuate many inefficiencies. It is an option which could be characterised as ‘more of the same’. Based on past criticisms of the co-operative joint management model for enhancing cooperation and advancing a national perspective (see for example, McDonell 1986 and NERC 1988), and the limited modifications evident in the ESAA and SECV proposal directed at addressing these criticisms, the Commission considers such an arrangement to be inadequate for the task. It could effectively enshrine shortcomings which have dogged the existing interconnection arrangements for years.

Major weaknesses include:

- the failure to separate transmission from generation and distribution;
- the lack of a national perspective;
- the limited membership of the proposed Council; and
- inadequate accountability.

No separation of transmission from generation and distribution

The achievement of the potential benefits from the existing (and possibly expanded) interconnected grid will depend crucially on the development and implementation of more effective operational, planning, access and pricing arrangements. This will require impartial consideration of alternative proposals. However, if as proposed by the ESAA, the new arrangements are developed and transmission facilities are operated by the existing utilities - each of which is also responsible for generation and, in some cases, for distribution as well - conflicts of interest are inevitable. Hence, the likelihood of achieving unbiased assessment and operating procedures will be significantly reduced.

Evidence that such outcomes may eventuate can be found in the current ESAA/SECV proposal. For example, as outlined to the Commission, there is only comparatively weak provision - through a grid agreement or protocol developed by the utilities themselves - for protecting the interests of new generating entrants and/or large bulk users. The existing utilities would be able to continue to protect their own operating preferences, inefficiencies and monopoly powers in generation and distribution. There is no balancing role played by independent distributors, other large customers or independent generating bodies. If these existing interests in the industry are given no effective role, potential competing entrants - such as independent generating firms - would be poorly situated. Thus, one avenue for increasing competition in the industry could effectively be closed off.

No national perspective

The proposed arrangement would preserve the established tendency for state-based interests to dominate wider grid interests, thereby limiting wider benefits available from more fully co-ordinating the operation and planning of the system in areas such as the scheduling of capacity extensions, improving the mix of generating capacity and improving fuel sourcing decisions. The SECV commented that the approach:

> ... provides a significant voice for individual states (who alone in Australia have expertise in Grid planning and operation) in the future of the Electricity Supply Industries in Australia ...

Under the proposed arrangement, each state would be free to decide how much, if any, electricity it buys and sells interstate and how much, and on what basis, it purchases from private generators/cogenerators. State utilities could readily continue to service virtually all areas of their own state, rather than permit demand to be satisfied from interstate. The incentives for governments/utilities to pursue parochial interests rather than to adopt a national perspective would remain in place.

With ownership fragmented between five states and the Commonwealth, the probability of government interference would be far greater than if ownership were vested in the one body. Additionally, to the extent that the proposed Council mirrors the existing committee and has no executive power, proposed actions could be delayed by protracted discussion, as has happened in the past. Larger utilities could dominate smaller utilities - or impose an effective veto over proposals which do not advantage them.

Membership of the Council

The membership of the Council envisaged by the SECV would not be fully representative. New South Wales distribution utilities would have no voice; nor would other independent distributors (eg ACIEW) and private bulk electricity purchasers. There is no provision for Commonwealth representation, despite the significance of the Snowy Scheme and the importance of the grid from the national perspective. Furthermore, it is difficult to see how existing utilities could properly represent the interests of new entrants. The lack of a representative council reinforces the structural weaknesses inherent in the proposal.

Accountability

In response to the draft report, the SECV stated that:

> The Council is a co-operative management arrangement, ie directly managed by the State grid utilities ... without the need for directives or control by any superior body.

This arrangement amounts to self-regulation by the existing players. The proposal encompasses only limited provision for accountability through public reporting on the activities and policies of the Council and an annual reporting requirement to Heads of Government. However, it is not clear that the current arrangements surrounding the Special Premiers' Conference are to be on-going. The question then arises as to whom the Council would be accountable? In the absence of greater accountability and more rigorous monitoring of the grid's operations and policies, it is improbable that competitive pressures within generation and distribution could be effectively developed.

A separate national grid entity

To avoid the short-comings of the ESAA/SECV proposals, the Commission prefers an arrangement involving a single public entity, functioning independently from generation and distribution activities and subject to regulatory oversight. This entity would have responsibility for coordination and development of the grid. These responsibilities could encompass most of those outlined earlier for the ESAA/SECV proposal, but would recognise the independence of generators. The new body would be accountable to a Council of Ministers representing the participating governments.

Following the separation of generation and distribution from the existing transmission network, the new organisation would own and operate the main transmission systems. This arrangement is essential if the transmission system is to be operated so as to minimise supply costs and to ensure that future developments reflect national rather than individual states' interests. This would not preclude the development of new transmission lines which private interests may wish to construct (eg to connect a new power station to the interstate grid).

The main coordinating/planning responsibilities would cover operating procedures to optimise the day-to-day performance of the system and planning studies to meet changing demands on the transmission system in an optimum way. Published policies covering competitive bidding for new increments of generating and transmission capacity, access conditions and pricing (including wheeling) would also be required.

Given the central importance of these policies to the performance of the system, there would be a need for independent regulatory oversight of the arrangement. In the first instance, the regulatory task would involve procedures for the formal oversighting and approval of the development of operating, competitive bidding, access, pricing and planning provisions. This would need to be undertaken by an independent body. This could be achieved by requesting (by means of a Ministerial Direction) that the TPC fulfil this role. Its primary objectives would be to promote transparency and competition. In this regard, its functions could include a requirement to release draft proposals of new arrangements for public comment.

The development of the new arrangements could be the responsibility of a Steering Committee comprising representatives of participating governments, rather than of utilities. The present interstate interconnection management committee, expanded to include representatives of QEC, HECT and SMHEA, could assist the Steering Committee in developing these arrangements and assessing studies into the feasibility of connecting Queensland and Tasmania. During the transitionary period prior to the formation of the new national transmission body, the Steering Committee could also take responsibility for assessing requirements for new generating capacity.

Once the new arrangements are in place, the regulatory task would entail monitoring the arrangement to ensure adherence to approved procedures and any extensions to these procedures. The separation of transmission from generation and distribution would significantly simplify the regulatory task by promoting open and non-discriminatory access to the grid system. In these circumstances, the activities of the transmitter and the other industry sectors could be subject only to the general monitoring provisions of the TPC and the PSA, perhaps with the modifications to rationalise the activities of the two bodies suggested for consideration in Section 7.3.1.

The participants in this separate interstate transmission grid would be the governments represented in the existing interconnected system (ie the Commonwealth, New South Wales, Victoria and South Australia), together with Queensland and Tasmania, reflecting the possibility of their interconnection at a later stage and the desirability of planning accordingly. Initial shares in this SE Australian transmission grid entity would reflect the value of each government's contribution to the new transmission grid. Provision could be made for participants to sell their shares in the grid. The Commonwealth might consider acquiring a larger equity in the grid to increase the likelihood of a national network being operated more effectively as an interconnected system.

Under the new arrangements, generators would compete for access to the grid (including possible interstate transfers) on the basis of their competitiveness in supplying electricity. Generators with access to the grid would include the restructured versions of the existing supply authorities in each state, as well as any independent generators or cogenerators.

At the draft report hearings, the ESAA likened this proposal to an unwieldy bureaucracy which would deliver a less effective service to customers than either the present arrangements or its own proposal as discussed above. It further claimed that:

> The creation of a single body for transmission will also reduce the competitive forces in that segment of the industry by reducing the opportunity for comparisons of the commercial performance of independent state grids.

The Commission can see no reason why a national grid entity would be ‘unwieldy’. It would certainly be far smaller than most of the existing vertically integrated state utilities which the industry wishes to maintain. In the Commission's view, a single transmission grid entity would enhance the operational, coordinating and planning functions by reducing fragmentation of decision making processes and by better promoting a national perspective. The new entity would result in the replacement of the existing monolithic organisations by a smaller entity operating in a more competitive environment. This should promote a more effective service to customers.

The Commission acknowledges that the creation of a single transmission grid entity would reduce opportunities for yardstick competition for the transmission function. But such benefits are likely to be miniscule compared with those which could eventuate from the development of real competitive pressures in other parts of the ESI where most of the costs lie. Importantly, these benefits largely hinge on the separation of transmission from other industry functions.

The Commission concludes that a separate national grid organisation (with the features outlined above) would best promote the effective coordination of the operation and development of the SE Australian grid. The establishment of this organisation would involve two distinct stages. The first stage would cover the ring fencing of generation, transmission and distribution within the SE Australian grid network This stage might cover a period of up to 2 years, during which a Steering Committee could establish the necessary operating procedures and policies for the grid entity. This could be oversighted by the TPC if it were given a special brief (by means of a Ministerial Direction). The primary objectives of the monitoring agency would be to ensure that the guidelines and procedures established will promote transparency and competition in the industry. The second stage would involve the formal establishment of a fully separated grid organisation accountable to a Council of Ministers. Its activities would be subject to the general provisions of the TPC and the PSA, perhaps with the modifications outlined in Section 7.3.1.

Mainly because of the large distances involved, interconnection of Western Australia and the Northern Territory to the SE Australian grid is not envisaged in the forseeable future.

7.4 Promoting competition in the natural gas industry

Like electricity, the NGI is, in general, characterised by limited competition. The main competitive disciplines are:

- Pressures arising from competition between natural gas and other forms of energy (such as electricity, fuel oil, LPG and solid fuels);
- In the case of private gas utilities, exposure to the disciplines of the capital market, sharemarket, market for managers and the ultimate discipline of insolvency;
- The use of contracting out as an alternative to ‘in house’ provision of certain goods and services;
- Competition between states (and in some cases within states) for the supply of gas on competitive terms to new industries and/or existing industries considering an expansion of their activities (eg fertiliser manufacturing); and
- The use of competitive tendering processes to assess the most appropriate supplier at the time existing networks are being extended.

The corporatisation reforms outlined in Chapter 5 will extend some of these areas of competition and promote fairer competition between natural gas and electricity by, amongst other things, exposing public electricity utilities to the same government taxes and charges as those applying to private gas utilities, the discipline of earning a commercial return on investments and requiring electricity utilities to meet the full costs of their borrowings. However, the structure and stage of development of the natural gas industry in Australia are such that there would continue to be limited competitive pressures on suppliers of transmission and distribution services.

The lack of competition reflects the natural monopoly characteristics of transmission and distribution, the dedicated nature of existing supply systems, and the limited extent of interstate trade in natural gas. This latter feature is a result of the highly dispersed nature of gas fields relative to available markets and the high costs of connection, together with institutional factors which have constrained, and continue to constrain, gas trading between states. Vertical integration between transmission and distribution in some states (eg Victoria and Western Australia) and contractual arrangements between these industry segments in other states also limit opportunities for competition. As a result, the natural gas market is relatively 'thin', with a single seller facing a single buyer in most states/territories.

The discussion in Chapter 6 suggested that removing institutional barriers to interstate trade in gas could encourage greater exploration which, if successful, would expand not only gas reserves but also the existing supply sources for particular markets. In the short to medium term, this could be particularly important for states such as South Australia and New South Wales where proven supplies are limited. The removal of exclusive franchise arrangements, restricting franchise terms to about 10-15 years and the introduction of competitive tendering for franchising as outlined in Chapter 6 would also lead to some increase in pressures to operate efficiently. Nevertheless, competitive pressures would still be relatively small compared to these experienced by most other industries.

Given these considerations, the question arises whether it is feasible to promote more effective competition within the NGI. This raises three main issues: the appropriate form of carriage for transmission and distribution; whether transmission and distribution should be integrated or separated; and whether distribution within a state/territory should be handled by one or several entities.

7.4.1 The form of carriage

The transmission and distribution of gas by pipeline can operate under four broad arrangements: private, contract, common carriage or open access. Each of these arrangements can lead to different levels of competition and efficiency.

Private carriage occurs when the transmitter owns the gas. The gas may be used by the transporter, sold directly to end users or sold to a third party for resale. Transmission in Victoria, Western Australia and South Australia is by private carriage, as is most gas distribution in Australia.

Contract carriage occurs where the pipeline owner enters into an agreement with the owner of the gas to transport it. Under this form of carriage, the pipeline owner is able to refuse to carry gas for another party. The carriage of most gas between South Australia and New South Wales is done under a contract between TPA and AGL, although the TPA is able to carry gas for other parties under certain conditions. Some gas is also transmitted under contract by GFCV for the SECV and Esso/BHP.

On the other hand, a pipeline operating as a common carrier is required by law to transport the gas of any party requesting the service. Depending on the nature of the requirement, this could require the pipeline operator to increase the capacity of the pipeline. This can give rise to problems concerning how the costs of extensions should be allocated. To help ensure that the common carrier provision operates effectively there is usually a need for service levels and carriage fees to be regulated.

In discussing the situation in Queensland, where a common carriage requirement formally applies to the Roma to Brisbane pipeline, AGL Petroleum claimed that:

> The concept of common carriage is inappropriate for gas transmission pipelines given its vagueness ...

and further that if:

> ... some form of regulation of the price of gas transmission pipeline services is seen to be necessary, the regulatory criteria should be clearly defined.

Reflecting these concerns, a number of gas industry representatives indicated that it was not necessary to apply a strict common carrier provision to promote access to gas pipelines on non-discriminatory terms. A less cumbersome form of carriage capable of securing a similar outcome is often characterised as ‘open access’. Under this form of carriage, access can be extended to third parties on terms mutually agreed between the pipeline operator and the prospective user, subject to regulatory oversight to ensure non-discriminatory behaviour by the pipeline operator. If there is no available capacity, carriage can be denied.

Within Australia, private carriage is prevalent because gas distributors have seen merit in vertically integrating their activities with gas transmission. This allows the distribution utility to reduce some of its operating risks. It also enhances monopoly/monopsony powers which can be used to boost profits or to balance the monopoly powers of others. Thus, the operation of a private carrier pipeline may sometimes be a deliberate strategy to acquire greater security of supply and to shield the distribution part of the business from competition from other distributors or from direct sales between gas producers and large users. For example, a private carrier would be unlikely to agree to carry another party's gas (ie to act as a contract carrier) if, as a result, the overall profitability of its operations was reduced. Vertical integration also avoids the possibility that an independent pipeline owner will exploit market power to the detriment of distribution utilities.

The potential for the owner of a transmission pipeline or distribution network to use its monopoly power suggests that competition may be enhanced by an open access requirement. This would offer potential gas producers the prospect that, if pipeline capacity is available, gas can be delivered to a market. It would also allow competition in the sale of natural gas, by permitting gas buyers and sellers to trade directly, and not through a third party (the pipeline owner or the gas distributor).

Several gas industry operators questioned the capacity of an open access (or common carrier) requirement to increase competition within the Australian NGI. For example, GFCV claimed that:

> The wide geographical dispersal of supply areas would mean that only in certain limited ... areas would there be conditions where the production and transmission costs were such that real competition could take place between one producer and another.

The introduction of an open access requirement in cases where there is only a single supplier may not produce a lower average cost of gas from a pipeline or network. Reductions achieved by some purchasers may tend to be offset by increases for those unable to exercise a similar degree of market power (ie small users). However, even if this were the case, it is likely that the price paid for gas would more accurately reflect its value in use.

In the Commission's view, an open access provision with regulatory arrangements similar to those canvassed for the transmission of electricity (see Section 7.3.1) should be applied to gas pipelines. It would also be desirable to develop guidelines for new gas transport contracts and apply guidelines/regulations governing terms and conditions of access to the pipeline, as well as procedures for the resolution of any disputes.

The Commission supports the use of open access as a mechanism for increasing competitive pressures on suppliers of transmission and distribution services in the natural gas industry. Regulations aimed at clearly specifying the responsibilities of an open access carrier would be desirable to promote its effective application and avoid any ambiguities relating to its effects.

Whether efficiency gains can be realised from such a requirement will be influenced by the nature of the market for natural gas. Relevant factors include the current number of gas producers and existing restrictions posed by contracts between gas buyers and sellers or transmitters. Due to the relative immaturity of the Australian gas market, it may be some time before the full benefits could be realised.

This outcome is not peculiar to Australia. As reported in Appendix 9, third party access provisions introduced for the British Gas Corporation transmission network in 1982 have been little used because British Gas purchased all existing field-gate gas under long term contracts prior to its privatisation. However, it is expected that new gas discoveries and changes to the pricing and acquisition policies of the now privatised British Gas will tend to increase the potential for competition over time.

In order to gain more immediate benefits from competition, the United States has recently changed regulations governing the operation of pipelines in an attempt to strengthen competition. The changes, outlined in Appendix 9, include options to buy out onerous take-or-pay contracts with producers.

If larger and more immediate gains were desired, the introduction of open access in Australia would also require an examination of existing upstream and downstream regulation and market arrangements, such as long term contracts, which may constrain competition under this form of carriage. If this was to occur, it may be necessary to facilitate the re-negotiation of long term contracts using phasing arrangements similar to those applied in the United States.

A number of companies expressed concern about the effects of requiring the renegotiation of long term contracts to achieve improved access. For example, Shell stated that:

... if a government were to overturn existing long term agreements, this would reduce the confidence of future industry participants in the resilence of any long term agreements they may seek to negotiate, and could deter investment.

GFCV emphasised the importance of such contracts in the following terms:

> The relatively small Australian demand base, in many cases situated at vast distances from the major potential sources of supply, means that large risk capital is to be secured by supply to only a small number of potential large contract users. No transmitter would risk investment unless specific customers were secured through long term take or pay contracts.

The Commission recognises these concerns and judges that it would be counter-productive for governments to seek to force changes to existing contractual arrangements to support the introduction of an open access requirement.

7.4.2 Transmission and distribution - Integration or separation?

Natural gas transmission and distribution are organised differently across Australia. In contrast to electricity, the dominant 'model' for natural gas is for these functions to be handled by separate and independent enterprises. This situation applies in Queensland, New South Wales, South Australia, the Northern Territory and the Australian Capital Territory. In Western Australia and Victoria, these functions are integrated in a single publicly owned enterprise - SECWA and GFCV respectively - although the Western Australian Government is considering a number of expressions of interest from the private sector to acquire the Dampier to Perth transmission pipeline.

As with electricity, the main argument favouring the separation of these functions is to support the development of effective competition by promoting equal access to the transport services provided by the network for alternative suppliers of gas, as well as by distributors and large users. Separation, by ring fencing and ultimately by full separation, coupled with an open access requirement, enhances opportunities for competition in the distribution sector (see Section 7.3.1). Such competition provides three main benefits - pressure for greater productive efficiency, increased likelihood of efficient cost-related pricing and better information for cost-effective regulation.

Without full separation, the existing suppliers of transport services - the pipeline operators - could impede entry by potential rivals through discriminatory pricing and trading activities. Even where an integrated transmitter-distributor is required to provide separate financial information on these activities, considerable scope would remain for discriminatory pricing to deter entry. Further, through control of the existing transmission and distribution network, an integrated operator would have a strategic advantage over any potential rival suppliers of gas since it would in effect acquire advance notice of potential competition. Consequently, the scope for greater competition in gas supply, even with the introduction of an open access provision, is likely to be impaired.

The potential benefits from any improved efficiencies in pricing or production induced by greater competition in a less integrated industry need to be weighed against the potential reduction in internal efficiency from such a structure.

Information provided to the Commission by the GFCV and SECWA in relation to this trade-off was very general. For example, GFCV simply stated that:

> The integration of transmission with other activities leads to lower costs and increased operating benefits, as demand and transmission capacity can be more effectively matched.

It further indicated in relation to a question covering the possible costs of separation that:

> Design, operating and installation overheads would be duplicated.

In response to the draft report, a number of gas utilities (eg AGL, Sagasco and Allgas), indicated that the full separation of future transmission and distribution would limit the development of the industry by placing unwarranted constraints on the number of potential players which could participate in new developments.

The Commission has been unable to identify any Australian or overseas studies which have examined this matter in detail. While integration offers the prospect of economies, the extent of these economies is not clear. However, the coordination task involved in matching supply with demand is far less onerous for gas than for electricity since it is possible to store gas to accommodate unexpected shifts in demand or supply. Furthermore, to the extent that there are economies associated with integration, for example, in the purchase of gas, there are alternative ways (such as contracting and cooperative arrangements) to capture them.

The Commission supports full separation of gas transmission from gas distribution as it considers the ensuing efficiency gains are likely to outweigh the benefits of retaining an *integrated structure. Given the practical issues raised by full separation (eg the functions of the transmitter and pricing arrangements), separation of the activities of GFCV and SECWA should be introduced in two stages. The first stage would involve ring fencing of transmission and distribution along the lines of that proposed for the ESI. The second stage would cover the full separation of these functions.*

As noted earlier, SECWA and GFCV are vertically integrated public entities. A number of private operators, such as AGL, are involved in limited transmission activities, in addition to their core distribution activities. In such cases, the Commission considers that there would be little gain in moving from ring fencing to full separation. Insisting on full separation where involvement in transmission is minor (such as a branch link for the main transmission pipeline), could inhibit the expansion of the gas network for no apparent gain.

While gas production is not included in the reference, the question arises as to whether there should be any limitations placed on integration between gas production and transmission. No utilities in Australia are currently integrated in this way although, in a number of instances, suppliers of gas transmission services have indirect links with gas production (eg Sagasco and AGL). Full integration of these functions would conflict with the intention behind requiring open access to the transmission and distribution networks. However, in view of the less developed state of the gas transport network compared with that for electricity, the generally high risks associated with gas production, and the desirability of providing adequate incentives for gas exploration, the Commission considers it inappropriate, at this stage, to preclude linkages between these segments through facilities such as joint venture arrangements - provided that, where these links exist, information on their nature and extent is publicly available.

7.4.3 Gas distribution - centralised or decentralised?

As with electricity, competition in distribution of natural gas would be promoted if there were multiple distributors in each state. In conjunction with an open-access requirement, this would permit border and by-pass competition and provide a better basis for comparative studies of performance (ie yardstick competition).

The size of franchise areas for gas distribution is currently determined by regulation. Franchise areas vary from those which cover an entire state or territory (eg GFCV in Victoria) to those which cover all or part of a city or township (eg Allgas in part of Brisbane and AGL's franchises in New South Wales).

The considerations which have influenced the determination of franchise areas are not clear, though they seem to be largely historical. For example, manufactured coal gas distribution franchises were allocated for an entire township or municipality, since the initial reason for the franchise was street lighting. Mergers or takeovers of gas franchise operations over the years seem to have been motivated, in part, by commercial considerations.

As with electricity distribution, the appropriate franchise area should be sufficient to allow the utility to capture significant economies of scale. While this may require the operation of a relatively large network, it is unlikely that it would be necessary for a single utility to operate a state-wide franchise. Due to the distance involved, it is likely that each city and township would require its own technical and support staff. However, some gains may be realised if contracts to purchase gas were handled through a central body. Similarly, other significant purchases (eg information systems) might be acquired more economically on a co-operative basis. On the other hand, there may be diseconomies associated with granting a franchise over a single large network for a large city such as Melbourne or Sydney. Indeed, two franchises have been allocated to service the city of Brisbane - one for the north and the other for the south. However, in this context, Sagasco observed in its submission on the draft report that:

> The Australian gas distribution industry (notably in Victoria and New South Wales) formerly consisted of a number of smaller gas companies within each state. The unforced consolidation of these companies into larger entities in Melbourne and Sydney would seem to point to recognition of efficiency gains through cost savings.

The Commission recognises that the question of the ‘optimal’ franchise area is an empirical one and will be influenced by a number of considerations which affect the profitability of supplying users, including the density of customers on a given network. Participants were requested to provide information to assist the Commission in addressing this matter, but virtually no data were forthcoming. However, the Commission considers that granting a franchise over areas as large as a state/territory should be approached with caution. Franchises over large areas and the associated concentration of utility ownership stifle the potential for competition between regions.

AGL is the sole distributor of natural gas in New South Wales, other than Albury which is serviced by the GFCV. However, AGL has multiple Authorisations covering the different regions in which it operates. Thus, although subject to central management, to some extent there exists already a number of separate franchises in New South Wales. If franchises are subject to tender at regular intervals, as recommended to the Commission, it would be appropriate at that time to consider the merit of limiting the ability of a single person, or associated persons, to maintain a dominating interest in New South Wales. This should also be considered when forming multiple franchises in Victoria, South Australia and Western Australia.

The Commission concludes that there is a strong case for dividing state/territory wide natural gas franchises in Victoria, South Australia and Western Australia into a number of separate franchise areas. This would provide a better basis for assessing prices and performance, and enhance the possibility of having competition for franchise rights. Judgments about minimum franchise sizes should be shaped by economic considerations *(such as economies of scale and scope). Following studies to determine the appropriate number of distribution units in areas which currently have state-wide franchises, proposed distribution units could be ring fenced Subsequently, separate franchises would be created for each ring fenced entity.*

7.5 Summary of proposals

Initiatives directed at actively promoting competition are needed to secure significant and sustained improvements in the performance of the ESI and the NGI in Australia. Given the current organisation of these industries and the dominant position of existing suppliers, the Commission considers that major structural changes are essential if these improvements are to be realised.

The Commission's main recommendations, which are directed at restructuring the ESI so as to increase competition, envisage a two-stage process. This would commence with the ring fencing of generation, transmission and distribution, and conclude with their transformation into fully independent bodies. The recommendations involve:

- ring fencing generation, transmission and, where not already separated, distribution assets in all states;
- dividing, by ring fencing, generating capacity in each mainland state and considering doing so in Tasmania and the Northern Territory;
- dividing, by ring fencing, distribution assets in the states of Western Australia, South Australia and Tasmania, and the distribution assets of the SECV;
- requiring distribution bodies to provide open access;
- requiring transmission bodies to provide open access and to be responsible for the operation and maintenance of the grid, merit order dispatch of generators, pricing of transmission services, planning of grid extensions and other coordination functions to maintain system integrity;
- developing a pooling arrangement based on four main markets - dispatch, security, wholesale and retail - for organising the sale of electricity prior to the full separation of ring fenced generation, transmission and distribution bodies;
- combining the transmission assets in New South Wales, Victoria, Queensland, South Australia and Tasmania to form an independent transmission body, initially owned jointly by each of the five states and the Commonwealth;
- making the ring fenced transmission body in Western Australia fully independent;
- making fully independent all ring fenced generating bodies;
- creating separate franchises for each ring fenced distribution entity;

- considering the amalgamation of small distribution authorities in Melbourne and the non-metropolitan areas of New South Wales, and dividing existing large distribution authorities in urban New South Wales; and
- requiring, by means of a Ministerial Direction, the Trade Practices Commission to oversight the development of new operating guidelines, mainly concerning access and pricing of network services. Once established, this arrangement would lapse and all industry activity could be made subject to the general provisions of the Trade Practices Act and the Price Surveillance Act. However, consideration should be given to requiring the Trade Practices Commission to coordinate all regulatory tasks, with accompanying modifications to the Trade Practices Act.

The Commission's main recommendations aimed at restructuring the NGI to promote competition envisage the same two-stage process as for electricity. The recommendations involve:

- ring fencing integrated transmission and distribution activities in Victoria and Western Australia;
- dividing, by ring fencing, distribution assets in Victoria, South Australia and Western Australia into a number of distribution entities;
- requiring all gas transmitters and distributors to provide open access;
- making fully independent all ring fenced transmission bodies;
- creating separate franchises for each ring fenced distribution entity; and
- requiring, by means of a Ministerial Direction, the Trade Practices Commission to oversight the development of new operating guidelines, mainly concerning access and pricing of network services. Once established, this arrangement would lapse and all industry activity could be made subject to the general provisions of the Trade Practices Act and the Price Surveillance Act. However, consideration should be given to requiring the Trade Practices Commission to coordinate all regulatory tasks, with accompanying modifications to the Trade Practices Act.

The two stage process underlying the Commission's recommendations recognises that the practical issues raised by ring fencing and full separation will take time to resolve. Ring fencing, which entails the notional separation of the main industry segments, represents a transitional step of up to two years duration, with full separation occurring as soon as possible thereafter. In view of the developments occurring in each industry and the need to achieve further reforms in a timely fashion, this time frame is considered adequate.

The Commission recommends a review by an independent body - in 3 years time - of the progress made in implementing reforms. Such a review would provide an opportunity to evaluate options for further improving efficiency in light of achievements in Australia and developments overseas.

8 THE QUESTION OF OWNERSHIP

Internationally, around 50 per cent of generation assets is privately owned. Private ownership brings with it the disciplines of the share and capital markets, the sanctions provided by the possibility of take-over and the risk of insolvency. It also significantly reduces the scope for interference by governments. Key segments of the electricity and gas supply industries in Australia could and should be owned and operated by the private sector. An examination of the opportunities for effective competition in these industries indicates that electricity generating stations and their fuel suppliers clearly fall into this category, while both gas and electricity distribution could be transferred to private hands. It is only in the transmission segment that the advantages of private ownership are uncertain. This arises because of its strong natural monopoly status and difficulties in devising effective regulatory regimes to deal with concerns about abuse of market power.

This chapter addresses a number of issues associated with the question of ownership. The discussion commences with a review of the main arguments advanced in support of continuing public ownership (Section 8.1). This is followed by an examination of whether it matters if governments retain ownership (Section 8.2). Issues bearing on realising the potential gains from transferring ownership to the private sector are addressed in Section 8.3 while alternative ownership structures are discussed in Section 8.4. A summary of the Commission's proposals is presented in Section 8.5.

8.1 The case for public ownership

As presently structured, over 90 per cent of the ESI in Australia is publicly owned and operated. Within the NGI, there is a smaller, but substantial government presence. A number of arguments have been advanced to explain the high level of government ownership, including:

- the natural monopoly characteristics of the industries, and related concerns about the abuse of market power;
- the inability of private suppliers to address social and development objectives satisfactorily;
- concerns about energy security; and
- the inability of private suppliers to finance the large investments required in these industries.

Given the diversity of ownership structures within the NGI in Australia and similar diversity in the electricity industry in other countries, the question arises as to whether these arguments provide a continuing justification for public ownership.

Natural monopoly and concerns about market power

Provision of electricity and natural gas by government owned enterprises is sometimes linked to cost economies in transmission and distribution, and the perceived need to restrict the number of suppliers so that the resultant benefits of single firm production can be captured and distributed to the community. It has been argued that, in the absence of government provision, competition between private suppliers might lead to costly duplication of infrastructure and ultimately to higher prices. Creating a legislative public monopoly is seen as a means of avoiding this outcome.

The argument favouring a publicly owned monopoly supplier is founded on the notion that it is easier to induce efficient pricing and production practices through a public enterprise than by regulating a private monopoly. This rests on two presumptions. First, that public enterprises are more likely to act in the 'public interest' by restraining prices to reflect their costs of supply. In contrast, a private monopolist may be more inclined to charge what the market will bear. Second, that the information required by regulators to promote efficient pricing and production decisions can be more readily obtained from a public enterprise.

Although a public enterprise may charge cost-reflective prices, its costs may well exceed those of a private monopolist because it faces fewer incentives to produce efficiently. Consequently, the prices set by a public monopoly could exceed those which a private monopolist would charge. Further, it is not clear that the costs of regulating a public enterprise would be below those of a private monopolist since, in both cases, managers have an information advantage over the regulators (government) in respect of detailed knowledge of market demand and supply conditions.

Opinions on this issue vary, as evidenced by the differing responses of Australian governments to the management of monopoly suppliers in the NGI. For example, gas transmission and distribution is a public sector monopoly in Victoria while, in Queensland, these functions are mainly carried out by regulated private suppliers. In the case of electricity, some countries, including Australia, have opted for public sector monopoly provision, while others have elected to regulate private suppliers, or a mixture of private and public suppliers.

In examining alternative policy responses to the problems created by market power, a key issue is the strength of market disciplines on an operator in the natural monopoly segments of these industries and the associated need for regulation and its effects on economic performance. This issue is examined further in Section 8.4.

Social and development objectives

A further reason put forward to support public provision of electricity and gas is the attainment of social and development objectives. Such objectives may encompass the provision of energy services to certain users below cost and safeguarding the environment.

For example, it is sometimes argued that elements of electricity (and possibly gas) have ‘essential good’ characteristics akin to public goods, and that private provision would lead to a pattern of supply less than that considered ‘socially acceptable’. This ‘problem’ does not arise because of any difficulty in charging users, but rather because the distribution of electricity and gas to some areas (eg farms and remote communities), may not be sufficiently profitable for a private supplier to provide it at a ‘reasonable’ price. Interestingly, some private distributors of gas are not obliged to supply gas if they are unable to get an economic return.

Even if society considers that there should be universal access, or access to some notional minimum amount of energy services at a ‘reasonable’ price (implying subsidised provision to some users), this would not necessitate continuing public ownership of utilities. Discounts to pensioners on their purchases of gas are currently provided by Sagasco (a mixed enterprise) in South Australia and by AGL (a private utility) in New South Wales. As discussed in Appendix 5, these objectives could be met in more effective ways, such as by direct subsidies to users or by providing a subsidy to cover the cost to a private supplier of providing the good or service.

The same observations apply to any proposals for the subsidised provision of electricity and gas to industrial users in order to promote regional or economic development objectives.

Preference for continuing public ownership of energy utilities may have more to do with the scope it provides for hiding the costs of bestowing favours on particular interest groups. In discussing this aspect of the differing impacts of public and private production on public policy, the Economic Council of Canada (1986, p.26) in a report on Minding the Public's Business commented:

> By manipulating production and prices, governments may be able to do, indirectly, what would be politically very difficult to achieve through the more direct instruments of intervention necessary in the presence of private capital. Public production becomes an extremely subtle mode of intervention where objectives can be altered without public notice or public debate, and where the requisite cost can be covered by internal operating funds. Financing in this case is achieved by a program of cross-subsidization, wherein money-losing activities are subsidized by other profitable production. The effect is to make both the costs of pursuing particular objectives and the extent of any associated redistribution less visible.

The charters of some public electricity and gas enterprises require them to have regard to the environment policies of their governments. In other cases, specific legislation covering a variety of environmental matters (such as emission controls and planning requirements for new infrastructure) applies to public as well as private suppliers. Thus, the pursuit of environmental objectives does not require public provision of energy services. Safety and other technical/service objectives could simply be attained by clearly establishing the ‘rules of the game’ for existing and new players.

Energy security

As AMIC observed:

> The essential role of energy, and in particular electricity, in the functioning of a modern industrial economy has been used to justify widespread government intervention in energy markets throughout the world. There is a belief that a private electricity market will under-supply ‘energy security’ for similar reasons to other ‘public goods’ such as national defence, law and order and, some would argue, education.

However, arguments relating to energy security do not necessitate the public production of either electricity or gas. Both forms of energy are privately marketed in many countries and there is no reason to presume that security of supply need be greater under one form of ownership than another. Moreover, security of supply (measured in terms of, say, a low level of interruptions) comes at a cost. There is a need to balance the cost against its value to users. This can be achieved by setting charges in accordance with a user's preference for security of supply. Indeed, long term supply contracts, premiums on gas supply for priority access and interruptible tariffs - all of which exist currently in Australia - are examples of market-based mechanisms for achieving the energy security objectives of particular users. The same mechanisms are used to provide similar security to users in a wide range of other markets where stability and reliability of supply are desired.

The practice or intention in Germany, Japan, New Zealand, the United Kingdom, the United States and elsewhere suggests that concerns about energy security do not require government ownership of all, or even part, of the electricity and gas industries.

Financing large investments

The electricity and natural gas supply industries are highly capital intensive. According to ESAA figures, the total capital stock of Australia's electricity utilities, covering power generation, transmission, distribution and other fixed assets, totalled in excess of $40 billion as at 30 June 1990 (on an historical cost basis). On a current cost basis, their value is around double that amount. The New South Wales and Victorian systems were each valued in excess of $12 billion (on an historical basis). Further, the public utilities responsible for electricity in these two states had outstanding debts of $6.3 and $8.7 billion respectively, while the industry's total indebtedness stood at around $25 billion at 30 June 1990. The costs of extending capacity are relatively high (eg a large coal-fired power station is typically in excess of $2 billion).

According to TPA, the construction of a large natural gas transmission pipeline, from (say) Dampier to Moomba, could cost in the vicinity of $6 billion.

It has been suggested that private firms would experience difficulty in participating in these industries, other than on a small scale. Hence, it is contended that reliance on such firms alone would result in inadequate supply of the necessary infrastructure, inhibit the development of energy intensive industries and retard economic growth.

This suggestion may have had some currency in the past. However, it is not relevant today. The development of capital markets and more flexible institutional arrangements, such as joint ventures or consortiums, have given private firms the capacity to organise finance (equity and debt) for very large scale projects. For example, the North West Shelf project has involved private investment of around $12 billion. The private sector has already sought to supply new capacity in the ESI in New South Wales and Western Australia. It has also expressed interest in purchasing the Dampier to Perth pipeline from the Western Australian Government. Recent proposals to sell power stations to the private sector in Queensland and Victoria and the proposed sale of the Commonwealth owned gas transmission pipeline from Moomba to Sydney indicate that governments consider that the private sector can handle such large investments.

Ironically, it could well be the public sector which is financially constrained. In commenting on private sector involvement in the ESI during this decade, the then President of the ESAA, Mr Jim Smith stated in March 1990 that:

> The squeeze ... on borrowing levels and our own debt levels are inevitably going to make private sector involvement more likely in the 1990's because it would allow more scarce funds to be put into social infrastructure such as education and health.
>
> More private sector involvement is not going to be popular within utilities. But in our industry around the world there are just as many successful investor owned companies as successful public utilities - and both have had their disasters too. Internationally, there does not seem to be any arguments based on service or financial performance in favour of public ownership....

Finally, it is important to recognise that the current levels of private sector involvement (which is minimal in the case of electricity), cannot be taken as an indication of any inability of the private sector to participate. It is more a reflection of the legislative barriers to entry which characterise both industries, as well as the institutional advantages available to government utilities. These advantages include the artificially low cost of funds due to loan guarantees, tax exemptions and the absence of requirements to earn commercial rates of return.

The Commission concludes that with one possible exception - where market disciplines applying to single suppliers in parts of the electricity and natural gas industries are weak - there is nothing special about these industries which necessitates continuing public ownership.

8.2 Does it matter if governments retain ownership?

The effect of ownership on economic performance has been the subject of considerable debate in Australia as well as overseas. Submissions to this inquiry also reflect wide differences of view.

The efficiency case for the transfer of ownership to the private sector rests on perceived deficiencies in the incentives structure of public ownership itself. Indeed, as the Western Australian Government observed in its initial submission:

> It has long been argued that private ownership and the pursuit of profit maximisation can act as a disciplinary force on an organisation so as to make it more cost-effective and technically innovative than public enterprises. This is in part the result of market forces imposing greater discipline over the management of the organisation concerned.

As recognised by BHPP in its draft report submission, ownership issues are also important for the electricity and gas industries because:

> ... the current industry structure has prevented fair competition and blocked commercial access to the transmission networks.

In this context, transfer of ownership offers a means of promoting greater competition within these industries.

In principle, the case for asset transfers rests on factors specific to the ownership of public enterprises which impair their efficiency. The two most important factors are the absence of certain disciplines which apply to private firms and the consequences of undue government involvement in the operations of public enterprises.

The absence of certain disciplines applying to private firms

Even after corporatisation, public enterprises would remain untouched by a number of market disciplines which automatically apply to incorporated private enterprises. These include:

- the ability of private shareholders to trade in the equity capital of the enterprise;
- the requirement to compete for debt capital on commercial terms;
- the exposure of investment and/or borrowing programs to continual monitoring by the capital and share markets;
- the sanctions of takeover or merger for inferior performance arising from, say, the under-utilisation of capital; and
- the risk of insolvency.

Of course, these disciplines may operate somewhat imperfectly. Private enterprises may have objectives other than profit maximisation, managers may not always act in the interests of shareholders, sharemarkets may not always serve as adequate performance monitoring mechanisms, and the threat of takeover and risk of insolvency may not always lead to improved performance by management. Nevertheless, even if imperfect, these mechanisms do not apply to public enterprises.

Government Involvement In utilities' operations

The second source of difficulty for public enterprises arises from their relationship with government, which limits the commercial freedom of managers. Problems arise from the specification of commercial as well as non-commercial objectives by governments, government interference in operating decisions and pressures (eg from suppliers, employees and customers) to pursue short term political goals.

Even after corporatisation, there could be no guarantee that governments will be able to resist pressures to intervene.

The Commission's view

A number of participants (including CRA, AMIC and BHPP) provided examples of production and pricing inefficiencies related to the operation of public electricity and gas utilities. Some of these inefficiencies, documented in Chapter 3 and 9 of this report, can be attributed to government ownership.

Some can be addressed through the reforms canvassed in Chapters 5, 6 and 7. But the gains from these reforms could be put at risk by political intervention which weakens the commercial relationship between public enterprises and governments. If short term political imperatives loom large in the minds of governments, it may be difficult to avoid the temptation to use public utilities to provide short term palliatives, even if their long term ramifications are deleterious.

Thus, while administrative changes and measures to promote competition can increase incentives to operate efficiently, inefficiencies may well remain and apparent gains may be only short-lived so long as ownership remains with governments. This assessment was endorsed by a number of inquiry participants including BHPP which stated:

> We do not believe true corporatisation is possible. Regulatory actions cannot effectively mimic competitive pressures, and while corporatisation can improve efficiency, the efficiency gains achieved often are limited by the increased regulation which often accompanies the process. In addition government-owned bodies always are vulnerable to the increased political pressures which arise during economic downturns.

Enterprises involving a mixture of public and private equity have been put forward as one means of addressing some of these difficulties. Examples include GFCV and Sagasco, both of which have a minority private shareholding. In discussing the expected patterns of behaviour of mixed enterprises relative to the alternatives, Hensher (1986) observed that:

> ... the role that private shareholders can play in influencing the government's direction of the organisation ... will depend on the percentage of private ownership and the concentration of such ownership.

In principle, where governments retain a dominant shareholding and also impose special conditions on trading in the private equity component of the enterprise (as applies in the case of the GFCV and Sagasco), there would probably be little difference in the behaviour of a mixed enterprise and a fully public enterprise. In discussing the setting of tariffs by Sagasco and ETSA, the South Australian Government stated:

> The objectives for setting Sagasco prices are essentially the same as those of ETSA, although being a company incorporated under the Companies Code the scope for achievement of non-commercial Government objectives is more restricted.

In commenting on the same arrangements, Sagasco indicated that:

> ... inadequate cash flows arising from limitations on its tariffs to metropolitan and regional consumers have forced it to limit extensions to the network, although its management believes that that course is not necessarily beneficial to the development and growth of the State.

In the Commission's assessment, there are important in-principle differences in the structure of incentives and disciplines characterising public and privately owned firms. Ownership clearly does matter. The transfer of ownership has the potential to significantly alter these incentives and disciplines, and thereby managerial behaviour and economic performance.

In practice, the competitive and regulatory environment interact with ownership to shape actual performance. Hence, the effects of ownership cannot readily be isolated.

Both the electricity and gas supply industries are characterised by varying opportunities for competition, and the market power available to firms within parts of these industries has given rise to regulatory mechanisms aimed at limiting abuses of that power. Thus, having regard to these real world complications, the question arises - what does the empirical evidence reveal for activities like electricity and natural gas?

The Commission is unaware of any studies which have examined the comparative performance of public and private firms in the NGI. International studies are available for electricity generation and distribution, as well as for a number of other industries which exhibit natural monopoly characteristics such as water, railways and aviation. Such comparative performance studies are fraught with difficulties because there are few instances where private and public enterprises carry out comparable activities in similar working environments. These studies were reviewed by the IAC as part of its inquiry into Government (Non-Tax) Charges (1989) and the results suggest:

- Product market competition seems to make the strongest contribution to enhancing efficiency. Accordingly, policies directed at removing legislative barriers to competition should be given priority.

- Where effective competition occurs (or is technically feasible), private enterprises generally operate more efficiently than public enterprises. There is, therefore, no justification for retaining public ownership in such cases.

- Transfers of ownership in the presence of legislative barriers to competition are unlikely to be productive in promoting better performance.

- In situations characterised by significant market power (such as natural monopoly) with extensive regulation, it is difficult to discern any real differences in the performance of public and private enterprises.

Thus, while the ownership status of an enterprise clearly has important effects on the incentives and disciplines for enterprises to minimise costs, make appropriate investment decisions and price efficiently, these effects interact with those of competition and regulation. Thus, getting the competitive and regulatory environment 'right' is vital if the potential gains from the transfer of ownership are to be realised. This assessment is supported by a number of studies covering these issues (De Alessi 1974; Joskow and Schmalensee 1983; Yarrow 1986; and Kay, Mayer and Thompson 1989).

The implications of these considerations for the choice of ownership form in the electricity and natural gas industries are two fold. First, where there is the potential for effective competition (eg fuel sourcing and generation) there is no case for retaining government ownership. Second, in circumstances characterised by market power (eg the natural monopoly segments of these industries, particularly transmission) the question of whether or not to retain government ownership hinges on the strength of this market power and the costeffectiveness of regulating a public compared with a private monopoly.

Within the ESI there is evidence of a growing recognition of the case for the transfer of assets or functions to the private sector where there is scope for effective competition. For example, ECNSW has sought to promote competition in areas such as fuel sourcing and private power station ownership. It is currently in the process of selling its coal mines having judged that the coal market is contestable. SECWA's next major power station is to be privately built and operated and the SECV wishes to sell Loy Yang B power station. Within the NGI, transmitters rely on private operators for their supplies of gas. Electricity and gas utilities throughout Australia are also drawing more extensively on private contractors to undertake a variety of functions as an alternative to 'in-house' production.

8.3 Realising the potential gains from the transfer of ownership

The transfer of public assets to the private sector raises a number of issues which bear on the potential for realising gains from the process. Key issues include:

- the competitive and regulatory environment;

- the impact on the net worth of the public sector;
- the impact on the tax base of state and territory governments;
- industrial relations;
- the effects of ownership limits;
- concerns about foreign ownership and control; and
- the impact on financial markets.

Each of these issues is addressed briefly below.

The competitive and regulatory environment

Competition and regulation seem likely to be more fundamental determinants of the economic performance of electricity and gas enterprises than their ownership status, particularly in areas like transmission and distribution. Accordingly, the Commission considers that governments should, in the first instance, give priority to removing legislative and institutional barriers to effective competition and to improving the effectiveness of regulations to deter anti-competitive behaviour as a means of improving performance.

Without change in these areas, the potential gains from asset transfers are unlikely to be realised, largely because the incentive to improve efficiency will be reduced by the absence of effective competitive pressures and/or the perverse effects of inadequate regulatory controls over market power and access conditions for transmission networks. Furthermore, in the absence of a neutral environment and greater certainty about the future organisational structure and regulatory environment, private sector interest in acquiring government assets could be substantially reduced.

Impact on the net worth of the public sector

Gains to the community from asset transfers depend primarily on the realisation of efficiency improvements from privatisation. If this is the case, the present value of expected future income from the privatised enterprise would exceed that expected under continuing public ownership. Sale prices should reflect such expectations and give rise to an improvement in the net worth of the public sector.

A potential conflict may arise because the revenue from the sale of a public enterprise is likely to be greater if the enterprise is transferred to the private sector with restrictions on competition still intact and/or inadequate regulatory controls over the abuse of market power. However, potential efficiency gains from such a transfer (which should be the main motivation for considering such transfers) would be placed at risk in such cases.

Impact on the tax base of state/territory governments

Under existing taxation provisions, state/territory governments may levy the equivalent of the current federal company income tax on the surpluses of their electricity and gas utilities. If ownership was transferred to the private sector, the Commonwealth Government would benefit since company tax liability would apply to the new enterprises and, in the absence of any offsetting adjustment, the budgetary positions of state/territory governments would deteriorate.

This factor could jeopardise reforms within the electricity and gas supply industries. Consequently, consideration needs to be given to providing state/territory governments with a payment equivalent to the tax revenue foregone. The Commission understands that a similar arrangement applies under the Public Utilities Income Tax Transfer Act in Canada. One difficulty with this approach is in quarantining such arrangements to ‘meaningful’ reforms.

This matter was addressed at the 1990 Special Premiers' Conference. In their communique, the leaders `recognised that the potential loss to State Governments of tax-equivalent streams of income as a result of the change in ownership of enterprises could be an impediment to micro-economic reform and welcomed the Commonwealth's policy of in-principle commitment to compensation'.

Industrial relations

In its response to the draft report, the ESAA indicated that there could be industrial relations difficulties in selling operating power stations. The Commission is aware that the SECV's proposed sale of Loy Yang B power station in Victoria has encountered opposition from the labour movement, as has possible private sector involvement in generation in Western Australia. Attempts at contracting out some costly ‘in-house’ activities to the private sector have also been opposed. Similar concerns have arisen in sectors of the NGI.

These developments challenge the industry and its workforce to review existing work practices and the scope for improving labour productivity by revising current working arrangements. Failure to respond to these opportunities may, in the short term, preserve jobs and working conditions in the ESI and NGI. However, in the longer term, the maintenance of outdated managerial and employment practices will result in energy charges being higher than they would otherwise be. In turn, this will limit employment opportunities elsewhere in the economy and diminish living standards generally.

The effect of ownership limits

Experience with the sale of publicly owned enterprises in other countries indicates that governments have often taken the view that some enterprises have significant national interest and should be protected. A variety of mechanisms may be used, including prohibitions on one person having a shareholding interest of 15 per cent or more, prohibitions or limits on foreign ownership, and restrictions on the disposal of a significant proportion of the enterprise shareholding. In the United Kingdom, a special share (often characterised as a 'Golden Share') has been used by the government. It has been used to establish certain provisions in the privatised enterprises' articles of association which cannot be altered without the Government's permission. In the case of British Gas, it has been used to establish a 15 per cent voting restriction and a limit on the issue of new voting shares. The special share could be used to give the government a say in the running of the enterprise or participation in its profits.

The use of regulations to control ownership affect the efficiency goal of asset transfers. The restrictions appear in the main to be directed at protecting enterprises from takeover activity and placing limits on foreign investment and control. As discussed in Chapter 6, the Commission does not consider that shareholding restrictions can be justified. Its views about foreign investment and control are set out below.

Concerns about foreign ownership and control

In responding to the draft report, a number of participants, including the ESAA, indicated that asset transfers involving the possibility of significant foreign ownership could be a cause for community concern.

The Australian Government's foreign investment policy requires that any proposals for the acquisition of existing electricity or gas enterprises with total assets valued at $5 million or more be examined by the Foreign Investment Review Board. Such proposals are approved unless judged by the Government to be contrary to the national interest. The Commission considers that this policy provides adequate scope to consider community concerns.

Effects on financial markets

A number of utilities and the ESAA pointed out that the current value of public sector generation and distribution assets in the southern and eastern states amount to more than $60 billion and questioned the capability of financial markets to cope with transactions of this order. For example, the ESAA stated that the Commission's privatisation proposals would potentially:

> ... place an impractical demand on Australian capital sources.

If it were planned to sell all generation and distribution assets simultaneously, significant pressures may well be placed on the Australian capital market. But this is not the case. The Commission is proposing that assets be sold progressively. Sales would extend over a number of years. This factor, plus the closer integration of the Australian and international capital markets, should avoid unrealistic demands being placed on capital markets.

8.4 Alternative ownership structures

The following discussion explores the ownership options for the different segments of the electricity and gas industries having regard to the Commission's earlier recommendations on corporatisation, regulation of private utilities and structural changes to promote competition.

Electricity generation

The Commission recommends (in Chapter 5) that public electricity and gas utilities be corporatised. This will enable them to compete between themselves and with the private sector in a more neutral environment. The structural changes put forward for the ESI (in Chapter 7) will further reduce institutional barriers to competition by separating generation from transmission and providing for open access to the transmission grid. The Commission is also recommending that, following completion of ring fencing and the development of sub-markets for electricity, there be a limited break-up of electricity generation.

Within this restructured environment, the Commission considers that there will be sufficient opportunities for effective competition in generation to make specific regulation directed at dealing with the undesirable effects of the market dominance of existing generators unnecessary. The creation of regionalised generating enterprises, combined with greater private involvement in generation, would create stronger competitive pressures within this segment of the ESI. Competition between private and public generators is likely to be much more vigorous than that arising from competition between public enterprises alone. This assessment received widespread support from users and was recognised by the Western Australian Government (1989) in its discussion paper dealing with Power Options for Western Australia 1990-2000. It indicated that:

> Perhaps the most important benefit from a private power company may be its influence on competition. If the company could sell power to third parties as well as SECWA by using the interconnected grid as a carrier, there would be a direct competitive element against SECWA. This could be a stimulus to improve performance in SECWA's power stations and operations generally.
>
> ... SECWA's own power stations would have a standard of comparison. The private station's sent out power costs, staff complement, labour costs, work practices, plant availability and construction costs could all be compared with SECWA's equivalents.

The SECV also referred to the benefits of such competition in discussing the competitive disciplines imposed on Loy Yang Power Station by the CRA proposal to build a private power station at Oaklands in New South Wales. Further, in commenting on the possible sale of Loy Yang B, the Chairman of the SECV said that Victoria already has a privately owned and operated power station - Alcoa of Australia's 150 MW Anglesea power station - which operated much more efficiently and economically than comparable SEC units (SECV News Release, November 1990).

Private operators may also be better placed to negotiate improved work practices from a ‘fresh’ stand-point and offer flexible performance-based remuneration packages to their employees to promote higher productivity. Existing public operators (eg SECWA and SECV) have indicated that they have experienced difficulty in developing more flexible and commercial approaches to shift maintenance and the use of outside contractors in their power stations.

While the entry of private interests into generation could be achieved through competitive tendering for new capacity, the process could be accelerated by selling existing generating assets to the private sector. Under both approaches, a private generator would need to secure access to fuel sources and negotiate with the grid operator to sell its output. It would also have to meet various technical and operating requirements to ensure the effective operation of the overall system.

Private ownership in the generation sector is certainly practicable since around 50 per cent of the world's electricity generation assets is in private hands. Privately owned and operated power stations can be found in countries such as Belgium, Canada, Denmark Germany, Japan, Sweden, Switzerland and the United States and have been proposed for the United Kingdom and New Zealand.

The Commission concludes that there is no reason for governments in Australia to retain ownership of electricity generation assets. The generation of electricity is a contestable activity and, subject to the creation of effective competition in this industry segment through the separation of transmission from generation and the provision of open access to the transmission grid, it would be desirable for governments to sell progressively their existing generating capacity to the private sector.

Electricity and gas transmission

Electricity and gas transmission facilities in most states are owned by public enterprises. There are, however, some exceptions - some gas transmission pipelines in Queensland, the natural gas pipeline and some electricity transmission assets in the Northern Territory, and minor gas transmission facilities in Western Australia. As noted above, the Western Australian Government is considering a number of expressions of interest from the private sector to acquire the Dampier to Perth gas pipeline.

Public ownership is not unusual for this natural monopoly segment of these industries. The potential for abuses of market power usually gives rise to some form of government intervention, and public ownership (with associated regulation) has often been the preferred response. However, as private ownership with accompanying regulation applies both in Australia and some overseas countries, the merits of alternative ownership models need to be addressed.

This issue has attracted considerable attention in recent years through, for example, the restructuring of the electricity and natural gas industries in the United Kingdom and New Zealand. A review of the United Kingdom reforms by Vickers and Yarrow (1988) and the Report of the Electricity Task Force (1989) in New Zealand identified the following ownership options for electricity transmission (which, subject to some minor modifications, could also be considered for natural gas transmission):

- a corporatised public enterprise;
- a club of generators with public and private ownership (the Swedish model);
- a club of distributors comprising public and/or private ownership;
- a club of generators and distributors comprising public and private ownership (the proposed NZ model); and
- independent private ownership.

In discussing criteria to assess these options, the New Zealand Task Force nominated: incentives for cost minimisation; the avoidance of entry barriers into generation; incentives for efficient pricing; incentives for dynamic efficiency (particularly in relation to system costs and investment decisions); and the desirability of minimising regulatory costs.

There is limited information on how these factors are affected by different ownership models. Wider studies of the performance of public and private firms suggest that, where there is significant market power requiring extensive regulation (such as a natural monopoly with limited competition from alternative products), it is difficult to discern any real differences between the performance of public and private firms. While the market power available to electricity and gas transmitters may be constrained somewhat by competition between electricity and gas and other sources of energy in some markets, the operator in the transmission segment of these industries has considerable market power due to the impracticality of direct competition from alternative suppliers. Consequently, inefficiencies arising from the likely monopolistic pricing practices of a private operator, albeit constrained by regulatory provisions, need to be balanced against likely cost savings arising from their superior productive efficiency.

Set out below are some broad observations on each of the ownership options mentioned above. Although the Commission specifically invited comment on the relative merits of these options at the draft report hearings, little comment was received.

A corporatised public enterprise

Public ownership of a separate transmission entity could confer some benefits. These include a lessening of entry barriers for new generators and distributors and the possibility of less complex regulatory requirements compared with other options. However, it also offers the prospect of wider interests shaping operating and investment decisions due to the scope for greater political interference. Consequently, incentives for managers to produce and price efficiently are likely to be diminished.

A club of generators

This option (the Swedish model) involves ownership by public and/or private operators of power stations or gas fields, with provision for an expansion of the club's membership with new entrants. It could offer cost advantages from the efficient use of the network and extensions to the network over time. However, barriers to new entrants could be created by existing generators making the services of the transmission company available on discriminatory terms. Further, since generators would have an interest in achieving as high a return as possible, they could elect to collude rather then actively compete, in which case they would be well placed simply to pass on any cost increases in the bulk supply market to the distributors and consumers of electricity. Consequently, disciplines on production and investment decisions could be relatively weak. This possibility reinforces the desirability of breaking up generation to promote effective competition between generators supplying bulk electricity to distributors/users. In the absence of such competition, the regulatory costs of guarding against misuse of market power could be quite high under this model.

A club of distributors

This option, which was supported by the New South Wales Electricity Council, involves ownership by public and/or private operators of existing distribution networks, with provision for expanded membership with new entrants over time. To some extent, the major considerations are similar to those of the previous alternative.

Distributors would presumably be keen to promote competition in the generation sector of the industry with associated efficiency gains. However, this option could promote collusion in the retail market for electricity and increase monopsony power within the industry. This possibility seems more likely for a club of distributors than for a club of generators because competition between distributors is likely to be less intense than between generators. As observed by Vickers and Yarrow (1988), the buying power of a distributor-dominated transmission grid/pipeline could have substantial damaging effects on economic efficiency. For example, the buying power of distributors could drive prices for bulk power below the costs of new capacity, resulting in under-investment in generation. The regulatory costs associated with seeking to avert such outcomes could be high.

A club of generators and distributors

This option is the preferred ownership structure for the New Zealand electricity industry. An independent Establishment Board was set up in July 1990 to oversee the separation of generation and transmission, the creation of Trans Power as the national grid company and the development of a club to be owned mainly by the industry. Generators and distributors will have equal shareholdings in the club (which is to be formed in July 1991). Independent private investors may also be allowed to hold shares in the club.

According to the Report of the Electricity Task Force (1989), the main reasons for favouring this option was that:

> ... these club owners, as users, would have a strong cost-minimising incentive leading to product efficiency, dynamic efficiency and low information costs, given the highly technical nature of the grid and its crucial co-ordinating function.

However, it was also stated that this preference was:

> conditional upon satisfactory resolution of club rules and entry conditions.

This qualification is important given the perceived weaknesses of this option in a number of areas, namely: its potential to create barriers to new entrants; uncertainties about accommodating the divergent interests of members in areas such as the apportioning of system costs to the different members; and determining in an unbiased fashion the relative merits of different investment projects.

A club of generators and distributors could produce outcomes which are likely to be highly sensitive to the rules specified for the operation of the club. In the absence of adequate rules, regulatory costs may be relatively high.

Independent private ownership

A major advantage of this ownership structure is its complete independence from the generation and distribution sides of the ESI. This would assist the emergence of a more competitive market for bulk electricity by promoting improved access to the grid, but it may require higher regulatory costs to guard against abuses of market power. In common with an independent public operator, this approach would need to establish a coordinating mechanism (with representation from the generation and distribution segments of the ESI) to review or advise on investment proposals. The costs of coordination and planning under this and the independent public ownership model could exceed those of the other models. However, unlike a public operator, the consequences of a poor investment decision by a private operator would be directly borne by the operator and users, rather than shifted on to the taxpayer, resulting in stronger incentives for productive and dynamic efficiency.

In the absence of strong market disciplines on a single operator of transmission services and considerable uncertainty about the regulatory costs associated with different ownership models relative to their benefits, the Commission considers it is not clear that a change of ownership of transmission assets from the public sector would improve efficiency.

Electricity and gas distribution

A variety of recommendations are being advanced by the Commission to improve the economic performance of electricity and gas distribution. The key recommendations cover:

- the corporatisation of public enterprises currently responsible for the distribution of electricity and gas;
- the separation of distribution from the other functions in integrated public utilities;
- the restructuring of utilities responsible for electricity and natural gas distribution through the creation of multiple franchises in those states in which there is only one franchise; and
- a number of regulatory reforms for electricity and gas distributors involving the removal of sole area franchises and obligations to supply in favour of franchises subject to periodic competitive tendering, an open access requirement for distributors and the threat of regulation in the event of restrictive business practices.

The adoption of these recommendations would, in the Commission's view, increase competition between distributors within each industry and also between distributors of electricity and gas.

While the distribution of electricity and gas currently exhibits natural monopoly characteristics, it is different in nature from that applying to the transmission function. It is possible to realise the benefits of single firm supply of distribution services with a larger number of distributors than transmitters in either of these industries. Thus, while it might be uneconomic to seek to promote competition by duplicating distribution infrastructure within the same area, a single distributor can be subjected to more competition than a single transmitter and therefore has less market power. For example, opportunities exist for competition at the borders of franchise areas, while an open access requirement could stimulate competition within franchise areas. Moreover, there is greater competition from alternative energy suppliers than is the case with the provision of transmission services..

The changes recommended by the Commission would also facilitate the development of more rigourous performance monitoring mechanisms since the existence of more than one distributor (within say a state) would provide greater information for comparing and contrasting the performance of differing distributors. Such information could be used by distributors and/or regulators to distinguish those aspects of performance which can be linked to superior management from those which are outside the control of management. This information could in turn be used to create greater pressures for competition between distributors than is currently feasible (so-called 'yardstick competition') and/or to design better regulatory provisions to monitor cost structures, pricing and service provision.

In summary, distribution as well as transmission has natural monopoly characteristics. However, unlike transmission, there is scope for competition in distribution activities. As a result, the potential for distributors to exploit market power would be less than that available to a transmitter, and associated regulatory costs would also be lower.

Greater participation by the private sector in electricity distribution could provide benefits similar to those discussed for generation, including more intense competition and stronger demonstration effects for the managers of publicly owned and operated distribution authorities. In this context, the SECV stated in response to the draft report:

> The SECU ... has no intention of selling any distribution assets. It intends rationalising the number of District Business Centres (DBCs) to create somewhat larger units and would then consider a trial of the separate franchising of the management of some of these distribution areas, ...

Within Australia, participation by the private sector in gas distribution in some states and territories demonstrates that wider private involvement in this industry is certainly feasible. Private firms are involved in the distribution of electricity in a number of other countries including Denmark, Germany, Japan, Sweden and the United States. The restructuring of this industry segment to create multiple distribution areas would significantly lessen the market power available to existing operators and increase the feasibility of encouraging greater private sector involvement to promote better performance.

The Commission concludes that there is considerable scope for realising further efficiency gains in distribution by expanding private sector ownership in the distribution of electricity and gas.

8.5 Summary of proposals

An examination of the arguments for continuing public ownership in the electricity and gas industries indicates that, with the possible exception of the transmission segment of these industries, there is nothing special about them which justifies continuing public ownership. Since ownership clearly affects the incentives and disciplines for enterprise managers to produce and price efficiently, an in-principle case exists for privatisation.

A review of studies of the comparative performance of public and private enterprises reveals that there is a strong likelihood that benefits will arise from transferring ownership from public to private firms where there is scope for effective competition between suppliers (eg fuel sourcing and generation). The separation of transmission from generation, the provision of open access to the transmission grid and the corporatisation of existing public entities involved in these areas, are fundamental to promoting effective competition between generators. In contrast, transmission is characterised by significant market power. There is considerable uncertainty about the relative costs of regulating different forms of ownership in this segment. It is unclear that a change of ownership would improve efficiency. In the case of distribution, market power is less significant and scope exists for promoting more competitive outcomes through industry restructuring and associated ‘yardstick competition’ with supporting regulatory initiatives. Accordingly, subject to the adoption of initiatives to promote competition in generation and distribution canvassed elsewhere in this report, the Commission recommends that:

- governments progressively sell their existing generating assets to the private sector; and
- governments progressively sell, at least some of, their electricity and gas distribution assets to the private sector and evaluate the performance of private distributors relative to public distributors. This could lead to more extensive transfers of ownership.

9 PRICING

Efficient pricing is a necessary condition for efficiency in production and consumption of electricity and gas. Although some changes have been made, present pricing practices fall short of efficient pricing. Tariffs should recover all economic costs of supply. They should also reflect those costs more accurately to users. Wider availability of time-of-use tariffs and greater use of access charges to recoup fixed costs would increase pricing efficiency. Ultimately, pricing efficiency is only likely to be achieved if there is a shift from administratively based to market driven pricing.

9.1 Introduction

Pricing practices have substantial implications for economic efficiency. If prices are 'too high', users are effectively taxed and competitiveness is reduced. If prices are 'too low', users are subsidised. However, where any such shortfall arises from public utilities' pricing practices, it will have to be funded from government revenue and other groups in the community will be disadvantaged. More importantly, low prices will encourage excessive levels of consumption which will signal the need for expansion in capacity which would not be necessary if prices were set on an appropriate basis.

There is debate about what constitutes efficient pricing. However, as discussed in Chapter 3, the Commission considers that, as far as practicable, prices should reflect the efficient cost of supply. Thus, efficient pricing has two major elements: least cost production (to ensure that costs are minimised) and prices to reflect supply cost. This chapter deals primarily with the second requirement; that prices should accurately reflect marginal costs of supply. At present this does not generally occur.

The following sections summarise current pricing practices in the electricity and gas supply industries, highlight deficiencies in existing pricing arrangements where they fail to reflect costs accurately, and consider means of improving pricing efficiency.

9.2 Current pricing practice

Electricity

Pricing for electricity covers two major areas - the wholesale pricing of electricity from the utilities to the distributors and the retail pricing of electricity to consumers. The special cases of pricing electricity for interstate sales and of buyback tariffs are discussed in Appendices 6 and 7, respectively.

In New South Wales, Queensland and parts of Victoria, electricity distribution is separate from generation and transmission. New South Wales and Queensland sell power to distributors under a Bulk Supply Tariff (BST). In New South Wales, the BST is uniform to all distributors and has an energy charge and a supply charge which ECNSW stated largely reflects system fixed costs. The energy charge has a time-of-use element with off-peak, shoulder and peak rates, although the structure is the same for all seasons. A different energy cost schedule is applied according to the voltage at which electricity is delivered.

The Queensland Government outlined the BST arrangements in that state. It noted:

> The amount of money payable by each of the Electricity Boards to the Queensland Electricity Commission for electricity supplied each year is calculated by applying a notional uniform bulk supply tariff to the projected electricity consumption of each Board. To these amounts are added (or subtracted) transfers needed to enable all Boards to balance their budgets. (This is essential because of the uniform retail tariffs supplying [sic] in Queensland and the different cost structures of the seven Electricity Boards).

The BST employed in Queensland is a block tariff. The Rainforest Conservation Society (RCS) said that, under this system, a fixed amount of electricity is allocated to each Electricity Board each year and a fixed charge made for that block, irrespective of the demand and energyy actually incurred by the distributor.

In Victoria, sales to independent distributors (the 11 Metropolitan Electricity Undertakings) are based on fixed dollar margins per customer category plus, in some instances, a variable margin on sales. A crude time-of-use element is included, with a fixed margin for a domestic off-peak category ($40 per customer).

Retail tariffs usually categorise consumers into classes, generally based on the type of end-user. The major classes in common use are domestic, commercial and industrial classes. A farm class is also common. In each state except New South Wales, uniform tariffs apply within each class, regardless of distance between generating plants and the point of use. A domestic user in Brisbane, therefore, pays the same price as a domestic user in Cairns and townships on the Cape York Peninsula.

A number of different tariff structures are used. A flat tariff is the simplest. It is sometimes used for domestic and small commercial and industrial consumers. An additional fixed charge, independent of consumption, is often levied to account for the cost of connection, metering and servicing the account. Declining block tariffs, where the price for units in each block is higher than those in succeeding blocks, are also common for domestic and small commercial and industrial users. The higher charge for the first block is designed to cover most or all fixed costs. Time-of-use tariffs, where the energy charge varies with the time the electricity is used, are increasingly being applied. Energy charges are increased for periods of high demand (when the cost of supply is relatively high) and decreased for times of lower demand.

Most large commercial and industrial users can also elect to take supplies under arrangements which incorporate a demand charge (which depends on the maximum demand recorded over the billing period), plus an energy charge (based on the quantity of energy consumed over the period) and a fixed service charge.

Many major users of electricity take their supplies under contracts (usually confidential) entered into with supply authorities. These contracts, which could be viewed as madeto-measure tariffs, are designed to reflect specific user's requirements. They may enable supplies to be interrupted at times of peak load or system stress in return for lower electricity prices. Examples include interruptibility contracts with aluminium smelters in New South Wales and Victoria. Contract sales to major customers can potentially reflect supply costs more accurately, because the associated costs can usually be identified more readily. Further, the additional effort in identifying costs is justified as the size of sales increases.

For private generation of electricity (including cogeneration), the price for electricity purchased by authorities and tariffs for purchases from the grid are relevant . Purchases by utilities usually involve two elements: fixed charges associated with connection to the grid and a price for electricity produced. This price is usually based on avoided cost. It may, however, also be determined by negotiations between private generators and electricity authorities. In this regard, the New South Wales Government noted:

> Prospective private generators are being made to compete with one another rather than offering fixed buy-back prices which would be to the disadvantage of consumers.

The tariff facing private generators for purchases above normal requirements (eg when a cogeneration unit is not producing due to repairs or an unplanned outage) usually incorporates an element for standby charges. Hence, this standby tariff is usually higher than the normal retail tariff. (Tariff arrangements for cogeneration are treated in more detail in Appendix 8.) In Queensland, somewhat different arrangements apply. In general, standby charges are usually levied as a monthly charge to cover the cost of provision of capacity which would be required in the event that supply is taken. When supply is taken, it is provided at standard tariffs and rebated against the standby charges for that month.

Gas

Gas users have traditionally been divided into three classes; domestic, commercial and industrial. Separate tariff arrangements (and levels) usually apply to each class.

A further division of tariffs is between prices for direct contract sales to large consumers and prices charged to other consumers through gazetted (published) tariffs. Prices for contract sales are lower than the relevant gazetted tariffs. The proportion of contract sales varies considerably - in New South Wales, they account for about 80 per cent of total gas sales while, in Victoria, they account for about 50 per cent. In Western

Australia around 98 per cent of commercial and industrial customers are supplied under contract. All domestic consumers are charged a gazetted tariff.

Gazetted tariffs for each user class are generally based on an access charge and a variable charge (block structure). The access charge is designed to recoup a proportion of fixed distribution costs. The major component is the variable charge based on consumption blocks. With the exception of Melbourne's domestic general tariff, which has a two tier increasing block structure, all tariff structures are based on declining blocks.

A separate gas transmission tariff operates in New South Wales, the ACT, South Australia and the Northern Territory. In other states, transmission is part of a vertically integrated operation and its cost is incorporated in the purchase price of gas or in the distribution tariff. In New South Wales, the same flat rate tariff is charged for the majority of gas transmitted. The transmission tariff for the ACT reflects the incremental capital costs attributable to the Territory, a proportion of the common costs of the Moomba to Sydney pipeline and a return on TPA's investment. In South Australia, PASA has a two-part transmission tariff which has an annual access fee (consisting of a customer related charge, a priority delivery charge and a fixed cost or capacity charge) and a variable charge for gas transmitted. Both PASA and TPA charges are based on the historical costs of fixed assets.

9.3 Short term pricing strategies

Two factors underlie present shortcomings in electricity and gas pricing. These are the failure to represent the full level of economic costs of supply and the failure of tariff structures to reflect accurately such supply costs.

Level of costs

To reflect supply costs it is essential that all appropriate costs be included and be accurately measured. Table 9.1 shows that estimates of cost recovery by electricity authorities in the five mainland States for 1989-90 ranged from 78 to 102 per cent. If the size of the capital stock in that year was optimal, this suggests inadequate returns on capital for all States except Western Australia. However, significant surplus capacity in the generating sector in some states suggests that the capital value of this capacity should be written down and, to reflect this, lower charges applied. With reductions in excess capacity arising from increased load growth over time, it would then become appropriate to raise charges to reflect the cost of the next increment of capacity.

Table 9.1: **Cost recovery by state electricity authorities, 1989-90**[a]

	NSW	*Victoria*	*Qld*	*Sa*	*WA*
Revenue ($m)	3 714	2 581	1 674	782	1 038
Costs ($m)	4 655	3 069	2 157	927	1 017
Cost Recovery (%)	80	84	78	84	102

a The methodology employed involved estimating the current value of assets and the application of an 8 per cent real rate of return.

Source: Lawrence, Swan and Zeitsch (1991).

At present, there are costs incurred in the supply of electricity and gas which are not properly valued. The most significant of these relate to depreciation and the rate of return on capital. Most utilities use accounting conventions which value fixed assets at historical cost rather than at replacement or market value. Because of the effects of inflation, depreciation and rate of return charges based on historic costs will be considerably below the economic cost of supply. For example, TPA depreciation charges would increase some 350 per cent if replacement (rather than historic) costs were used.

Some costs are not even included. Most utilities ignore the real cost of capital; rates of return are often not included or, where they are, may be at a very low level. Public utilities are also exempt from many government taxes and charges.

Although more difficult to identify and measure, pollution costs are another example. DASETT noted that, to the extent the existing supply authorities are obliged under environmental protection regulation to meet appropriate and acceptable environmental standards, such costs are internalised. However, it noted some environmental costs are not yet internalised. Without allowing for, say, any external costs imposed by burning fossil fuels for electricity generation or leaks from gas transmission and reticulation, the real cost of supply (and hence the price) would be understated.

The New South Wales Government noted that a recent German study (Hohmeyer 1988) indicated that allowing for the environmental costs of conventionally generated German electricity would double its cost. While costs of this magnitude are unlikely for Australia, excluding them is tantamount to treating them as zero. The need to account for environmental costs is being increasingly recognised as a problem for a wide range of activities.

While attention is being paid to determining environmental costs, accurate measurement of these costs is difficult. Further work is required to identify these costs, not only in the electricity and gas supply industries, but throughout the economy generally.

Other costs are inappropriately borne by utilities. These include costs from government imposed CSOs, such as uniform pricing, pensioner rebates and connection subsidies. Additional costs are also incurred if governments insist on specific solutions to problems (eg undergrounding of power lines or the relocation of transmission lines) rather than allowing utilities to solve them in a cheaper way. The inclusion of such costs inflates the true cost of service provision, as do inefficiencies in the supply of electricity and gas.

In recent years, some utilities and Governments have introduced changes to overcome some of these difficulties. For example, some utilities have already moved to value assets at current rather than historic cost (eg ETSA, GFCV and SECV). Similarly, the SECV and GFCV have introduced rate of return requirements to reflect the opportunity cost of capital. The SECV is also likely to be subject to surrogate Victorian equivalents for Commonwealth sales and company tax. In Tasmania, the recent introduction of the State Authorities Financial Management Act is intended to address these difficulties. The adoption of the corporatisation model outlined in Chapter 5 would require that public utilities meet rate of return targets, value assets in current cost terms, pay all government taxes and charges and generally operate along the lines of private sector organisations. It would help ensure that appropriate costs are borne by authorities and that production is undertaken efficiently.

The corporatisation of all public electricity and gas utilities at the earliest possible time would also provide a better basis for establishing the revenue which is required to cover the efficient costs of supply, and so facilitate the introduction of improved pricing practices.

Tariff structures to reflect costs

Efficient pricing requires that tariffs accurately reflect variations in the cost of supplying different users (having regard to the costs of obtaining information and administering the system). Most existing pricing practices fail to do so.[1] The magnitude of this pricing inefficiency is indicated by Table 92. This shows cross-subsidies (differences between the cost of supply to, and revenue from, consumer groups) estimated by the SECV/DITR in Victoria's ESI for 1987-88.

[1] The need to depart from strict marginal cost pricing – through Ramsey pricing – to avoid the loss making dilemma of a regulated natural monopoly is recognised.

Table 9.2: **Estimated levels of cross-subsidies in electricity supply - Victoria: 1987-88**

Customer class	*Total revenue 1987-88*	*Cross-subsidy*[a]	
	$m	*%*	*$m*
Domestic	725.5	-24.4	-177.0
Community Service	13.4	-2.7	-0.4
Commercial & Industrial			
Small	464.8	+34.1	+158.5
Medium	276.1	+25.9	+71.5
Large	244.0	+12.7	+31.0
Farm	47.6	-120.0	-57.1
Public Lighting	35.5	+10.4	+3.7
Smelters	146.1	0.0	-
Other HV Supply	210.4	-14.2	-29.9

a A minus sign indicates the customer class is paying less than its cost of supply. A plus sign indicates that the class is paying more than its cost of supply.

Source: Derived from SECV/DITR (1989, p. 67).

In addition to cross-subsidies between classes, there are also significant cross-subsidies within classes. For example, the Tasmanian Government said:

> ... in the present retail tariff structure supply charges recover only a relatively small proportion of fixed costs, with the energy charge making up the balance. This is a form of cross-subsidisation within the retail sector from large to small users ...

The failure to reflect costs stems, in part, from government controls and constraints, such as CSOs and price ceilings. While some may be justified to restrain abuse of market power, most have been imposed for social and political purposes. Although this makes it difficult for utilities to act autonomously, some are presently addressing the problem. The ETSA, SECV and ECNSW, for example, are currently restructuring tariffs to improve cost reflectivity. Although some participants expressed support for restructuring tariffs to reflect supply costs more accurately, their support was subject to considerable qualification. The Tasmanian Government, for example, supported restructuring:

> ... subject to the Government's policy objectives with regard to economic development, the creation of employment and social justice.

At the draft report hearings, the Tasmanian Government representative confirmed that electricity prices to some Tasmanian users have been subsidised to create employment. The Victorian Government also affirmed its objective to minimise cross-subsidies, but within the constraints of maintaining uniform tariffs, a simple tariff structure and price stability. Another impediment to cost reflective tariffs is the tardiness of implementation. ECNSW and the LGEA of New South Wales noted that the New

South Wales Government has a policy aim of reducing cross-subsidies within 5 years. The Victorian Government stated that it expects it to be 10 years or so before crosssubsidies between classes are corrected. However, with corporatisation, there would appear to be little reason why some of the present inadequacies could not be addressed in the near future.

Consumer classes

All utilities group consumers into classes (usually according to type of end-user) and establish a different tariff for each class. However, the costs of electricity or gas supply do not vary on the basis of end-user. Rather, they vary with, for example, the level and time-of-use of consumption, location, voltage, pressure and quality of electricity or gas. Differentiating tariffs by consumer classes, rather than by the characteristics of each users' consumption, can target the ‘wrong’ variable. It can result in a poor approximation of actual costs incurred.

AGL noted that end use is a practical way of differentiating between load characteristics. However, the LGESA of Victoria expressed a preference for classifying customers by load shape rather than by end user class. Similarly, the SECV noted it is moving to tariffs based more on load profiles. The Commission recognises that changing the basis for classifying users is not without difficulties. The Tasmanian Government, for example, referred to impediments (at least in the short term) in measurement, monitoring, possible customer relations difficulties and associated administrative costs.

While for administrative simplicity some grouping of users will be necessary, the Commission considers the existing categorisation should be reviewed so that, if inconsistencies are found, categories can be employed which better reflect load characteristics than do current end-user categories.

Uniform tariffs

The application of uniform tariffs ignores differing electricity and gas supply costs. For example, tariff uniformity across a state does not account for the specific costs associated with distance from point of supply (eg larger capital requirements for longer

transmission lines or transmission losses). As a result, some consumers face prices greater than the costs they incur. These users subsidise the rest. This government policy is pursued by electricity authorities in all states/territories and by public gas reticulation utilities.[2]

Allocating costs stemming from distance may require information on a different basis from that currently collected. However, this should not represent an overwhelming

[2] In New South Wales, wholesale electricity tariffs are uniform throughout the state to distribution authorities, but there is some variation in retail tariffs.

barrier to its implementation. To some extent it is already done by TPA: its tariff for the ACT reflects incremental capital costs attributed to the Territory.

For electricity, some participants (eg SECV) claimed the distortions involved are minor. ECNSW stated that the distortion arising from uniform tariffs is very small, and results in a less than one per cent increase in price to the retail metropolitan region. However, given the concentration of population in Sydney, this would represent significantly greater subsidisation of tariffs for users in other areas. Indeed, at the draft report hearings, the Electricity Council of New South Wales stated that, in relation to Prospect County Council:

> ... we have a very large area of supply, diversified between heavy industrial, urban areas and very widespread rural areas. Now, the cost of supply to those fringe rural areas is in the order of three, four, five times as much as to the urban areas.

For gas, the South Australian Government gave an indication of the importance of tariffs reflecting actual cost of supply. It noted that:

> SAGASCO tariffs, unlike those of ETSA, vary with geographical location, reflecting the substantially higher costs associated with supply of natural gas to rural townships. Nevertheless, the tariffs set for these regions do not recover the direct costs of supply.

The Commission considers that state-wide uniform pricing should be discontinued. Electricity and gas prices should vary between regions in accordance with justifiable variations in the costs of supplying those regions.

Tariff structures

Under block and flat rate tariffs, the prices charged are uniform regardless of, say, timeof-use. Accordingly, it is unlikely that charges will correspond to the actual cost of supply. The exception is in a hydro system, such as Tasmania, where supply costs do not generally vary significantly over the short term.

Access charges and block tariffs for gas have similar shortcomings. Gas utilities appear reluctant to collect the full fixed costs of reticulation from consumers through a supply charge or access fee. For example, only Victoria and South Australia apply an access fee for domestic consumers. Moreover, in both cases the fee does not cover all fixed costs.

For block tariffs, the pricing structure adopted by most gas utilities is based on consumption over a bimonthly or quarterly billing period, and hence cannot reflect load factor savings or costs associated with daily or hourly peaks. The only utility which attempts to peak load price for seasonal fluctuations is the GFCV. It charges residential customers on the basis of a two tier increasing block tariff, reflecting the increased cost of winter supply.

Demand tariffs focus only on the demand side and do not reflect actual supply conditions and costs. For example, when supply outages place the system at risk, a demand tariff gives no incentive for sites to trim their load. It can also provide perverse incentives. If industrial users on a demand tariff peak during off-peak periods, there is an incentive to shift load either forward or back to avoid exceeding their maximum demand limit. However, such load shifts add to system peaks and to costs.

Bulk supply tariffs should further recognise time-of-use. At present, time-of-use is applied in New South Wales and in Victoria (to the 11 MEUs). However, the New South Wales tariff incorporates only three broad periods. The usefulness of the Victorian off-peak tariff was criticised by the City of Box Hill Electricity Supply because:

> ... the only off peak incentive refers to a [residential] $/customer return of $40/annum and is not related to any other off peak usage.

Greater differentiation is required if costs are to be reflected accurately. In the case of electricity in Victoria, bulk prices should be determined with reference to costs of supply (allocating generation and transmission costs) rather than on the basis of fixed margins for end-use categories. Where transmission and distribution bodies are separate, energy discounts and premiums around an agreed contract level could be offered by the transmission body. This would provide a financial incentive for load management by distribution authorities when transmission or generation constraints apply.

Improved wholesale electricity tariffs are crucial for improvements in retail tariffs. As the New South Wales Government noted:

> ... the existence of a cost reflective BST creates its own pressures for retail tariffs to become more cost reflective, particularly since wholesale electricity purchases represent a large proportion (more than 70 per cent) of retailers costs.

The Commission considers it essential that existing tariff arrangements for bulk supply be altered to better reflect costs.

Participants (eg the ECNSW and the Electricity Council of New South Wales) drew attention to the increasing application of time-of-use tariffs. However, existing time-of-use retail tariffs are generally optional. As a result, only those users who will benefit (not those who would be penalised) are likely to use them. Moreover, time-of-use periods and tariffs are usually fixed in advance - there is no flexibility in the short term to alter rates or vary the times of rate charges. Because there are very few rating periods, current time-of-use tariffs are also greatly simplified. Thus, they can only track crudely the fluctuations in supply costs over the course of a day or at different times of the year.

Advances in electronic metering and monitoring (such as the meter developed from cooperation between Nilsens and SECV) have made more cost reflective tariffs feasible for most non-residential customers. In this regard, the New South Wales Government stated:

> The ESI could 'lock up' around 50% of its energy sales on time-of-use tariffs with the installation of meters to approximately 1% of its customers.

For domestic customers, the situation is less clear. The SECV is experimenting with more detailed residential time-of-use tariffs (the 'WINNER' tariff) and ECNSW has a number of trials for domestic use in progress. However, in this area some problems are still to be overcome, as indicated by the ACI EW claim that, at present, the benefits from new metering of domestic users do not outweigh the extra costs involved.

Notwithstanding present limitations for domestic users, these advances should allow the introduction of more flexible tariffs and tariffs for some markets previously not differentiated. Although more applicable to the ESI, such advances are also relevant for gas. Active load control and two-way communication between supplier and customer is becoming more economic and offers opportunities for multi-time-sector tariffs and interactive customer/supplier pricing (SECV/DITR 1989, p. 65). This flexibility offers scope for providing premiums/discounts based on the quality of power supplied and extending present peak and interruptibility tariffs. In Australia, there are presently a few contractual interruptibility arrangements with some large users (eg with aluminium smelters, chemical plants and water authorities), but such tariffs are not generally available.

Improved monitoring and metering also has implications for more accurate allocation of fixed and variable costs. Accordingly, improved information should be reflected in more appropriate supply charges and variable (marginal) costs where two-part pricing is appropriate.

While contract sales to major customers can better reflect supply costs than standard tariff arrangements, they can discriminate against other customers and hide from public view and scrutiny the workings of a large part of the market. The RCS was particularly critical of some confidential deals made by QEC. It stated:

> The deals are conducted in secret but at public expense. The public would probably be outraged if they were aware of the level of these "subsidies" but they have no way of knowing the beneficiaries of these special deals or their contents.

In this regard, the GFCV determines contract terms and conditions according to a formula as a conscious attempt not to discriminate between contract customers. At the draft report hearings, IES called for transparent pricing, with the basis for charges clearly understood by all and seen to be non-discriminatory. This is currently the case, for example, in the United States for some contract tariffs. IES considered that:

> Confidential price arrangements contribute nothing to an efficient outcome unless the players are operating in an open, fully competitive environment (in which case confidentiality is not an issue). In a less than competitive environment, confidentiality allows arbitrary price discrimination to be practised.

In the Commission's view, the likelihood that ‘special’ tariff arrangements negotiated between utilities and large users will conflict with the public interest would be substantially reduced by corporatisation. Implementation of the changes in industry structure and ownership proposed in the preceding chapters would further reduce the possibility of inefficient charging.

Standby tariffs have been criticised as being unnecessarily high. As supply systems have become larger and more diverse, there is less need to maintain additional standby capacity dedicated for self-generators. It is highly unlikely that all of it will be called upon simultaneously, and simultaneous with failures of utility generators (except for special cases such as where the co generator is large in proportion to grid capacity). The appropriate yardstick should be the fluctuations arising from all the loads and generators in the system and the probability of that happening at the system peak. Standby is already provided in the supply system to meet unexpected loads and system outages, and the cost is built into standard tariffs. Charging for it on top of existing tariffs is, in effect, double counting and unduly penalises co generators. Standby tariffs should therefore be removed and replaced with standard tariffs. In special cases, where a co generator is large or their generation coincides with seasonal peaks, standby charges may be warranted. These should reflect the capacity set aside by a utility to provide power and the probability of an outage requiring the use of that capacity.

The Commission recommends that bulk and retail tariffs be based more closely on supply costs attributed to the characteristics of consumption (eg location, size of demand, time-of-use, voltage, reliability). This would involve increased reliance on time-of-use tariffs, greater flexibility in the application of such tariffs (eg the ability to vary charges and rating periods in response to changes in demand and/or supply conditions) and less reliance on demand tariffs. It would also require adjustments to access charges to reflect a more accurate allocation of fixed costs. Standby tariffs applicable to private generators should generally be abolished. However, in special cases, standby charges reflecting capacity set aside and probability of use could be appropriate. The Commission also recommends that priority be given to areas in which early gains are achievable.

9.4 Longer term pricing strategies

With corporatisation, most of the changes considered above to improve pricing could be implemented in the near future, say the next 12 months. Although the proposed modifications would relate prices for electricity and gas more closely to supply conditions, prices for many market segments would still be essentially determined by administrative means. In contrast, most goods and services sold in Australia are determined by market forces. The Industry Commission contracted a study for this inquiry (by IES) to consider how more efficient pricing could be achieved. [3] Some proposals in that study are embraced in the changes outlined above. Other proposals

[3] Copies of the IES study are available from the Commission on request.

require major changes in the competitive environment for electricity and gas, and are the subject of this section.

IES contends that prices will only be efficient if they are market driven. This would introduce greater volatility to pricing. To allow management of this volatility, IES proposes the establishment of forward market trading. Pricing and investment outcomes would be determined on the basis of signals emerging from such a system.

Under an open market for electricity, a short run market price would be set by trading in electricity among a wider set of industry participants, including distribution bodies and private generators. The market price would reflect the value of electricity determined by demand and supply.

Neither short run prices nor forward prices need be set by any centralised body. However, a centralised body would need to be responsible for managing the market arrangements and ensuring that all market participants are held to their obligations.

IES suggests a more open market environment will require: splitting generation from transmission, planning and other functions; converting the Snowy Scheme into an independent commercial enterprise; converting power stations to independent profit centres - initially trading with the central transmission organisation; allowing distribution bodies to trade directly with power suppliers in the open market; opening up the market to potential independent suppliers of power; and allowing larger consumers access to open market trading facilities and to wheel any purchases through the distribution system.

The major components of the system proposed by IES are:

- forward contracts and futures;
- options; and
- arrangements for maintenance scheduling and investment.

The IES proposals in relation to market pricing, about which the Commission sought comment from participants, are briefly summarised below.

Forward contracts and futures

A forward contract is an agreement between a buyer and a seller to trade a set quantity of a commodity at a fixed time in the future for a set price. In the case of electricity, whose demand and value can be expected to fluctuate at short notice, the time could be defined as a particular hour or half hour in the future. Forward contracts in electricity will normally be traded as packages corresponding to complete profiles of seller output or buyer load.

In the time interval of interest, suppose a seller and a buyer agree to trade a quantity at a given price. When the time arrives for the seller to deliver, the trade is made on the agreed terms. If the seller has surplus capacity, that surplus can be sold on a short term (spot) market. Alternatively, if the seller produces short of the agreed contract, he can make up the difference from the short term (spot) market. As with other commodities traded in this way, certain deposits or guarantees would have to be lodged to ensure fulfilment of the obligations of the contract. These obligations are fundamentally financial, as it should always be possible to make up the delivery quantity from the spot market, albeit at a price.

If the amount consumed deviates from the contract, the price paid (or received) for the difference is simply the current spot price. Thus, the efficiency of short run pricing is retained with forward contracts. For example, if the spot price is very high at this time the consumer will have an incentive to sell back some or all of the contract on the spot market, provided the cost of foregoing consumption at this time is not too great.

There are benefits to be gained by allowing contracts such as these to be tradeable at any time. This can be done if a forward market is maintained in which supply and demand dictate forward prices in the same way that they dictate short term prices. To do this, a computerised trading system would be required for each geographically separate market. Load and price profiles representing bids and offers would be lodged to and matched in the computer. This matching process would set the amount traded and market price for each forward trading interval. After one or more 'trial rounds' to allow participants to adjust their positions, the trades would be finalised. Alternatively, buyers or sellers could enter the market on an immediate 'best available deal' basis.

Under such a forward trading system, buyers or sellers would be indifferent to who they were dealing with. Their obligations from a forward trade would be to the market, not to any particular trading party. The central trading system would record these obligations and the trading organisation would be responsible for ensuring that they are met. As with other forward markets, certain securities would need to be lodged by traders to guarantee their market performance. This is a central requirement for such a trading system to work.

A trader may profit, break-even or lose from the purchase and subsequent sale of a forward contract. Even if a trader loses a little on a forward contract, the contract has still served its function in the management of risk.

Futures contracts could be used to cancel out the effect of spot price volatility if the appropriate contract amount is purchased. Futures contracts would allow transactions to be conducted completely separately from the spot market or the bodies actually engaged in physical trading. This has certain organisational merits. It means, for example, that a forward trading organisation could exist completely independent of all the market players, including organisations responsible for managing the grid. The only requirement is that a market-determined short term price be available so that all outstanding forward contracts can be settled at spot time.

Options

Some plant which operates only at times of system stress may not find forward contracts very useful. Examples are plant and load management options whose operating costs are very high (ie greater than any forward prices, which are expected or average values of future prices). In such cases another financial instrument, the option, can allow both buyers and sellers to manage their risk.

An option to sell is an agreement whereby a buyer pays a fixed premium for the right to buy a fixed quantity of electrical energy at an agreed strike price at some future time. When that time comes, the buyer will not exercise the option if the spot price is below the strike price; he will go to the spot market. However, if the spot price is greater than the strike price he will prefer to exercise the option by paying the agreed strike price.

Now suppose the seller chooses a strike price equal to his unit production costs. The market will then determine the appropriate premium. In essence, buyers must come to a view of the likely extent and duration of spot prices exceeding the strike price at the nominated future time. Once the premium is negotiated, the seller has gained an assured income (the premium) in exchange for two possible outcomes. If the option is not exercised, no further costs are incurred or income received. If the option is exercised, an additional income at the strike price will be received but he is then obliged to deliver, which will use up the additional income received. He should be indifferent between these two outcomes. Of course, if he fails to deliver he must go to the spot market to fulfil his obligations, which may be expensive. If the option price (premium) is high enough to cover investment costs, a potential supplier of standby plant could lock in a return on his investment, provided the plant performs adequately when required to deliver.

The buyer's position is a little different. In exchange for the agreed premium, he has capped the risk of very high future prices at the agreed strike price.

Maintenance scheduling and investment

A generator owner requiring to do maintenance in the weeks, months or even years ahead must balance the urgency of the repair with the loss of income incurred during the maintenance outage. The forward market provides a mechanism for this to be efficiently planned. The operator would look for a period of low prices in the forward market which also meets the maintenance requirements. He would then buy electricity to cover his sale contracts and schedule the maintenance for this time. This strategy ensures that the best opportunities for profit are not missed. It also ensures that the planned outage occurs when the system needs his output least (ie when prices are low).

When established, the forward contract market would reflect the planned maintenance schedules of the various sellers and buyers. The trading activity described would take place when one participant wishes to change his own schedule. Such a change would be marginal for the system as a whole, so the forward price schedule would be unlikely to provoke a wholesale shift in other schedules.

How would investment occur under a system of forward markets? Consider first the simplest case of investment in base-load plant. The investor could ignore the forward market or use it simply to form a view of likely future prices. A typical scenario for the evolution of prices could be as follows. Short run and near term future prices might reflect short run production costs of coal-fired plant, with little or no prospects of supply shortages. Such low prices would not and should not support a new base-load plant. In future years there would be increasing likelihood of more expensive plant being required to run, as well as occasional supply shortages and periods of elevated selling price as a result. At some future year, taking into account that others might be reaching the same conclusion, expected prices would cover all operating and capital costs and a commitment to the plant would be made for commissioning in that year.

It is important to note that short term forward prices take account of the value of energy not served in the case where blackouts apply, or the need to induce load management from certain consumers. No incentive to meet reliability standards, other than price, is required. Actual prices and returns for the new plant may turn out better or worse than this original assessment. Because of this high risk, the investment would best be supported by first selling the plant's output in the forward market. Two approaches are possible. The investor could first look to the forward market to find a buyer or buyers willing to purchase the output from his proposed plant at a price sufficient to cover long run (operating and capital) costs. If no such buyer was found, he could place an offer on the forward market to sell power at his long run cost, plus any margin he though the market might accept. In any case, the bidding system would match bids and offers to determine the going price at that time.

Why would a buyer, perhaps a distribution body, make a commitment to purchase the block from that time? The buyer would also see low short run prices, with prospects of increasing episodes of shortages at some time in the future. This uncertainty would tempt most buyers to secure a firm contract at the best going rate in the forward market. Why would long run prices not apply in the medium term? Under the scenario we have assumed, there would be a predominant view of a prevailing capacity surplus and short run prices lower than long run costs in the medium term. Thus, a buyer should have no trouble finding a seller at a price something less than long run costs.

Competitive gas pricing

A fully developed gas market would require a number of gas producers and a number of gas purchasers operating in a competitive market. In the US, the natural gas industry now meets this requirement, with a complex network of pipelines and many producers and customers, Since deregulation of gas prices, the market has been developing along commodity market lines, with spot pricing common and a futures market developing.

IES suggest that, at this stage, these conditions do not apply in Australia, and cannot apply until all the major gas markets are linked by pipeline.

Response to proposed longer term pricing strategies

Little comment was received on the long term pricing strategies proposed by IES.

The Tasmanian Government supported the introduction of the IES proposals in relation to market pricing. It stated:

> There is merit in the concept of establishing a commodity market, using forward contracts, futures and options for the supply of electricity energy to major users. A competitive market would ensure that future electricity sales went to those industries that placed the highest value on the energy.

A paper attached to the submission by the University of New South Wales - Department of Electric Power Engineering - saw the introduction of futures trading as a desirable step for Australia's electricity industries. The authors argued that exposing decision makers to the risks associated with their decision options would lead to more efficient outcomes. At present, supply authorities are exposed to less risk than consumers, leading to discrepancies between the payback criteria used on the supply and demand sides of the industry and a bias towards supply-side investment. The paper stated that:

> Financial instruments are commonly used in conjunction with markets (e.g. futures trading) to allow aggregate views of the future to emerge ... and to provide a mechanism for risk sharing. Such instruments would have an important role in coordinating operating and investment decision in network-based trading.

However, most of the limited comment received expressed reservations and qualifications on the introduction of any changes. The ESAA, for example, was unconvinced of the practicality of ‘spot pricing’. Along with ECNSW and the Victorian Government, it expressed the sentiment that it would, in practice, be feasible only for very large players for whom the metering and communication costs would not be excessive. However, confining it to large players would still include the existing generators and distributors, as well as major industrial customers.

ECNSW's reservations included the concern that transaction costs associated with operating a flexible pricing system would partially offset the benefits of that system. Notwithstanding this concern, existing control systems already monitor discrete incremental costs for load scheduling. Existing revenue metering also operates for discrete periods, with 15 minute averages commonly used. Furthermore, advances in computing and communication are increasingly capable of addressing this problem.

The ECNSW and the Electricity Council of New South Wales expressed concern that a system of spot and forward pricing would bias the next investment in plant towards short lead time plant. However, such a development may not be a distortion. It would help correct the current bias to long lead time, high capital cost plant. Investment in short lead time plant would recognise that the risks of investment in long lead time plant in an uncertain world are real. Such investment would not become excessive as a clear opportunity for large scale plant (with operating cost savings) would eventually appear in the forward market.

Recently it has been reported that the newly privatised United Kingdom ESI is seeking expressions of interest from consulting firms to advise it on the establishment of an electricity futures model.

9.5 Summary of proposals

Present pricing practices in the electricity and gas supply industries do not fully recognise economic costs of supply, nor reflect accurately costs. While utilities are addressing parts of this problem, more encompassing changes are needed to improve pricing efficiency. There are areas where early action is practicable which would lead to significant efficiency gains. To this effect, the Commission recommends that:

- electricity and gas utilities recover the full economic cost of supply in their tariffs;
- bulk and retail tariffs be based more closely on supply costs attributed to the characteristics of consumption (eg location, time-of-use, reliability); and
- standby energy tariffs applicable to private generators generally be abolished.

These recommendations are concerned primarily with administratively improving pricing. If improved pricing efficiency is sought through market disciplines, this would require changing the competitive environment of the electricity and gas supply industries. The Commission considers that this would most appropriately be achieved by adopting its proposals set out in the preceding two chapters. In these circumstances, the development of pricing mechanisms, such as those outlined by IES, could increase flexibility and promote the development of a competitive industry structure.

10 LOAD MANAGEMENT AND ENERGY CONSERVATION

Load management and energy conservation are initiatives by utilities and governments which can, and have, improved the efficient use of energy. These initiatives are somewhat negated by other government policies which induce inefficient energy pricing and thus inefficient energy use. Furthermore, there is a danger that without proper regard for the commercial objectives of utilities or the needs of energy users, some load management and energy conservation initiatives may reduce the efficiency of energy supply and the benefits derived from energy use. The benefits and costs must be carefully assessed Utilities should only be involved in those initiatives that are consistent with their commercial interests. Beyond this, the role of governments is dependent on identifying cost effective measures to address market or institutional failures in energy markets.

This chapter assesses initiatives by governments and energy utilities to enhance the efficiency of the supply and use of energy. The principle of least cost planning is examined, as are demand side management (DSM) policies and decisions relating to the use of alternate energy sources, such as renewable energy. Details about the DSM policies of governments and utilities, and issues concerning their application are also examined in Appendix 12.

10.1 Least cost planning

The principle of least cost planning, sometimes also known as integrated resource planning, has been developed since the 1970s. In essence, it is a planning process to determine whether future energy needs can be best met by increasing supply or by employing conservation and load management options to contain growth in demand. In some parts of the United States, the planning process has been widened to allow 'all-source bidding', where tender arrangements allow proposals for electricity supply from independent power producers or cogenerators to compete with proposed conservation projects.

Associated with, the development of least cost planning has been a reassessment of the role of the energy utility, with a renewed focus on meeting the needs of energy users. In some quarters, utilities are seen no longer simply as suppliers of gas or electricity. Increasingly, utilities are viewed as suppliers of energy services

This has been prompted by the realisation that consumers do not simply want so many kilowatt-hours of electricity or megajoules of gas. They want their computers or electric motors to operate, food cooked and rooms to be at a comfortable temperature and well lit. Therefore, energy users want more than low cost energy; they also want an efficient service.

Utilities have developed demand side management programs to determine what might be the needs of energy users and to develop initiatives to meet these needs. Demand side management programs consist of two main elements, load management and energy conservation initiatives:

- load management options (eg time-of-use charges and interruptible supply contracts) seek to alter the time at which energy is used (‘valley filling’ and ‘peak clipping’) and so spread demand more evenly over the course of a day or week; and

- energy conservation initiatives, such as energy advisory services, incentives for using energy efficient technologies, appliance energy labelling and minimum performance standards, attempt to reduce the amount of energy consumed by users and, thus, the overall level of demand.

Internationally there is a diversity of views on the extent to which utilities should promote improvements in the efficient use of energy. Generally it is agreed that utilities should undertake initiatives which are consistent with both their commercial interests and the interests of society. However, questions arise as to whether a utility should undertake initiatives which can be shown to be in society's interests, but are not in the commercial interest of the utility. Some argue that such initiatives would be more appropriately undertaken by the government, while others contend that utilities should be required to undertake them.

This diversity of views was reflected in the papers presented to a 1988 IEA workshop on electricity conservation. In summarising the workshop's proceedings, Hirst (1988) noted that participants agreed that:

- The efficiency of converting electricity into useful services has improved over the past two decades.

- A large potential exists for further improvements in end use efficiency.

- Prices should be set as close to economic costs as is feasible.

However, there were a number of issues on which participants could not agree:

- Is economically efficient pricing sufficient to ensure optimal adoption of cost effective demand side measures and practices?

In promoting energy conservation, should utilities either adopt a broad social view or should they attempt to minimise prices, with governments accepting responsibility to overcome non-price market barriers?

Similarly, during the course of this inquiry, participants expressed diverse views on the role of utilities in promoting the efficient use of energy. The SECV argued that:

> ... some conservation programs will result in benefits to the SECV but, with long run marginal cost likely to remain below average cost for most classes for some time into the future, many will not be commercially attractive. Programs in this category should be undertaken if and only if they provide a least societal cost means of balancing supply and demand for energy services.

The Tasmanian Government stated:

> ... energy utilities should not be required to pursue energy conservation objectives which cannot be economically justified.

It went on to argue that the government itself, in contrast to the utility, may choose to subsidise energy conservation measures for disadvantaged customers.

On the other hand, the Australian Conservation Foundation (ACF) considered that energy utilities should aim to:

> ... minimise the cost of energy services to the consumer in a non-discriminatory manner, whilst minimising the environmental impact of energy supply. These dual objectives can only be achieved through the integration of supply and demand-side options and by incorporating all environmental, as well as economic costs of supply into energy pricing structures.

This chapter addresses these diverse views by examining more closely the role of utilities, governments and users in influencing the efficient use of energy. Subsequently it examines a number of factors which are frequently said to impede the efficient use of energy.

10.2 Role of users, utilities and governments in load management and energy conservation

Governments, here and abroad, have been attempting to improve the efficient use of energy. Energy utilities have played a major role in implementing these policies. In Victoria, for instance, the SECV is statutorily required to implement the Government's energy conservation goals and must advise and assist customers in energy conservation. The SECV will spend $55 million over 3 years on DSM initiatives.

Some of the programs which governments have requested their utilities to undertake are quite clearly in the utility's commercial interest. For instance, some energy advisory services may improve the efficient use of energy and allow an electricity or gas utility to maintain sales in the longer term by ensuring that users do not switch to alternate energy sources (eg substitute from electricity to gas heating). Other advisory services may be offered on a fee-for-service basis. Such services may, in their own right, represent a commercial opportunity for a utility. For example, the ECNSW sees a role for utilities in:

> ... providing, on a commercial basis, the advisory service and equipment which the customer needs to improve efficiency.

Other DSM activities may be commercially attractive for a utility because they reduce supply costs. For instance, electricity utilities may offer rebates to induce 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.

However, some energy conservation initiatives may be neither in the commercial interest of a utility nor in the interest of all energy consumers. For instance rebates or ‘give-aways’ of energy efficient appliances - if successful - may reduce utility revenues by more than they reduce utility costs. While a utility can compensate for this by increasing prices, this strategy requires non-participants to subsidise the energy conservation initiative. The SECV suggested that programs which are not in its commercial interest:

> ... could be treated simply as a Community Service Obligation and their costs/benefits separately identified as is the intention under the present arrangements during the Three-year DM Action Plan. Alternatively, they could be implemented through a commercial energy service company receiving income for them directly from Government for societal benefits actually delivered.

A number of participants who supported the adoption of least cost planning techniques by Australian utilities noted their apparent successful adoption in some overseas electricity supply industries. In particular, the profitability of energy conservation initiatives for the privately owned utilities in California was highlighted.

The Commission understands that much of this overseas experience cannot be easily transferred to Australian conditions. For instance, the regulatory cost associated with new generating facilities can be considerably higher in the United States than in Australia. In these cases, utilities in the United States undertaking DSM initiatives to reduce the growth in energy demand, can expect to reduce supply costs to a much larger extent than utilities in Australia. In California, strict controls have also provided a greater incentive for utilities to use renewable energy resources (eg wind and solar).

The extent of conservation activity by utilities in the United States is also influenced by other forms of regulation. For example, the operations of the privately owned utilities are tightly controlled by state utility commissions. Since the 1970s, these commissions have increasingly influenced the DSM activities of the energy utilities. For instance:

utilities in California are required to submit energy conservation plans to the California Public Utilities Commission, which takes these efforts into account when deciding upon a fair rate of return and in authorising new supply; and

- the *Pacific Northwest Electric Power Planning and Construction Act (1980)* only allows the construction of new generation facilities if all cost effective conservation measures have been installed. In fact, conservation initiatives are provided with a 10 per cent cost advantage over generation due to avoidance of transmission losses and the externalities associated with generation (Khawaja, Potiowsky and Peach 1990).

In addition, it is becoming more common for the regulatory commissions to approve price increases to allow utilities to earn a return on any expenditure on least cost planning initiatives.

Hence, the observed differences, between the United States and Australia, in implementing energy conservation initiatives can largely be attributed to differing supply conditions and the regulatory environment.

The experience of the energy supply industries in Australia has been one of poor performance, in part attributable to government requirements that energy utilities undertake non-commercial activities (see Chapter 5). Consistent with the Commission's rationale for corporatisation and the treatment of CSOs, energy utilities should not be required to undertake DSM activities which are not in their commercial interest. If, however, governments insist that utilities undertake non-commercial DSM activities, they should be separately identified and fully funded by the government. Otherwise they should be undertaken by some other government agency. This avoids the possibility of conflict arising between the commercial and non-commercial objectives which might compromise performance.

This then raises the question of what role governments have in altering the use of energy. The level and pattern of demand for most goods and services is generally a decision best left to consumers. This is because the consumer is the one who benefits and should therefore be in the best position to judge which pattern of consumption best suits his/her lifestyle or business activity. In these circumstances, energy users would generally adjust their pattern of energy consumption to improve their standard of living, in the case of households, or profitability in the case of firms. It is difficult to see why the consumption of energy should be viewed differently from the consumption of all other goods and services (eg the purchase of a motor vehicle, a restaurant meal, the choice of a holiday venue or curtains for a home), all of which have energy and environment implications.

However, if the signals consumers receive are deficient, the decisions they make will not result in the efficient use of energy. Two major reasons why this may be the case are: first, energy prices may not reflect supply costs and, second, supply costs may not reflect all costs (eg the cost of environmental damage). These two distortions fall into categories known as institutional and market impediments. Problems are also created if information is costly and consumers are not fully informed on the options available for meeting their energy needs.

A role exists for governments in overcoming these barriers to the efficient use of energy. One way for governments to address these problems is to legislate particular changes (eg to prohibit the use of relatively low efficiency appliances or to mandate particular standards, such as insulation standards). As explained later (see Section 10.3.4), this approach raises the real possibility of diminishing the benefits consumers receive from their disposable income, in particular, the benefits derived from energy use. The Commission considers that this risk can be avoided if, as far as is practicable, governments and utilities concentrate on providing users with the correct price signals on the cost of alternate energy services. This would involve removing institutional impediments which result in energy charges not reflecting current supply costs, including costs which are external to the supply and/or use of energy (eg pollution costs) and providing information where proven deficiencies are identified. These are all areas where governments, rather than utilities, can influence, for the better, the judgements consumers make on the use of energy. These issues are examined in greater detail in the following section.

A number of submissions on the draft report were critical of the Commission's proposal that utilities should only engage in those DSM activities in which they have a commercial interest. The Commonwealth Department of the Arts, Sport, the Environment, Tourism and Territories (DASETT) argued that the:

> recommendation rests on an unsubstantiated assumption that the array of programs which constitute demand-side management ... are all non-commercial so far as energy utilities are concerned.

The ECNSW argued that the Commission's proposal:

> contains an implicit assumption about commercial viability which is too narrow. Specifically, the Draft Report does not recognise that all programs which provide societal benefits can be commercially viable if the benefits are distributed among the various parties so that all parties benefit.

Such criticism may be attributed to a misunderstanding of the Commission's proposal. The Commission does not consider that all DSM programs are non-commercial. On the contrary, the Commission recognises that there are considerable opportunities for energy utilities to become involved in the supply of energy services. The Commission does not propose to give a prescriptive list of those services which should be provided by the energy utilities. The identification of commercial services should be determined by utilities themselves having regard to their particular markets and costs. These factors differ between electricity and gas utilities, across geographical locations, and over time.

Furthermore, the Commission also recognises there are a number of institutional and market barriers which have inhibited the demand for, and supply of, energy services. The Commission considers that the best way to meet the community's energy needs is for governments to remove these barriers through cost effective intervention. This would allow normal market forces to provide those energy services which are highly valued by consumers, including more energy efficient technologies and practices. The Commission is therefore supportive of the least cost planning principle to the extent it encourages utilities to meet consumer needs (based on their willingness to pay) and involves government acting to remove barriers to efficient energy use.

However, the Commission is not supportive of the least cost planning principle in as much as it attempts to prescribe how the needs of individuals and groups of energy users can be best met; in particular, when it focuses on cost minimisation alone. Such a focus potentially ignores the tradeoffs that exist between the benefits associated with consuming energy services and lower energy costs. For example, a least cost focus may ignore the premium some consumers place on security of supply (eg hospitals) and the consumption of energy during peak periods. Least cost planning may also ignore the tradeoffs that exist between energy cost and the non-energy attributes of an appliance or building (eg large windows may increase the advantages of a good location, but reduce the thermal integrity of the building).

By specifying a clear distinction between the roles of utilities and governments it is clearer what the objective of a load management and energy conservation strategy should be.

The objective of load management and energy conservation initiatives should be to ensure that energy prices accurately reflect supply costs (including environment costs) and to remove any significant institutional or market impediments to the efficient use of energy.

The Commission considers that the appropriate role for governments is to remove any institutional impediments and address any significant market failure which limit the efficient use of energy, provided it can be demonstrated that net benefits would result.

Energy utilities should engage in only those demand side management activities in which they have a commercial interest, such as load management and some advisory services.

10.3 Institutional impediments and/or market failures

Several participants in the inquiry, including the New South Wales Government, DASETT, the ACF and the Rainforest Conservation Society, argued that a number of factors inhibit the efficient use of electricity and gas. Some are institutional, the side-effects of government policies implemented to address other concerns (eg state development), while some are the result of market impediments to the efficient use of energy. The barriers which have been highlighted include:

- government policies which cause utilities to under-price energy;
- inefficient tariff structures;

- environmental damage which is ignored in assessing supply and demand options; and
- information deficiencies which result in consumers not being fully aware of the options for the efficient use of energy.

The view that energy is not being used efficiently and that there is an underinvestment in energy conservation is claimed to be supported by a number of studies, undertaken in the United States, of the implicit discount rates associated with residential investments in energy saving technologies (see Train 1985). These studies indicate that, in general, consumers use higher discount rates than do utilities. However, these higher discount rates may simply reflect that less well off households place a premium on current consumption. Further, the studies have not included all costs associated with investing in an efficient appliance (eg search and installation costs).

In Australia, as elsewhere, governments have adopted or examined a variety of different policy responses to help overcome these barriers. These include time-of-use pricing, advisory services, energy efficiency audits, appliance energy labelling, home energy ratings, minimum efficiency standards for appliances and buildings, incentive packages for cogeneration and renewable energy technologies, incentives for the use of energy efficient products (eg subsidised fluorescent light globes) and government grants for research and development of energy efficient and renewable energy technologies.

In examining the problems and assessing the appropriate policy response, the Commission has tried to identify the cause of perceived or real institutional or market failure, and subsequently to establish whether any clear gains can be achieved by implementing some remedial action.

In essence, the Commission considers that efficiency improvements are likely to be greatest if policies are directed at the cause of an impediment rather than at the symptoms.

The following discussion briefly comments on the barriers to efficient energy use listed above. A formal examination of these barriers is contained in Appendix 12.

10.3.1 Underpricing of energy

Major energy users rely on energy prices to assess the cost effectiveness of an investment in an energy efficient building/appliance or an alteration to their pattern of energy use. The importance of pricing in DSM programs was acknowledged by a number of participants in this inquiry. For instance, in its submission, the New South Wales Government recognised that for DSM programs:

> ... to be fully effective it would be necessary to have time-of-use marginal cost based retail tariffs.

However, the broad conclusion of the discussion of pricing in Chapter 9 was that the prices charged for electricity and gas do not closely reflect the economic costs of supply.

Therefore, users do not have the correct incentive to conserve energy or use energy efficient processes or appliances. A wide range of Commonwealth, State and Territory government policies actually induce inefficient energy pricing by public utilities and thus inefficient energy consumption. These include tax concessions, free loan guarantees, the provision of loans at concessional rates and, with a few exceptions, no rate of return or dividend requirements.

These policies conflict with the desires of some governments to promote efficient energy use. For example, the ACF argued that:

> Electricity grids have been extended in the rural areas of several States where remote area power supplies, such as solar voltaic cells or diesel-battery sets or hybrid systems, can provide less expensive electricity. The costs of these grid extensions have been funded directly by State Governments and/or urban electricity ratepayers who are unwittingly cross-subsidising rural electricity rates. Until recently, the cost of connecting rural homes to the grid was even tax deductible.

In contrast, private sector suppliers of energy services, for instance gas utilities, manufacturers and retailers of thermal insulation and solar heating technology, are required to earn profits to remain in business and are subject to sales and income tax and a range of other state and local government charges. Most public utilities are not subject to similar requirements and therefore have an unfair competitive advantage over private sector ‘competitors’, this advantage is reflected in energy prices.

The Commission considers it 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.

It is sometimes suggested that governments should subsidise energy efficient and renewable energy technologies to overcome pricing deficiencies and make them competitive with energy from traditional sources. However, this approach attempts to solve the problems created by the institutional impediments rather than to remove the cause of the problem. A number of factors mitigate against its success. First, it is unlikely that all of the distortions created by the impediment will be removed. Second, other distortions may be created if the solution is not carefully targeted. Third, this approach is administratively costly and can be inflexible to changing market circumstances.

For example, it would be virtually impossible to devise a set of subsidies which would compensate for commercial advantages favouring utilities. Subsidies to offset these advantages would have to be based on the energy rating of an appliance, differ between user classes (eg domestic and commercial), and between geographical location (eg rural and urban). To maintain the appropriate incentives, the rate of subsidy would have to be changed each time there are changes in the relative costs of supplying energy to the differing market segments. Since energy prices remain subsidised, this approach would maintain the incentive for users to over, or inefficiently, use energy appliances (eg leaving windows open in an air conditioned building).

In contrast, corporatisation, as outlined in Chapter 5, seeks to remove the cause of the problem. It emphasises the removal of commercial advantages or disadvantages that the regulatory environment confers upon public energy utilities. By removing the impediments themselves, corporatisation places publicly owned energy utilities on a more equal footing with the private sector utilities and appliance manufacturers. The advantage of this approach is that the incentives to the efficient use of energy can be improved without the need for a complex set of subsidies and certain other DSM programs employed to compensate for the institutional impediments that currently exist. These programs can then concentrate on addressing any market failures which may hinder the efficient use of energy or renewable energy technologies.

The Commission considers that governments should improve the incentives for the efficient use of energy through the removal of institutional impediments, such as requiring utilities to fulfil community service obligations and providing them with tax concessions. This approach is preferable to, and more efficient than, a piece-meal set of initiatives which attempt to address the outcomes rather than causes of problems.

Adoption of this approach would alter the incentives for energy users and utilities to engage in energy conservation. In many cases it will encourage energy conservation. However, in some cases, the incentive to engage in energy conservation could be reduced. For instance, the attractiveness of energy conserving activities for the SECV's commercial customers has largely been attributed to the higher prices these customers have faced in order to finance the subsidisation of other customer classes, eg domestic. Also, a number of utilities are involved in programs to encourage the use of high efficiency lamps. This can occur because the utility wishes to reduce energy demand in those customer classes whose energy use is subsidised. Thus, if these subsidies are eliminated, there could be some corresponding reduction in the incentive for the utility to implement an energy conservation initiative. However, in this case, there will also be an increased incentive for consumers to conserve energy; both in terms of their choice of an energy efficient building or appliance and in the way an appliance is used.

10.3.2 Inefficient tariff structures

Improving the signals for the efficient use of energy not only requires governments to ensure that utilities bear all costs, but also requires utilities to adopt pricing structures which more closely reflect supply costs. As discussed in Chapter 9, this is currently not the case in Australia. To a large extent, it is because governments require public utilities to fulfil, and fund internally, CSOs. However, deficiencies in tariffs caused by CSOs have been compounded by limitations in the tariff structures employed by utilities.

Load management initiatives can improve tariff structures by ensuring energy prices are more reflective of supply costs. In thermal electricity systems, the average cost of supply generally increases as the load increases. Thus, the cost is greatest during peak periods when relatively high cost peak load plant is operating. To reduce system costs, most utilities attempt to even-out demand through load management initiatives, such as time-of-use pricing. Interruptible supply contracts can be used to save capacity expansion that would be otherwise required to cover unexpected increases in demand or system breakdowns.

In Australia, the most common load management initiatives consist of off-peak hot water tariffs and, for large volume customers, time-of-use tariffs and interruptible supply contracts. Overseas, a more diverse range of load management options has been offered. For instance, Electricite de France has been able to improve its daily load factors through the use of a two-part tariff with a demand charge (for a subscribed demand controlled by a circuit breaker) and an optional time-of-use tariff.

In the United States, Southern California Edison introduced a residential load management plan in 1981. Each participant in this scheme chose a minimum usage level at which they could run their home. Normally, services are unaffected. However, if consumption exceeds the predetermined minimum level during a critical period for the utility, services will be interrupted through a remotely controlled device installed in the home.

The different range of load management options offered by utilities in Australia may be partly a result of lower costs associated with supplying peak load. As such costs differ between utilities, so will the incentive for utilities to adopt load management initiatives. For instance, AGL stated that, in New South Wales, the gas distribution system is not operating at full capacity and that, if peaks do occur, the demand can be met from the storage inherent in the system. Similarly, there is less need for daily load management for electricity in Tasmania because of the lower differences between peak and off-peak supply costs associated with a largely hydro-electric system.

However, for those utilities which face high costs to meet peak demand, current load management initiatives are deficient in a number of ways. First, time-of-use prices and interruptible contracts are limited to only a few end users or end uses (eg large customers or residential hot water). Second, the differentiation with time-of-use tariffs that does occur is limited to only two or three rates and does not vary (eg by season). Third, the price differential between the peak and off-peak periods does not fully reflect the differences in the cost of supplying consumers at differing periods of the day.

These deficiencies are partly caused by the incorrect specification of load management objectives. Focussing on smoothing out a load curve and unit energy costs, ignores the benefits that accrue to consumers from using energy at different times of the day. More correctly, the objectives of initiatives such as time-of-use pricing and interruptible supply contracts should be to signal clearly to consumers the cost of using energy at a particular time of the day/year and of maintaining reserve plant. Based on these prices, consumers can then choose that pattern of energy use which is most suited to his/her lifestyle or business activity. Some consumers will continue to prefer to consume energy during peak periods. For example, consumers faced with high energy prices at six pm in winter may still choose to cook dinner at that time, rather than two hours later, because it suits their lifestyle. To offer additional incentives to increase off-peak consumption (eg price below off-peak costs), to smooth the load curve further, would tend to reduce the efficient use of energy.

Some perceived shortcomings in tariff structures are due to the costs associated with extending flexible pricing arrangements to all users and uses. The New South Wales Government argued that priorities need to be established in broadening the availability of time-of-use pricing. For instance, fifty per cent of electricity sales could be placed on time-of-use pricing with the installation of meters to approximately one per cent of

customers. In Victoria, the SECV is attempting to overcome the costs associated with flexible pricing through the introduction of an optional arrangement whereby residential users can choose a flexible tariff if they pay for the metering conversion costs.

Flexible pricing arrangements will become more attractive to utilities, as increased competition encourages a more customer oriented approach, and to users, as technological developments reduce the cost of new meters.

The Commission concludes that load management should be implemented with the objective of enabling energy prices to reflect more closely supply costs. The incentive for utilities to adopt cost reflective time-of-use prices and interruptible supply contracts will improve with technological developments in metering equipment and the corporatisation of the energy supply industries. This will improve the efficiency of energy use.

10.3.3 Environment costs

Improving the efficient use of energy also requires governments to ensure that any external costs, such as environmental damage, are included in supply decisions. The electricity and gas supply industries' impact on the environment is varied and may derive from several sources, such as the construction and operation of electricity generators and of energy transmission networks, or from side-effects of the use of coal, gas or water to generate electricity.

One option which has often been suggested to address environmental issues associated with energy supply, including carbon dioxide emissions, is the encouragement of energy conservation, through the use of energy efficient appliances or construction of solar efficient buildings. DASETT argued that:

> ... in many cases a given reduction in environmental impact can be achieved at lower cost to society by means of investment in efficient energy using technology than by investment in cleaner energy production technology.

The Commission recognises that the adoption of more efficient energy using technologies and practices can reduce the environmental impact associated with energy supply. While this reduced environmental impact may even appear relatively inexpensive to achieve, this can be attributed to the existence of a number of barriers to the efficient use of energy. However, a strategy, such as that advocated by DASETT, which focuses on reducing the growth in energy needs will not in itself provide utilities with the incentive to develop, or adopt, ‘environmentally friendly’ supply techniques. The Queensland Government argued that such a:

> ... strategy for emission reductions is not likely to be effective for large scale emissions over extended periods.

A strategy which is likely to be more successful in limiting, at a lower cost, the environmental impact of energy supply is for governments to: first, adopt policies which remove the significant barriers to efficient energy use (as discussed elsewhere in this chapter); and second, to employ measures which impact most on those supply techniques which have the greatest detrimental effect on the environment. The effect of this strategy will be to stimulate efficient energy use while also providing utilities with the incentive to use renewable energy technologies, adopt more fuel efficient combustion techniques or convert to fuels with lower emission levels.

To date, environmental standards have been the preferred approach to limiting the environmental impact of energy utilities. The standards encompass planning and operating controls on the construction of power stations and transmission systems for electricity and gas (see Appendix 11). They may be either performance based and seek to limit the amount of a pollutant released into the environment (eg licences which specify the quality of waste water discharges), or they may be prescriptive and specify construction techniques or the installation of specific pollution abatement equipment.

Unlike energy conservation measures, environmental standards do provide incentives for energy utilities to use environmentally friendly supply techniques. However, in some circumstances they can impinge on the flexibility of a utility's operation and reduce their ability to meet environmental goals at minimum cost. This can occur if prescriptive standards, which specify how the utility will meet the environmental objective, are employed. More preferable, are performance standards which specify environmental limits and rely on utilities' knowledge of production techniques to minimise compliance costs and ensure compliance through monitoring procedures.

To date, environmental controls on energy supply appear to be established independently of each other and, to a certain extent, irrespective of compliance costs. For example, because of the new restrictions governing the construction of transmission lines, electricity utilities may choose to use more brown coal than opt for more efficient or lower carbon fuels such as black coal, gas or a renewable energy source. The net environmental result may be worse than would have eventuated if the controls on the construction of the transmission line had also taken into consideration, explicitly, the compliance costs, including environment effects.

Another possible example is the Commonwealth's policy to prevent, if necessary, the import of technology for a nuclear power generator. A number of States also prohibit the development of nuclear power stations. This policy appears to be based on an assessment of their gross environmental costs, even though nuclear stations also have environmental benefits (eg they involve no emissions of greenhouse gases). The Commission notes that many OECD countries, including Belgium, France, Japan, Sweden, Switzerland and the United States generate a significant amount of their electricity from nuclear stations.

The Commission recognises that, on current costs, a nuclear power station would be unlikely to be economic in Australia. However, it considers that, subject to appropriate environmental and other safeguards, the question of nuclear electricity generation in Australia should be determined by commercial considerations.

Alternate approaches, such as transferable emission rights and pollution taxes, offer greater scope for achieving reduced environmental impact at minimum cost. Controlling emissions through transferable rights amends, rather than radically departs from, standard-based approaches. Currently, licences place limits on emissions from either a single source (eg stack) or from a whole complex, thereby setting an upper limit on the emission of pollutants into a local environment. Tradeable emission rights schemes explicitly set these limits for a local environment and allow the differing industrial sources of pollutants to produce varying amounts of emissions, provided the limit is not exceeded. This issue is discussed in more detail in Appendix 12.

Not all of the environmental impacts associated with the electricity and gas supply industries can be most efficiently controlled through emission rights or taxes. Regulation may be the more efficient option when dealing with projects which can have a significant impact on a local environment, extremely hazardous pollutants or where the metering of emissions is impossible, or very costly. However, attempts should be made to implement emission rights and tax schemes where environmental impacts are amenable to control through such measures.

These supply side approaches to reducing environmental damage are preferable to initiatives which concentrate on reducing demand through the mandatory conservation of energy. Through these supply mechanisms, the environmental effects of particular options will be included in the production costs of energy. This will encourage energy utilities to adopt more environmentally friendly supply techniques and, through higher prices, also encourage consumers to conserve more energy.

The applicability of the various approaches to solving environment problems, in particular in combating the potential for climate change, are being examined more fully in a current Commission inquiry into the emission of greenhouse gases.

The Commission believes that, if a particular emission is viewed as harmful, governments should consider either imposing a pollution tax, tradeable emission right, or performance standards in preference to a more rigid prescriptive standard. This would provide utilities with the flexibility to comply with emission controls in the most efficient (least cost) manner.

10.3.4 Information deficiencies

The incentive for households or businesses to utilise renewable energy technologies or to conserve energy are limited by a lack of information on the relative efficiency of the various options. In part, this is attributable to the cost to users of understanding, installing and adopting energy efficient technologies and practices. For instance, while commercial pressures stimulate users to make cost effective investments to reduce energy use, the cost involved in searching for these investments may sometimes outweigh the savings derived from improved energy use. This can occur when energy represents a small proportion of an enterprise's total costs or where the enterprise does not have any experience in energy use technologies. Similar difficulties are associated with the inability of property markets to capitalise fully the value of investments, in energy efficient buildings, into either resale values or rents.

To overcome some of these barriers, firms that specialise in providing energy advisory services have developed. Instead of charging clients directly for energy audits and retrofits, some energy consultants provide these services at no net cost to the client. The consultant's fees are specified as a proportion of 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.

Frequently, market pressures will also encourage the provision of some information on options to improve efficient energy use. For example, manufacturers of efficient appliances or insulation may provide such information as a marketing tool.

Although there are avenues, such as those mentioned above, for providing information about energy efficiency, most governments have perceived difficulties in this area and have taken steps to improve the availability of information. This has occurred in a variety of ways including the: distribution of information on energy options to raise a user's awareness of initiatives to save money and improve energy efficiency (eg distributing pamphlets); building of energy efficient display homes to demonstrate that energy savings are achievable; and the introduction of appliance energy labelling or building energy ratings schemes to help users make informed decisions when purchasing, or renting, an appliance or building.

However, a number of participants suggested that information programs will be insufficient to overcome the barriers to efficient energy use. For example, DASETT argued that:

> Information programs are, of course, important, but, on their own, they are the least effective technique for overcoming the barriers to economic investments in energy efficiency.

The role of fiscal incentives to further encourage the adoption of more energy efficient technologies was highlighted by the ACF:

> Low-interest loans, subsidies, cost transfer schemes, tax incentives and other financial incentives can be used by governments and/or utilities to encourage conservation initiatives.

Other participants also argued for the introduction of minimum efficiency standards for energy appliances and buildings. The rationale for these programs is that, if effective mechanisms cannot be established to provide energy efficiency information, governments should use their expertise to determine what constitutes an inefficient appliance or building practice, and then legislate to ensure the desired outcome is achieved.

However, it is costly both to governments and the community to provide energy use information, fund fiscal incentives and/or implement efficiency standards. Therefore, it is important to compare the potential benefits with estimated costs to decide whether a particular program is cost effective. Difficulties in obtaining reliable information on the relevant costs and benefits complicate this exercise. When assessing the impact of, say, minimum performance standards, it is relatively simple to estimate administrative costs and the cost of purchasing a more efficient appliance or building, and the related energy savings. However, it is more difficult to assess other benefits, such as increased comfort levels, and any associated indirect costs, such as installation, the residual value of discarded equipment, compliance costs and, perhaps most importantly, the costs that result from mandatory reductions in consumer choice.

For example, the energy efficiency of buildings can be improved through the addition of more insulation in either the ceiling or walls. However, installing insulation can involve considerable costs, particularly in the case of flat roofed buildings. Also, a consumer may prefer a heating appliance for an infrequently used room, a bathroom for example, 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 low capital cost, although running costs may be high. Similarly, less efficient heaters may be preferred in other circumstances where they are infrequently used, such as temperate climates (eg Sydney and the New South Wales north coast), when a heater is only required on a small number of days a year. In these, and many other, circumstances, minimum energy standards could impose additional costs on consumers if the preferred, though more ‘inefficient’, appliance is removed from the market.

In addition, fiscal incentives, to improve energy efficiency, create distortions if they are funded by non-participants. In particular, 'give away' programs and rebates offered by utilities, funded through general increases in energy tariffs, require non-participants (such as those with already low energy consumption) to cross-subsidise the energy consumption of the recipients.

Many of these type of costs, which are not normally borne by governments, appear to have been ignored in assessing the potential of options to improve efficient energy use.

The Commission recognises that governments are often required to make decisions in circumstances where they are less than fully informed. However, in the absence of estimates of the indirect costs associated with a particular program, any evaluation will be biased towards requirements which are too stringent.

Governments can avoid these indirect costs by concentrating on establishing mechanisms to combat inefficient use due to information deficiencies. One way for governments to do this is to provide the information (eg pamphlets on energy efficiency or energy efficient display homes) and allow users to choose rather than mandating particular actions. The effectiveness of information provision programs can be improved by targeting specific consumer classes and customising the information provided. For example, in Switzerland the electric utility BKAG established a power savers club in which members receive information and individual advice on how to conserve energy. This approach focussed on customers who had a commitment to conserve energy by requiring members to agree to use energy efficiently and to undertake self-audits of the savings achieved.

Another way governments have encouraged users to make informed purchasing or rental decisions has been to facilitate the establishment of energy appliance and building energy rating schemes. In Australia, energy appliance labelling has contributed to increases in the energy efficiency of appliances covered by the scheme. In the United States, residential rating schemes have led to more efficient building practices, increased the use of energy audits and resulted in lending institutions providing more favourable terms for energy efficient buildings and retrofit costs.

To avoid the distortions created by fiscal incentives and rebates, the beneficiaries of the incentive should, as far as is possible, pay for the cost of its implementation. Instead of a government giving away, or subsidising the sale of, energy efficient appliances, a utility or any other organisation could lease appliances to its customers. For example, in the United States, the Taunton Municipal Lighting Plant expects to earn a 15 to 25 per cent return on a program to lease energy efficient light bulbs to its residential customers.

Leasing offers an opportunity to overcome some of the barriers to improving efficient energy use: in particular, in those areas where investments in energy efficiency are assessed using higher discount rates than would be used by a utility when assessing an investment in additional supply-side investments. This occurs because leases do not require consumers to make an initial investment and because the benefits from a leased appliance (ie reduced energy bills) can be matched over time with its costs (ie lease repayments).

It has been argued that minimum standards can improve the efficient use of energy by eliminating the most inefficient appliances and activities (ie those options only an uninformed user would choose). In practice, however, this will be virtually impossible to achieve since it will be difficult for a regulator to conceive and allow for all possibilities including individual consumer needs and changing market circumstances. It is inevitable that some options, which would be effectively banned from the market by the imposition of efficiency standards, may be preferable for some consumers in some circumstances.

One approach, which would reduce any indirect costs, is to base standards on performance requirements rather than physical characteristics. For example, if regulation is justified, it could stipulate requirements for the thermal integrity of a building's shell, rather than specifying that insulation must be used. This would allow building owners the flexibility to comply with the standard in the most cost effective manner (eg it may be more efficient to reduce window space than install insulation).

Another approach is to introduce optional requirements. With optional requirements, manufacturers and builders can have their products or constructions certified that they conform to certain energy efficient standards. This is the approach which underlies both the current 5 Star Design Rating Scheme for buildings that operates in some states and the Australian Standards developed for a range of products by the Standards Association of Australia. Under this approach, decisions on energy efficiency would be left to users.

The Commission considers that prior to the implementation of programs intended to rectify problems caused by a lack of information, such as energy labelling 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. Where estimates of indirect effects are uncertain, such as with efficiency standards, the activity should be based on optional requirements.

The development of on-going assessment procedures are also required. In the development stages of a program this could consist of pilot studies to generate detailed cost and benefit information prior to the activity's final implementation.

The assessment criteria should be based closely on a benefit-cost framework and relate to the program's objectives. Where options are mutually exclusive (eg optional versus compulsory standards) or interrelated (eg the benefits of an information campaign being dependent on pricing structures), the assessment procedures should attempt to identify that strategy which maximises benefits.

The assessment criteria should also be used on an on-going basis to monitor the performance of the various activities.

10.4 Summary of proposals

A clear distinction needs to be drawn between those load management and energy conservation initiatives which are funded by energy utilities and those which are funded or undertaken by some other government agency.

Consistent with the Commission's rationale for corporatisation and treatment of CSOs, energy utilities should not be required to undertake DSM activities which are not in their commercial interest. This would preclude DSM activities which do not enhance utility revenues or reduce revenues to a larger extent than they reduce supply costs. If governments insist that utilities perform such activities, they should be separately identified and fully funded by government.

The appropriate role for government is to identify any institutional impediments or significant market failure which limit the efficient use of energy and, if cost effective, implement measures to address these problems. This requires that governments recognise the present policy contradictions: in particular, that government involvement in the operations of public utilities has distorted energy prices which, in turn, has impacted adversely on the incentives for the use of renewable energy and energy conservation.

The Commission's assessment of the appropriateness of load management and energy conservation initiatives has been limited by a lack of information on the benefits and costs of the various initiatives. A clearer picture should emerge once governments remove the institutional impediments to efficient supply and use of energy and include, as far as is possible, any environment costs in the supply decisions of energy utilities.

Load management initiatives have been adopted by utilities to even out the peaks and troughs in the demand for electricity and gas and to reduce the need for reserve capacity. The objective of time-of-use pricing and interruptible supply contracts should be for energy prices to reflect, as closely as possible, supply costs. Based on these prices, consumers should choose that pattern of energy use which is most suited to their lifestyle or business activities. Currently some load management initiatives are deficient because the options are limited to only a few end users or end uses, or because they do not fully reflect the costs of supply.

A number of energy conservation initiatives attack symptoms of problems associated with the existence of institutional impediments to the efficient use of energy and the non-inclusion of some environmental costs; for instance, inducements for the use of energy efficient appliances (eg rebates subsidised by other energy users) or encouragement of energy conservation to reduce potential environmental impacts. These address the symptoms rather than the cause of the problem. More appropriate would be programs targeted at overcoming the cause of the problem (eg lack of information and inappropriate pricing).

In addressing the potential environmental impact associated with energy supply, governments should consider either imposing a pollution tax, tradeable emission right or performance standards in preference to a more rigid prescriptive standard. This would provide utilities with the flexibility to comply with emission controls in the most efficient (least cost) manner.

The Commission is less clear on the appropriateness of a range of energy conservation initiatives such as the provision of energy efficiency information to consumers, labelling of appliances, energy rating of buildings or imposition of minimum energy efficiency standards. This uncertainty is largely attributable to the difficulty of taking into account the indirect costs of these initiatives.

Implementation of the Commission's proposals would not, as asserted by DASETT, mean the discontinuance of all utility initiated demand management programs and least cost energy planning strategies. While implementation of the Commission's proposals may result in some programs being undertaken by government rather than energy utilities, they would not necessarily lead to the discontinuance of any. The Commission clearly supports some initiatives (eg advisory services providing enhanced information to consumers) while pointing to the need for further study of others (eg mandatory standards as opposed to optional standards or labelling).

The Commission recommends that:

- governments remove requirements that oblige electricity and gas utilities to undertake non-commercial demand side management activities.

- governments focus on addressing institutional impediments (eg government policies which prevent energy prices from reflecting supply costs) and market failures (eg environmental concerns and information gaps) which impede the efficient use of energy, provided it can be demonstrated that net benefits would result.

- subject to appropriate environmental and other safeguards, the question of nuclear electricity generation in Australia be determined by commercial considerations.

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