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9.1 Introduction

For most of the postwar period, major parts of the energy sector of the U.K. economy have been dominated by publicly owned enterprises. The bulk of economic activity in the electricity, gas, and coal industries has been placed in the hands of public corporations which have, to varying degrees, been protected from competition by statutory monopoly rights. Only in oil, where public ownership has been more limited, has the private sector been allocated the major role, and, even here, public policy has had a pervasive effect on the evolution of the industry.

Even before the advent of the privatization program, however, the structure of the energy industries was far from static. In the late 1940s and early 1950s primary fuel supplies were largely drawn from the coal industry. As well as being the principal source of energy for domestic space heating and for many of the country's major industries, coal was the basic input for both the generation of electricity and the production of gas. During the 1950s and 1960s this picture changed somewhat as relatively cheap imported oil became more readily available (see table 9.1). Petroleum products gradually increased their share of inland consumption of primary

Table 9.1 Inland consumption of primary fuels: total consumption (millions of tonnes of coal equivalent) and market shares, 1950-1985

Year	Total inland consumption	Market shares (percent)				
		Coal	Petroleum	Natural gas	Nuclear electricity	Hydro-electricity
1950	228.1	89.6	10.0	--	--	0.4
1955	253.9	85.4	14.2	--	--	0.4
1960	269.4	73.7	25.3	--	0.4	0.6
1965	303.3	61.8	35.0	0.5	2.0	0.7
1970	336.7	46.6	44.6	5.3	2.8	0.7
1975	324.8	36.9	42.0	17.1	3.4	0.6
1980	328.7	36.7	37.0	21.6	4.1	0.6
1985	326.9	32.2	35.2	25.2	6.8	0.6

Source: *Digest of U.K. Energy Statistics* (1986).

fuels until the early 1970s, by which time they had overtaken coal as the U.K.'s principal source of energy. The oil price shock of 1973 reversed this trend, however, and since that date the market share of oil has fallen significantly.

Apart from the substitution of oil for coal, another major change in energy markets resulted from the discovery and exploitation of substantial offshore reserves of gas and oil in the U.K. Continental Shelf (UKCS). This explains the steady expansion in the use of natural gas as a primary fuel input from the mid-1960s onwards and gave rise to a substantial restructuring of the gas industry which we will describe later. Not shown in the table is the later shift from imported to domestically produced oil which took place during the 1970s and early 1980s, and which in turn led to the emergence of new set energy policy issues.

These changing patterns in sources of energy have had major effects on the respective roles played by public and private producers over the last 40 years. Thus, prior to the development of UKCS reserves, public corporations were responsible for both the production and distribution of gas. However, since the bulk of offshore production of gas (and oil) has been undertaken by private producers, the public sector in the industry has, in the more recent periods, focused its attention chiefly on gas distribution and sales. Similarly, prior to privatization, the growth in the importance of petroleum products implied some overall diminution in the scope of the public sector's role in the *production* of primary fuels (although in electricity and coal public corporations have retained their production monopolies throughout the postwar period).

It is against this background that we will evaluate the U.K. Government's privatization program for the energy industries. We start, in section 9.2, with the gas industry, which was transferred to the private sector in 1986. The approach adopted by the Government in this case bears many resemblances to that followed in the telecommunications industry, and several of the points that we make echo arguments developed in chapter 8. Section 9.3 then considers the prospects for the privatization of the electricity supply industry. The ordering here is governed by the similarity of the economic issues surrounding electricity privatization to those surrounding the gas and telecommunications asset sales: in each case we are confronted by a network industry with significant elements of natural monopoly in parts of its operations. Thus, although the sale of state oil assets preceded Government plans for the privatization of electricity, and although the offshore oil and gas industries are closely linked, evaluation of the oil privatizations is deferred until section 9.4. This

discussion is followed, in section 9.5, by an examination of some of the questions facing policy makers with respect to the future of the British coal industry, including questions about the likely consequences of partial or complete privatization. Finally, in section 9.6, we summarize our principal conclusions concerning competition, regulation, and privatization in the energy industries.

9.2 The British Gas Industry

In December 1986, British Gas became the second public utility company to be transferred to the private sector. Unlike in the British Telecom (BT) case, the Government did not retain a sizeable shareholding in the new company, but for the most part the two utility privatizations are marked by their similarities rather than their differences. Thus, for example, the sale of British Gas was accompanied by the creation of a new regulatory body, the Office of Gas Supply (Ofgas), and price controls have been established in markets where competition from other fuels is weak.

The organization of the material in this section is therefore similar to that in chapter 8. We begin with a short history of the gas industry in Britain (section 9.2.1) and an analysis of the industry's structure (section 9.2.2). These are followed, in section 9.2.3, by a discussion of the framework of competition and regulation that has evolved over the recent past, with particular emphasis being given to the Oil and Gas (Enterprise) Act 1982 and the Gas Act 1986—which were concerned with liberalization and privatization respectively—and to the Authorisation granted to the newly privatized British Gas by the Secretary of State for Energy. The final part of the analysis (section 9.2.4) comprises an assessment of the policies implemented by the Government in the course of the privatization exercise together with a few brief remarks on three of the main events in the nine months following the flotation of British Gas: the company's first conflict with Ofgas, its first major acquisition, and an attempt by large industrial customers of the company to elect Sir Ian MacGregor to the Board of Directors.

9.2.1 The History of the Industry

The first public supply of gas in Britain was made under a Royal Charter granted in 1812 to the Gas Light and Coke Company for street lighting in London. By 1850 the number of gas suppliers had grown to nearly 700, with the main application continuing to be street lighting. Thereafter the use of

gas in the home and in industry increased steadily until, by the mid-1930s, there were approximately 11 million gas customers.

The industry was nationalized in 1948. Prior to that gas supply was divided between municipal undertakings and commercial companies. The municipalities accounted for approximately 37 percent of the industry, and virtually all the remaining supply was in the hands of 509 commercial utility companies. The latter were subject to stringent statutory provisions designed to restrict profits and hold down prices, and a variety of schemes were in force to link prices to profits in ways intended to strike a balance between the interests of consumers and stockholders. In all there was a total of 1,046 gas companies and undertakings in existence at the time of nationalization.

The Gas Act 1948 led to the amalgamation of these companies and undertakings into twelve Area Boards, each of which was largely autonomous as regards the manufacture and supply of gas. In addition the Act created a central body, the Gas Council, which was allocated a supporting role in the industry. The statutory duties of the Council included the provision of advice to the Minister, organizing research programs, education and training, the manufacture and supply of gas fittings, and raising finance for individual Area Boards on the credit of the whole industry.

According to the Report of the Committee on the Gas Industry in 1945 (the Heyworth Report), the perceived advantages of nationalization mostly related to the attainment of various types of scale economies. Nevertheless, the Heyworth Committee concluded that there were no major *national* problems facing the industry, and that organization on a national scale to manufacture and distribute gas was therefore unnecessary for the achievement of the available economies. In particular, the Committee argued that a national grid was not practicable, that it was not economic to supply gas to every part of the country, and that selling prices could not usefully be fixed on a national basis. Given these arguments, the Labour Government opted for a regionally decentralized form of public ownership.

The reasoning of the Heyworth Committee, however, was subject to almost immediate challenge. As early as 1953 the Gas Council reported that the benefits of planning and control of production and distribution over far larger areas than was previously thought necessary were leading to more centralized forms of organization. Subsequently, changes in technology, including the introduction of natural gas, gave a further impetus to the trend towards centralization.

Until the 1950s gas was derived mainly from coal, but sharp increases in

costs in the post-nationalization period led to a search for alternative methods of production. The first major technological advance, achieved in the late 1950s and early 1960s, was the production of high pressure gas through the gasification of oil. Next, in 1964, came the introduction on a commercial scale of imported natural gas, which was distributed through a high pressure pipeline from the Thames estuary to eight of the twelve Area Boards. Finally, substantial quantities of natural gas were discovered in the North Sea Basin in the mid-1960s, and these reserves provided the basis for the development of domestic production of natural gas.

When natural gas was first imported into Britain it was processed to make it suitable for use in existing appliances. However, the discovery of abundant reserves in the North Sea made it economic to embark upon a national program of converting all appliances to use natural gas. The program started in 1967, following the first landing of natural gas from the North Sea, and was completed a little over ten years later, by which time approximately 35 million appliances, operated by about 13 million customers, had been modified. In addition, the new circumstances led to the construction of a national high pressure gas transmission system to take North Sea gas from beachheads to the off-take points of the regional distribution systems.

As a result of these technological developments the industry was centralized in 1972. Under the Gas Act 1972 the Gas Council was renamed the British Gas Corporation (BGC) and it took over the operations of the 12 separate Area Boards. In addition, the Act gave the BGC increased power to search for and obtain supplies of gas and oil, although subsequently, in 1983 and 1984, it was required to dispose of the majority of its oil interests as part of the privatization program (see section 9.4). Until 1982 the BGC was also granted monopsony powers in respect of the purchase of North Sea Gas. However, that year saw the introduction of the Oil and Gas (Enterprise) Act, aimed at liberalizing the market by establishing common carriage provisions which, in principle, allowed other suppliers to transmit their gas through the BGC's pipeline network (see section 9.2.3).

In May 1985 the Government announced its intention to privatize the gas industry, and the necessary legislation (the Gas Act 1986) received the Royal Assent in July 1986. This provided for the complete business of the BGC to be transferred to a new company, named British Gas plc, and for the establishment of a framework of regulation for the industry. All the ordinary shares of British Gas were sold in December 1986 at a market capitalization of £5,602.5 million. Partly to reduce the magnitude of the share issue, however, the company was required to issue an unsecured

£2,500 million debenture to the Government, which was repayable in tranches in each of six successive years starting in 1987. In effect, therefore, the Exchequer will continue to receive proceeds from the sale until 1991.

9.2.2 The Structure of the Gas Industry

The major activities of the British gas industry are as follows:

- (i) the production of natural gas, mostly from offshore fields;
- (ii) transmission of gas to beachhead landing points;
- (iii) transmission of gas from the beachhead to regional off-take points;
- (iv) local distribution of gas to customers' premises;
- (v) the sale of gas;
- (vi) the sale, installation, and servicing of gas appliances.

Before considering these activities in more detail, it is worth noting that the nationalized BGC enjoyed monopoly positions in respect of activities (iii)–(v), and a monopsony position in respect of purchases of gas supplies. We will argue later that privatization has not materially altered this situation, and that British Gas will therefore continue to operate as a monopolist-cum-monopsonist for the foreseeable future.

Gas Supplies Exploration for and extraction of natural gas, together with transmission to the beachhead, is mostly carried out by oil companies operating on the UKCS. However, British Gas has itself been involved in these activities since the mid-1950s, and by the early 1980s it had built up quite sizeable interests. As a result of the privatization program, these interests were reduced by the enforced sale of the BGC's 50 percent stake in the license for the small (onshore) Wytch Farm oil field in 1984, and of its stakes in five offshore oil fields and a further 20 offshore exploration blocks (which formed the initial assets of Enterprise Oil in 1983). Nevertheless, British Gas continues to have the largest single share of proven and provable gas reserves in the UKCS, amounting to about 15 percent of the total. Approximately 80 percent of the company's reserves lie in one offshore field, the South Morecambe gas field.

In the year ended 31 March 1986, British Gas obtained about 5 percent of its gas supplies from its own fields. However, with the exception of small volumes used in the manufacture of chemical feedstocks, *all* current UKCS production is either purchased or owned by British Gas. These sources account for about 75 percent of the company's supplies, the remainder being derived from the Norwegian sector of the North Sea.

One important feature of the market for gas supplies is the wide variation in the prices paid for gas from different fields. Most British Gas purchase contracts provide for an initial term of approximately 25 years, and the price payable for the gas is generally determined for the entire length of the contract via the specification of an initial base price and an explicit price variation formula. The latter provides for year-to-year changes in the price that are linked to variations in observable price indices for other commodities. Before 1980 most contracts linked these adjustments to changes in the U.K. Producer Price Index, but more recently the variation provisions have tended to make reference to the prices of competing fuels including heavy fuel oil, gas oil, and electricity.

The pricing provisions (and particularly the level of the base price) of gas purchase contracts reflect market conditions at the time they are concluded and, since fields come on stream at different dates, this partly accounts for the wide dispersion in the prices currently payable. For example, as exploration has proceeded additional supplies have increasingly been drawn from less accessible discoveries that have been more expensive to exploit. In principle, it would have been possible to link contract prices to changes in marginal production costs, but, in practice, such provisions would have had unfavorable incentive properties: offshore producers would then have benefited from the inefficient exploitation of later discoveries. A second important reason for the observed price dispersion is that gas purchased under contracts entered into before 1 July 1975 is exempt from U.K. petroleum revenue tax (see section 9.4).

Thus the first UKCS fields (the Early Southern Basin Fields) were relatively cheap to develop, and the contract terms were settled before both the first oil price shock in 1973 and the introduction of petroleum revenue tax. As a consequence, under the provisions of the long-term contracts, British Gas has been able to obtain supplies from these fields at prices well below levels that those supplies could have subsequently commanded if offered for sale on a spot market, and substantially below the levels applicable to contracts concluded during later periods.

Hence, although the average price paid by British Gas for supplies in the year to end-March 1986 was 17.2 pence per therm, prices for Early Southern Basin gas were much lower than this while prices for gas from fields developed in later periods were much higher. The anomaly arising from the differential application of petroleum revenue tax was partially corrected by the Gas Levy Act 1981, which introduced a tax (currently standing at 4 pence per therm) on gas purchased under contracts signed before July 1975. In 1985–1986 the levy was applicable to about 65 percent

of gas purchases, and had the effect of raising the average cost of British Gas's supplies from 17.2 pence per therm to 19.9 pence per therm. Nevertheless, even allowing for the levy, the average cost of supplies continues to be well below the purchase prices settled in recent contracts. Gas from the Norwegian Frigg field, for example, is estimated to have commanded landed prices in excess of 30 pence per therm in the mid-1980s.

The proportion of gas taken from the Early Southern Basin Fields has declined over recent years and will continue to fall in the future. In the financial year 1981–1982 these fields accounted for 61 percent of supplies, but by 1985–1986 the figure was down to 44 percent and it is expected to decline to around 30 percent by 1991–1992. Upward pressure on average purchase prices from these shifts can therefore confidently be anticipated.

Transmission and Distribution Natural gas enters the national transmission system at five coastal terminals. After treatment and measurement the gas is then carried at high pressure to over 100 regional off-take points, where it passes into the regional transmission system which conveys it to the main centers of demand. Finally it enters the local distribution systems, where pressure is gradually reduced until the gas reaches the meters of the 16 to 17 million customers.

The pipeline mileages in 1986–1987 were as follows: national transmission, 3,300 miles; regional transmission, 7,650 miles; local distribution, 135,000 miles. All this supply network is owned and operated by British Gas, and inspection, maintenance, and renewal of the network constitute a significant part of the total activities of the company.

Given the need to maintain pressures in the integrated pipeline network, preserving the balance between supply and demand at each point in the system is a vitally important function. The task is performed by two central control rooms (one concerned with overall supply strategy, including the management of off-takes from the various fields, and the other with day-to-day balancing of supply and demand throughout the transmission system) and 12 regional centers, each connected to the day-to-day control room and responsible for meeting demand within its own region.

Seasonal variations in demand for gas are quite marked—up to five times higher on a very cold winter's day than on the warmest summer day—and these are handled in one of five ways:

- (i) varying the amount of gas taken from the supplying fields;
- (ii) provision of seasonal supplies from fields specially developed for this purpose (e.g. South Morecambe);

- (iii) making use of the Rough storage facility, a small field lying about 20 miles offshore, into which gas can be compressed during periods of low demand and from which gas can be withdrawn during seasonal peaks;
- (iv) taking gas from liquefied natural gas storage installations and from underground storage cavities;
- (v) interrupting supplies to certain large industrial and commercial customers who are willing to allow British Gas this option in exchange for lower unit prices.

Gas demand is also subject to wide variations during the course of the day—maximum demand may be up to four times the minimum level—and these are mostly catered for by approximately 1000 local storage units.

Gas Sales British Gas supplies over 99 percent of the natural gas used in the U.K. Between 1975 and 1985 the total number of therms supplied by the company to the U.K. energy market (excluding transport) increased by about 50 percent, despite an overall fall in domestic energy consumption over this period of approximately 6 percent. Accordingly, the market share of gas rose from 28 to 42 percent. The market can be broken down into three broad sectors: domestic, industrial, and commercial. Their relative sizes in 1985–1986 are shown in table 9.2.

The principal domestic uses of gas are for home heating, water heating, and cooking, with central heating accounting for over 50 percent of domestic sales. The main competing fuels are solid fuel, oil, and electricity for heating purposes, and electricity for cooking. In the short term, and particularly with respect to central heating, competition amongst the various fuels is limited by (sunk) consumer investments in associated equipment.

Nevertheless, competition does take place over longer time periods, and between 1975 and 1985 gas increased its share of the domestic market from 40 to 58 percent, with the number of therms sold rising by more than 60 percent against a total market growth of around 13 percent. The most

Table 9.2 Breakdown of British Gas's sales, 1985–1986

Market	Therms sold (percent)	Sales value (percent)	Customers (percent)
Domestic	53.7	61.2	96.5
Industrial	31.6	24.6	0.5
Commercial	14.7	14.2	3.0

Source: *British Gas Prospectus* (1986).

important single factor in this change was the increasing use of gas for central heating: between 1980–1981 and 1985–1986 76 percent of the central heating systems installed in the U.K. were gas fired.

The industrial market for gas is conventionally split into two main categories: premium and nonpremium. The first comprises customers requiring a fuel that is clean and readily controllable, and does not have to be stored. In the premium market gas competes against gas oil and, to a lesser extent, against liquefied petroleum gas and electricity. The nonpremium market consists of customers whose principal requirement is crude bulk heat. Here gas competes against heavy fuel oil and coal, and, unlike in the premium market, purchase contracts usually allow British Gas to interrupt supplies at times of high system demand. In addition to these two main categories, gas is also supplied to the industrial market for use as a chemical feedstock in the manufacture of fertilizers, largely on an interruptible basis.

Demand growth in the industrial market has been much slower than in the domestic market. Between 1975 and 1985 the total number of therms sold rose by around 17 percent, although there was a slight decline between 1979 and 1985. However, the market share of gas increased steadily throughout the ten-year period, rising from 23 percent in 1975 to 36 percent in 1985.

One characteristic of the industrial market is the large volume of gas supplied per customer. In the accounting year 1985–1986, the three largest customers together accounted for 10 percent of the total number of therms sold by British Gas in *all* markets, and the largest customer (Imperial Chemical Industries) alone accounted for 7 percent of total sales. About 55 percent of the industrial market, representing about 12 percent of the total revenue of British Gas, is supplied on an interruptible basis. Since customers with interruptible contracts can be assumed to have the capacity to switch readily and quickly to alternative fuels, conditions conducive to effective competition amongst fuels exist in this area. It is also worth noting that, in the main, gas is supplied to customers under contracts that are individually negotiated.

The commercial market for gas largely comprises customers in the service industries and the public sector, including education (the largest single component, accounting for about 20 percent of commercial sales), shops, offices, public buildings, hotels, and restaurants. Over two-thirds of the gas consumed in the commercial sector is used for space heating, with water heating and catering being the next most important uses. For heating

purposes gas competes chiefly with oil and electricity, while in catering electricity is the principal competing fuel.

About 50 percent of gas supplies to the commercial market are provided under individually negotiated contracts. The remainder, mostly to smaller-volume customers, is supplied according to published tariffs which consist of a standing charge and a rate per therm. Over the past ten years demand for energy in the commercial sector has been more buoyant than in the industrial market. The number of therms sold nearly doubled between 1975 and 1985, and, as in the domestic and industrial markets, the market share of gas rose steadily, from 19 percent in 1975 to 34 percent in 1985.

Appliance Sales, Installation, and Servicing British Gas sells appliances from approximately 800 showrooms distributed throughout the country, which also serve as points where domestic gas bills can be paid. In 1985–1986 sales volumes were approximately as follows: central heating systems, 100,000; space heaters, 700,000; cookers, 500,000; other appliances, 100,000. Appliance sales have also been supported by installation and servicing activities. During 1985–1986 approximately 3.5 million appliances were covered by British Gas service contracts, and between 1981–1982 and 1985–1986 inclusive the company installed about 100,000 central heating systems and 1.6 million other appliances.

In its appliance sales and installation and servicing activities British Gas competes with privately owned retailers and a large number of independent service engineers. It does, however, derive a major competitive advantage from the existence of the large staff of engineers required for the provision of “essential” services that are part of its gas supply business, including dealing with gas escapes and other emergencies, installation and repair of meters, and safety checks on appliances. Since this latter type of work is highly seasonal, British Gas is able to offer “off-peak” labor at favorable rates for the installation and servicing of appliances in periods other than the winter months.

Financial Results Table 9.3 sets out the current cost accounting (CCA) and historic cost accounting (HCA) profit and loss accounts for British Gas for the years ended 31 March 1986 and 31 March 1987, and table 9.4 provides a breakdown of the company’s fixed tangible assets at the end of each of those years. In terms of revenues received, it can be seen that gas supply (transmission, distribution, and sales) is the predominant part of the business, and that, likewise, pipelines and related equipment dominate the company’s asset structure. In terms of profits, the relative contribution of

gas supply is even higher. The CCA operating profit of £688 million in 1985–1986, for example, can be broken down as follows: gas supply, £703 million; installation and contracting, £11 million; appliance trading, £12 million; exploration subsidiaries, –£43 million; other activities, £5 million. The principal component of the cost of sales was expenditure on gas purchases (including the gas levy) which totalled £3,896 million in 1985–1986, while operating costs include salaries, wages, and related costs (£1,202 million in 1985–1986) and depreciation (£431 million on a CCA basis in 1985–1986).

The increase in operating profit between the two years is largely attributable to a fall in gas purchase costs of approximately 9.5 percent, which in turn was a consequence of the impact of falling oil prices on the escalation provisions of gas purchase contracts. As a result, the company's rate of return—defined here as the percentage ratio of operating profit to average capital employed—rose from 4.1 to 5.8 percent on a CCA basis, and from 15.3 to 18.5 percent on an HCA basis.

9.2.3 The Framework of Competition and Regulation

Although the gas industry was highly fragmented prior to nationalization

Table 9.3 British Gas: profit and loss accounts, 1985–1986 and 1986–1987

	CCA (£ million)		HCA (£ million)	
	1986	1987	1986	1987
Turnover				
Gas supply	7,109	6,967	7,109	6,967
Installation and contracting	275	310	275	310
Appliance trading	278	300	278	300
Exploration subsidiaries	94	189	94	189
Other activities	21	28	21	28
Intragroup sales	–90	–184	–90	–184
Total turnover	7,687	7,610	7,687	7,610
Cost of sales	4,598	4,135	4,539	4,150
Gross profit	3,089	3,475	3,148	3,460
Operating costs	2,401	2,470	2,142	2,216
Operating profit	688	1,005	1,006	1,244
Net interest receivable	94	49	94	49
Gearing adjustment	0	8	0	0
Profit before taxation	782	1,062	1,100	1,293
Taxation	380	487	380	487
Profit for the year	402	575	720	806

Source: *British Gas Annual Report and Accounts* (1987).

Table 9.4 The tangible fixed assets of British Gas

	CCA (£ million)		HCA (£ million)	
	1986	1987	1986	1987
Land and buildings	1,190	1,279	363	390
Pipelines etc.	13,778	13,958	4,111	4,198
Gas and oil fields	1,609	1,518	1,420	1,431
Other	188	220	156	183
	16,765	16,975	6,050	6,202

Source: *British Gas Prospectus* (1986), *British Gas Annual Report and Accounts* (1987).

and contained large numbers of both municipal and private enterprises, competition in markets for gas sales was relatively limited: firms tended to operate in separate areas and to supply distinct groups of customers. Private companies were therefore subject to a variety of types of price and profit regulation.

Nationalization substantially reduced the number of firms in the industry, initially to the twelve Area Boards and later to a single public corporation. In the ensuing period product market competition remained notable by its absence, while regulatory policy evolved along the lines set out in chapter 5. By the 1970s the policy framework for the industry had been brought into line with that pertaining in telecommunications and electricity generation: there was a single national firm, protected from competition by statutory entry barriers and regulated by a department of central government. The underlying rationale for this approach was the familiar argument that the core activities of gas transmission and distribution constituted a natural monopoly, and that the operation of more than one firm in the market would therefore lead to cost inefficiencies. To protect consumers from the effects of the resulting market power, it was considered desirable that the industry should be publicly owned and controlled.

It is true, of course, that the BGC faced competition from other fuels in the wider market for energy, particularly in the longer term. Even here, however, competition was attenuated by the fact that two of the principal competing fuels, electricity and coal, were supplied by publicly owned industries whose pricing policies and competitive activities were themselves controlled by the Government. Moreover, Governments were also able to exercise control over the market prices of the various oil products by means of commodity taxes, and did in practice use these tax instruments to reduce the competitive pressures on the other energy industries, particularly coal (see section 9.5).

A slightly more surprising feature of the policy regime during the period of nationalization was the statutory monopsony position with respect to the purchase of gas that was granted to the BGC. Before reorganization of the industry in 1972 it would have been possible to have arranged for the Area Gas Boards to compete amongst themselves for gas supplies from the offshore producers. However, even during these early stages of the development of UKCS natural gas, it was the Gas Council that, on behalf of the Area Boards, entered into contracts with the firms involved in gas exploration and extraction. The 1972 reorganization therefore had little direct impact on competition in the market for gas purchases, although it did impede the possible later development of such competition as a deliberate policy measure.

One justification for the statutory monopsony in the purchase of gas was a desire to prevent appropriation of the rents associated with gas production by the offshore operators. This motive also helps to explain the attitude of British Governments to international trade in gas: both imports and exports have been strictly controlled and, while substantial imports have been allowed (most notably from the Norwegian Frigg field), exports by UKCS producers were effectively prohibited prior to privatization. As a result the market power of British Gas vis-à-vis UKCS producers was greatly strengthened, helping to maintain downward pressure on the prices producers could obtain for their supplies. However, the income-distribution problems connected with the accrual of rents on an exhaustible natural resource could easily have been solved by establishing appropriate taxes on producers, the solution that was later adopted for UKCS oil production when petroleum revenue tax was introduced. The award of a statutory monopsony position to the BGC appears to have been an extremely clumsy piece of economic policy.

The consequences of the gas monopsony might not have been overly detrimental if, in setting prices in the domestic, industrial, and commercial markets, British Gas had adopted a long-run marginal cost pricing policy, in accordance with the provisions of the 1967 White Paper on nationalized industries. In that event final selling prices would have reflected the marginal opportunity cost (the "efficient" price) of gas supplies, and customers would have been faced with accurate signals as to the value of gas they were consuming. In practice, however, the BGC based selling prices on the *average contract* price of its supplies. Because of the existence of the Early Southern Basin contracts, the effects of the oil price shocks on gas markets, and the escalating costs of extraction from less accessible

fields, this average contract price has typically been well below best estimates of marginal opportunity costs between 1973 and 1987 (although falling world energy prices towards the end of the period may have narrowed the gap). Thus, in the early 1980s for example, a report by the consultants Deloitte, Haskins, and Sells (1983) concluded that the BGC was selling at less than the marginal cost of supply in all markets except the interruptible industrial market. Price (1984) estimated that prices to domestic and "firm" (i.e. noninterruptible) industrial customers were 12–17 percent below long-run marginal costs, and Newbery (1985) estimated that, although industrial prices appeared to be about right, domestic customers were paying up to around 20 percent too little at the margin.

It is likely, therefore, that much of the gain in the market share of gas between 1975 and 1985 was attributable to suboptimal pricing policies (a view that will receive support when we come to discuss electricity and coal pricing in later sections). That is, the changing market shares of the various fuels in this period may owe less to changes in their respective opportunity costs than to the failure of regulatory policy to establish and enforce appropriate pricing policies in energy markets.

Liberalization: the Oil and Gas (Enterprise) Act 1982 The statutory monopsony with respect to the purchase of gas from UKCS producers was nominally ended in 1982 by the Oil and Gas (Enterprise) Act which, along with the British Telecommunications Act 1981 and the Energy Act 1983, reflected a shift in public policy toward an increased emphasis on the use of competitive forces as a method of influencing the performance of nationalized utilities.

The Act provided for the use of the BGC's pipeline network by competing suppliers or by any other persons wishing to transport gas. It stipulated that the consent of the Secretary of State for Energy was required for gas to be supplied through pipes to *any* premises or for the use of the British Gas pipelines. However, it stated that consent would automatically be denied for supply to persons within 25 yards of a gas main unless that supply amounted to not less than 25,000 therms per annum. A person providing gas for himself was excepted from these requirements, as were supplies greater than or equal to 2 million therms per annum.

The Act did not attempt to specify the terms on which the BGC was required to provide pipeline services to other persons (the vital issue of "interconnection" discussed in chapters 3 and 8); these were left to be

determined by negotiations between the BGC and the user. However, the user was afforded the right to make an application to the Secretary of State on this matter, and the Secretary of State was empowered to give directions to the BGC in respect of appropriate terms and conditions.

Thus, in theory, since 1982 UKCS producers have been free to negotiate direct sales of gas to larger consumers. In the event, however, no use has been made of the provisions of the Act to date, and the legislation has had no discernible effect on the degree of competition in the U.K. gas industry. The reasons for this apparent failure of policy are several and, taken together, they underline the point that, given the structure of the gas supply industry, much stronger liberalizing measures are required if significant competition is to be introduced into the market.

The obstacles facing a new entrant include the following.

- (i) The 1982 Act effectively excludes new suppliers from the domestic market, which constitutes both the largest and most profitable market segment.
- (ii) The lower-margin commercial and industrial markets are highly fragmented, tending to raise the penetration costs for a new supplier.
- (iii) The largest customers are supplied on a contract basis: terms and conditions of supply are individually negotiated and are not published. Hence, there are significant incentives for British Gas to engage in predatory pricing in the event that new suppliers attempt to enter the market (price cuts can be localized, thereby reducing the impact of aggressive policies on total revenue).
- (iv) With a large integrated supply system British Gas is able to offer superior security of supply than a potential rival. In obtaining gas from other sources the customer would typically need to make provision for back-up or top-up supplies from British Gas, and the latter has every incentive to impede entry by seeking to impose unduly onerous terms for this service.
- (v) The new entrant must negotiate terms with British Gas for the use of the pipeline network. This provides scope for the dominant firm to impede entry by charging an excessively high price for the transport facilities. Although the rival supplier could appeal to the Secretary of State—and, since privatization, can now appeal to the Director General of Gas Supply—the uncertainties and delays that are involved serve to raise entry costs. Moreover, the need to negotiate for pipeline use provides British Gas with an early signal of the entrant's intentions, giving the dominant firm time to offer better terms to the targeted customer.

(vi) Finally, as already explained, British Gas's average gas purchase costs have generally been below marginal opportunity costs. Since all earlier supplies of gas from the UKCS were sold to the BGC under long-term contracts, the most likely type of new entrant would be an operator of an undeveloped or newly developed field who had uncommitted gas to offer. The unit gas costs of such an operator would, however, typically be much greater than British Gas's average purchase cost and, given the pricing policies of the dominant firm, it would be difficult for an entrant, even if more efficient than British Gas, to offer more favorable terms to the customer.

It is also worth noting that the Oil and Gas (Enterprise) Act did little to erode British Gas's monopsony position with respect to the purchase of UKCS gas supplies. The Act did not amend the "landing requirement" whereby all gas produced on the UKCS is required to be brought onshore in the U.K. Given the economics of gas production and transportation, the landing requirement continued to prevent the emergence of an effective export option for the offshore producers, and therefore blocked development of the more competitive gas market that would have been feasible had UKCS fields been able to build direct pipeline links to the continent.

The Gas Act 1986 The framework of the privatized gas industry was established by the Gas Act 1986. The Act has many features in common with the preceding telecommunications legislation although, for reasons to be discussed below, the resulting policy regime is likely to be even less conducive to the development of effective competition than in the case of telecommunications. As a result of the latter feature, the legislation was subject to a good deal of hostile criticism in Parliament and by the press, academics, consumer bodies, and potential competitors, although the impact of these various groups on its final form was extremely limited.

The main statutory provisions of the Act are as follows.

Section 1 empowers the Secretary of State to appoint the Director General of Gas Supply (DGGS), who in turn may appoint the staff of an Office of Gas Supply (Ofgas).

Section 2 establishes the Gas Consumers' Council, a consumers' "watchdog" body.

Section 3 abolishes British Gas's monopoly privilege with respect to the supply of gas through pipes, opening the way to the possible authorization of alternative suppliers.

Section 4 sets out the guidelines to which the Secretary of State and the

DGGS must have regard in carrying out their functions. In the original Bill that was presented to Parliament these included meeting all reasonable demands for gas, the protection of consumer interests with respect to prices, continuity and quality of supply, the promotion of efficiency in gas supply, and the protection of the public from dangers arising from the distribution and use of gas. However, Parliament later amended the bill so as to include a duty on the Secretary of State and the DGGS to act in the way best calculated "to enable persons to compete effectively in the supply of gas through pipes at rates which, in relation to any premises, exceed 25,000 therms a year." As with guideline (b), section 3, of the Telecommunications Act 1984 this gives additional scope for pro-competitive decisions by a regulator so inclined to act, although, unlike in telecommunications, the duty is only imposed with respect to one section of the market.

Section 5 makes supplying gas without an authorization a criminal offence (although clause 6 then exempts supplies of over 2 million therms per annum from this prohibition).

Section 7 empowers the Secretary of State to authorize a "public gas supplier" to supply gas through pipes to any premises within a designated area. The clause also provides for the inclusion in authorizations of certain conditions (for example, the payment of fees, and provision of information to the DGGS or the Gas Consumers' Council). Most significantly, except in special circumstances, it prevents authorizations for areas situated within 25 yards of the mains of another public gas supplier. Thus, given the initial authorization of British Gas, section 7 blocks the emergence of a competing public gas supplier in most of the relevant market.

Section 8 empowers the Secretary of State or the DGGS to authorize any person or persons to supply gas to specified premises when either the premises are not within 25 yards of a public gas supplier's distribution main or the supply involved is expected to exceed 25,000 therms per annum. Hence, section 8 has the effect of allowing the development of competition in supplies to large commercial and industrial customers.

Section 9 imposes general duties on a public gas supplier, including a duty to "avoid any undue preference in the supply of gas to persons entitled to a supply . . ." It remains to be seen how exactly this clause will be interpreted but, in general, it appears designed to prevent excessive price discrimination.

Section 10 imposes a duty on a public gas supplier, when the customer so requests, to give and continue to give a supply of gas of up to 25,000 therms per annum to any premises that are either within 25 yards of a distribution

main or are already connected to such a main. However, since customers requesting in excess of 25,000 therms per annum are not "entitled to a supply," this has the effect of limiting the applicability of section 9; there is therefore no statutory duty on a public gas supplier to avoid undue preference in its dealings with large industrial and commercial customers.

Section 14 requires a public gas supplier to charge in accordance with fixed tariffs any consumer using no more than 25,000 therms per annum (labelled a "tariff customer"), and stipulates that a public gas supplier "shall not show undue preference" in fixing tariffs.

Section 19 empowers the DGGS, on application of another person, to give a public gas supplier directions securing to the applicant the right to use a pipeline owned by the public gas supplier, subject to such payments as may be specified. It therefore transfers some of the powers granted to the Secretary of State by the Oil and Gas (Enterprise) Act 1982 to the DGGS.

Section 23 empowers the DGGS to modify the authorization conditions imposed on a public gas supplier in cases where the latter raises no objections to the changes. If the public gas supplier does object, section 24 empowers the DGGS to refer the matter to the Monopolies and Mergers Commission (MMC).

Section 25 requires the MMC to report on the matters referred to them, and section 26 obliges the Director to modify authorization conditions to remedy any adverse effects identified by the Commission.

Section 27 enables orders (by the Secretary of State) under certain provisions of the Fair Trading Act 1973 or the Competition Act 1980 to modify authorization conditions.

Section 49 provides that, on a transfer date to be appointed by the Secretary of State, *all* the property, rights, and liabilities of the BGC are to become those of a successor company (i.e. British Gas).

It can be seen then that, as in the case of telecommunications, regulatory powers are divided between the Secretary of State, the DGGS, and the MMC. However, although the procedures for granting and amending authorizations/licenses and for enforcing compliance are broadly similar in the two cases, the powers to secure effective competition are generally weaker in the gas industry. New entry into the domestic market is blocked, and the DGGS has a duty to "enable" competition only with respect to supplies to the larger customers in the commercial and industrial markets. There is therefore little prospect that an alternative national public gas supplier will emerge to compete with British Gas in the way that Mercury has managed to do in the telecommunications industry.

The Gas Act also contains no provisions that will help to increase

competition in the market for gas purchases, although in March 1986 the Secretary of State announced that: "The Government is prepared to consider applications for waivers of the landing requirement on a case by case basis. In doing this, it will take into account considerations relating to the security of the U.K.'s gas supplies, without any presumption that exports should not take place in present circumstances." In view of the facts that (a) existing UKCS production is committed to British Gas under long-term contracts, (b) foreseeable new field developments are relatively few in number and most frequently small in magnitude, (c) gas utilities in Northern Europe have already secured the supplies they require for the next decade, and (d) direct exports would involve the construction of costly pipeline links, it is unlikely that U.K. producers will be able to take advantage of the new opportunities on any significant scale. That is, liberalization has come too late to have any substantial short- to medium-term effects, and the monopsony power of British Gas will not be materially affected for many years to come. Moreover, while the longer-term implications of liberalization are to be welcomed, it is not clear that the export opportunities will be maintained indefinitely: the ministerial statement is qualified by the "in present circumstances" condition.

British Gas's Authorisation Given the market power allowed to British Gas by the 1986 Act it might have been expected that the accompanying Authorisation, granted under clause 7 of the Act, would have been a lengthy and detailed document that attempted to establish a strict regulatory regime for the private company. In the event, however, the Authorisation is extremely brief, reflecting the Government's preference for regulation "with a light hand." Its main features are summarized below under the headings of accounting procedures, price control, common carriage, and other provisions.

Accounting procedures The first substantive condition of the Authorisation requires British Gas to prepare separate accounts for its gas supply business. This is defined to include procurement, treatment, storage, transmission, and distribution of gas for sale and safe delivery through pipes to customers in Great Britain, and the conveyance of gas for third-party suppliers. The gas supply business therefore accounts for the great bulk of the activities of the company, and excludes only such operations as appliance trading, installation and contracting activities, exploration and production, and the provision of consultancy services.

As a consequence of this provision, the DGGS will have extremely poor

accounting information upon which to base his decisions. For example, it will be difficult to assess whether or not British Gas is willing to make its transmission grid available to third-party suppliers on reasonable terms, since there is no requirement to treat the transmission system as a separate cost center. Similarly, without adequate accounting information it will be hard to judge the extent of any cross-subsidization or price discrimination that might be taking place. Hence, enforcement of the duty to "avoid undue preference," which is imposed on a public gas supplier by clause 9 of the Gas Act, will be impaired. Finally, the absence of a requirement to prepare separate accounts for regional distribution and sales systems will limit the ability of the DGGS to use company information as a basis for checking the internal efficiency performance of British Gas; the Government failed to take the opportunity to increase the number of yardstick indicators available to the DGGS.

Price control The most detailed condition of the Authorisation sets out the formula that is to determine the level of prices charged to tariff customers. In each relevant year the average price per therm is constrained to lie at or below a "maximum average price" per therm which is defined as follows:

$$M_t = [1 + (\text{RPI}_t - X)/100]P_{t-1} + Y_t - K_t,$$

where M_t is the maximum average price per therm in year t , RPI_t is the percentage change in the retail price index between October of year $t-1$ and October of year t , $X = 2$ percent,

$$P_{t-1} = [1 + (\text{RPI}_{t-1} - X)]P_{t-2},$$

except that P_1 , the value for 1986-1987, will be equal to the average price in 1986-1987 less the average cost of gas in that year, Y_t is the gas cost per therm in year t , and K_t is a correction factor per therm to be made in year t .

In effect, the formula divides the maximum price per therm into two principal components. The *gas component* Y is the average cost to the company of obtaining gas, mostly made up of payments to suppliers and including the gas levy. For gas produced from the company's own fields the price is deemed to be the market price as determined by the Inland Revenue for taxation purposes. The *nongas component* P is an amount per therm, changes in which are limited to the percentage change in the retail price index less two percentage points (X). Thus, in order to increase its profit margin, British Gas must reduce its nongas unit costs (labor, capital, etc.) by more than 2 percent per annum, a figure that presumably reflects the

Government's initial perception of the magnitude of the combined effects of scale economies and improvements in internal efficiency that might reasonably be expected over the next few years.

Since the formula links maximum prices in a given financial year to the retail price index and gas costs in that same year, in setting prices British Gas must necessarily rely on forecasts of the latter two variables. The correction factor K therefore allows for any undercharging or overcharging in one year to be corrected subsequently via a formula that incorporates an interest charge on the amount of the correction and an adjustment to take account of any change in the number of therms supplied from one year to the next. The purpose of the correction factor is simply to prevent British Gas from benefiting from forecasting errors and to provide incentives against intentional manipulation of forecasts aimed at improving financial performance (without such a factor the company would gain from consistently overestimating changes in its gas costs and in the retail price index).

Since gas tariffs are generally composed of two parts—a fixed element (the standing charge) and a price per therm—the pricing formula allows for some rebalancing of the structure of charges by British Gas. However, the Authorisation also constrains any cumulative percentage increase in the standing-charge component to be no greater than the cumulative percentage change in the retail price index from its base level in December 1985. This restriction is one of several amendments to the original draft authorization, which required only that British Gas use its best endeavors to secure the aforementioned outcome. It is designed to ensure that small consumers, for whom the standing-charge element comprises a substantial fraction of their overall purchases, are protected against substantial increases in prices resulting from changes in tariff structures.

It should be noted, however, that connection charges for new tariff customers are *not* regulated: British Gas is required by the Authorisation only to publish the principles upon which such connection charges will be established. In addition, as already explained, the pricing formula applies only to tariff customers of the company. With respect to contract customers, Condition 5 of the Authorisation states that:

“The Supplier shall, at the time when this Authorisation comes into force, publish:
 (a) a schedule of the maximum prices payable for gas supplied at that time to contract customers and shall publish a revised schedule at the time of any changes to those maximum prices; and
 (b) a general statement of the Supplier's policy as regards its willingness to enter into negotiations for prices for gas supplied to contract customers.”

Thus, apart from this minimal provision of information, contract prices are completely unregulated, even though competition from other fuels is relatively weak in several parts of the noninterruptible industrial and commercial markets.

With respect to modifications of the formula, British Gas has been granted the right to request disapplication of the price control condition with effect from a date not earlier than 1 April 1992. If it does so, the price control condition will cease to apply unless the DGGs chooses to make a reference to the MMC and the MMC concludes that abandonment of the condition can be expected to operate against the public interest. The DGGs himself has the right to modify the Authorisation at any time, including the right to vary the pricing formula, provided that British Gas agrees to the changes and the Secretary of State does not object. In the absence of such agreement, the DGGs may refer the matter to the MMC and, if the MMC subsequently proposes modifications to the condition, the DGGs is obliged to act on those proposals. In effect, then, if both the DGGs and MMC are agreed that a change would be desirable, it is possible for the pricing formula to be altered at any future date.

Taken as a whole, the pricing constraints imposed on British Gas can hardly be described as stringent. The implicit target of a 2 percent per annum reduction in nongas costs should not prove to be onerous. Some demand growth over the five-year period was predicted in the prospectus for the share issue and, given the existence of scale economies, this should lead to reductions in real unit costs even in the event that internal efficiency is not improved (see section 8.3.5). Moreover, the nationalized BGC was set a target of reducing its real net trading costs per therm by 12 percent between financial years 1982–1983 and 1986–1987 and managed to meet this target within the first three years of the four-year period.

Unlike in telecommunications, the pricing formula for British Gas also contains a “cost-plus” component: changes in the average purchase cost of gas can automatically be passed on to tariff customers, thus providing insurance for the company against movements in beachhead prices (caused, for example, by fluctuations in international oil prices). The underlying rationale for full insurance (as opposed to partial indexation of the maximum price to gas costs) is presumably that, in the short run, these gas costs are noncontrollable—long-term contracts imply that purchasing decisions in the immediate future will have very little impact on the overall average—so that customers can be given accurate signals about movements in gas input prices without seriously weakening the regulated firm's incentives to reduce costs. However, the signals provided to

customers are based upon the *average* purchase price of gas, rather than marginal opportunity costs, and only by accident will the two approximately coincide.

Common carriage The two conditions (numbers 9 and 10) of the British Gas Authorisation that set out regulations concerning the use of the company's pipeline network by third parties are both extremely short, and together they add up to only about 300 words. British Gas is required, after consulting the DGGS, to prepare a statement setting out general information for the guidance of those persons who might wish to negotiate with it for the conveyance of gas, giving examples of the prices which it would expect to be paid for such conveyance in typical circumstances, and a general description of the principal matters which it would expect to be the subject of those negotiations. Thus the DGGS has no powers to set the appropriate rates independently, although section 19 of the Gas Act 1986 gives persons interested in having their gas conveyed in this way the right to make representations to the DGGS, in which event the Act enables him, among other things, to "specify the sums or the method of determining the sums" he considers should be paid in consideration for the transport services. In principle, therefore, a pro-competitive DGGS will have some scope for encouraging new entry into nontariff markets, although, for reasons already explained, British Gas will continue to enjoy considerable powers to impede the emergence of third-party suppliers.

The Authorisation also requires that British Gas prepare a statement concerning its policies with respect to the supply of gas ("back-up gas") to a third-party supplier in the event that the third-party supplier's gas is temporarily unavailable. The intention here is to remove the barrier to new entry arising from the capacity of the incumbent dominant firm to offer customers greater security of supply than a small more specialized newcomer. Again, while the Authorisation requires only that British Gas publish guidance information about its policies, including a description of the method by which it proposes to calculate the charge for supplying back-up gas, the Gas Act empowers the DGGS, upon receiving representations from a third-party supplier, to give directions with respect to the terms and conditions of the relevant transaction.

Only time will tell whether or not these powers of the DGGS will be sufficient to encourage use of British Gas's pipeline network by competing suppliers on any significant scale. However, there are few grounds for optimism on this score. Quite apart from the incumbent firm's ability to manipulate information flows upon which terms-of-access determinations

will necessarily depend, a number of other formidable entry barriers will remain, including the inability of newcomers to enter the tariff market, the lack of regulatory constraints on British Gas's pricing policies in the contract market, and British Gas's access to gas supplies at prices below marginal opportunity costs.

Other provisions The remaining conditions of the Authorisation relate, for the most part, to a variety of disparate matters, including provision of information to the Director General and to the Gas Consumers' Council, provision of emergency service, codes of practice for tariff gas supplies and payment of bills, provision of services for the elderly and disabled, provision of information to customers on the efficient use of gas, supply of gas to public lamps (!), and the payment of fees (which, among other things, are used to finance Ofgas, the Gas Consumers' Council, and relevant references to the MMC).

The Authorisation also sets out the circumstances in which it (the Authorisation) can be revoked by the Secretary of State, the most important of which is failure of British Gas to comply with orders made under the Gas, Fair Trading or Competition Acts and/or bankruptcy of the Company. Revocation of the Authorisation is the ultimate sanction that can be applied by the Secretary of State and, since use of this power would effectively signal an almost total collapse of the regulatory regime, the consequent damages would be sufficiently great that the deterrent effects of its threatened use are likely to be significant only in rather extreme circumstances.

9.2.4 Assessment of the Framework of Competition and Regulation

The privatization of British Gas illustrates the tension in policy making between accommodating the short-term interests of major pressure groups (including the management of the enterprise concerned, new shareholders, and the firm's customers) and the longer-term benefits associated with promoting competition and establishing an effective regulatory regime. Given the political background to the U.K. privatization program, it is perhaps unsurprising to find that, in practice, the shorter-term interest group pressures have been accorded the greater weight. What is more surprising is just how little weight was, in the event, attached to competitive and regulatory objectives. To an even greater extent than in the telecommunications case, British Gas has been transferred to the private sector with its monopoly and monopsony powers intact: the philosophy of "regulation with a light hand" has been implemented in an extreme form,

and major opportunities to improve incentives in the industry have been missed.

Policy failures are evident in at least four major areas. First, there was no attempt to restructure the British Gas Corporation prior to privatization. Second, the pricing formula for tariff customers preserved the existing pricing philosophy of the BGC, which was closer to an average cost than a marginal cost tariff structure. Third, little effort was made to promote effective liberalization by encouraging actual and potential competition to the dominant supplier. Fourth, Ofgas has been granted only very limited regulatory powers, and there are considerable uncertainties surrounding longer-term developments in regulatory policy.

In each case, with the possible exception of the lack of clarity with respect to the long-term regulatory approach, the major beneficiary has been the senior management of the BGC, now the senior management of British Gas. It was management that had most to lose from restructuring, from reassessment of pricing policy, and from the diminution in market power associated with more effective competition and stronger regulation. Although it can be argued that consumers of gas also benefited in the short run from the decision to retain average cost pricing, the overall consequences of this outcome are less clear: in the longer term consumers are likely to suffer from the allocative inefficiencies associated with suboptimal pricing and market power, as well as from the absence of incentives for greater internal efficiency that would have been produced by more competition. Taking account of the impact of privatization on taxpayers and groups such as UKCS producers of gas, our general conclusion is therefore that an excessively high side payment has been made to the incumbent management to ensure managerial cooperation in the process of transferring ownership.

Restructuring The options for restructuring the BGC prior to privatization have been evaluated by Hammond *et al.* (1985). The two principal alternatives considered were the following:

- (a) regionalization, involving the creation of 12 separate regional gas companies and an enterprise (possibly a public corporation) that would own and operate the national transmission system;
- (b) separation of *all* pipeline operations, including local distribution networks, from the gas supply business, involving the creation of one or more pipeline companies that would transport gas for firms (e.g. offshore producers) competing for final customers.

Hammond *et al.* concluded that the second option was largely impractical so far as supplies to domestic consumers are concerned and that, particularly since it could be combined with vertical separation of pipeline operations and gas supply in parts of the industrial and commercial markets, regionalization offered the most attractive alternative to the sale of the BGC in its pre-privatization form (i.e. the course actually followed by the Government).

In effect, regionalization would have returned the industry to something approximating its structure prior to the 1972 Gas Act (augmented by the national transmission system) and was therefore an eminently feasible option. Relative to the creation of a private sector monopoly-cum-monopsony covering both transmission/distribution and gas supply, it would have had a number of advantages, including the following.

- (i) Reduction of monopsony power: regional distribution companies would have had to compete in the purchase of supplies from UKCS and foreign producers.
 - (ii) Increased likelihood of efficient cost-related regional price variations: distribution companies would have not been able to engage in the geographic cross-subsidization currently practiced by British Gas.
 - (iii) Enhanced effectiveness of regulation: each distribution company would have had monopoly power in its own region, but Ofgas would have been able to draw on information from several independent sources, opening up the possibility of yardstick competition.
 - (iv) Greater capital market competition: regional companies would have faced a more plausible threat of takeover than does British Gas and shareholders would have had more information upon which to base their assessments of managerial performance, both factors that might serve to improve incentives towards internal efficiency (but see section 2.2.3 for some qualifications concerning the takeover threat).
 - (v) Lower barriers to entry: vertical separation of the national transmission and area distribution networks would have put UKCS producers wishing to supply large industrial and commercial customers on a par with the regional companies when negotiating for rights to use the national high pressure pipelines, and, unlike British Gas, the common carrier would not have had direct financial incentives to exclude new entrants from the gas supply business.
- One of the problems that would have faced policy makers in the event that the regionalization option had been adopted would have been the need to revise existing gas supply contracts. This could have been accomplished

in one of a number of different ways, including the creation of a state-owned wholesale agency to hold existing contracts, auctioning off the contracts to the regional companies, and cancellation of the contracts followed by renegotiation between distribution companies and offshore producers.

Whichever course was followed, the likely consequence would have been a sharp increase in the prices paid by the regional companies via Early Southern Basin contracts. As a result, average gas purchase prices, and hence final selling prices, would quickly have been moved toward marginal opportunity costs, with beneficial effects for allocative efficiency. Moreover, the hike in prices would have facilitated new entry since established gas distribution companies would not then have access to inputs at prices that are substantially below the costs of developing new gas fields, a situation that currently has the effect of impeding potential competition.

The additional rents accruing from the revision of the Early Southern Basin contracts would also have provided a useful supplement to Exchequer revenues. The rents would have accrued directly to the state in the event that either the wholesale agency option or the auction option had been adopted. Cancellation, followed by renegotiation, of contracts would initially have left the additional returns in the hands of offshore producers, but they could readily have been clawed back via modifications to the oil and gas taxation regime.

Given the feasibility of the regionalization option and its several attractive characteristics, why then did the Government prefer to create a privately owned national monopolist-cum-monopsonist? Three major considerations appear to have been involved. First, legislation to restructure the industry, including provisions for the revision of existing contracts, would inevitably have slowed down the privatization process. Thus, although revenues from the exercise would almost certainly have been greater, they would have accrued at a later date and, given the attachment of the Government to public sector borrowing targets, the delay might have made it more difficult to attain short-term fiscal objectives. Moreover, delay might have raised doubts about the feasibility of accomplishing privatization within the lifetime of the incumbent Government (which, in the event of a Labour Party victory in the subsequent election, could have led to an indefinite postponement).

Second, the senior management of the British Gas Corporation was hostile to any restructuring of the industry. This attitude can partly be explained in terms of managerial preferences for a quieter life and for

greater company size, and partly by genuine beliefs that full integration yielded potential gains in internal efficiency. Irrespective of the underlying motivations, however, the fact of managerial hostility to restructuring would have complicated the task of privatization and contributed to delays in policy implementation.

Finally, as argued above, the revision of gas purchase contracts necessitated by restructuring would almost certainly have led to an increase in final selling prices. Thus gas consumers might have faced a significant price hike in the immediate post-privatization period. Although the community as a whole would have been likely to benefit, and gas consumers themselves would have reaped longer-term gains from greater competition and more effective regulation, this is an example of a situation where the detriments (higher prices in the short run to consumers) would have been much more visible than the benefits (including marginally lower tax rates and lower prices in the longer term). Hence the electoral consequences of restructuring might have appeared unattractive to the Government.

The decision not to reorganize the gas industry prior to privatization therefore represents a victory for political expediency over considerations of longer-term economic efficiency. In chapter 2 we examined the weaknesses of political decision making in the context of the control of public enterprise, and in chapter 4 we considered the impact of interest group pressures on regulatory processes. Both discussions are relevant to the process of privatization, which involves major political choices and can be viewed as encompassing the initial decisions about the structure of the new regulatory regime. Thus the decision not to restructure the British Gas industry can be interpreted as a response to interest group pressures from management and consumers that was motivated chiefly by electoral considerations. Economic efficiency objectives were accorded a lesser priority, with detrimental consequences that will become increasingly apparent in the longer term.

The Pricing Formula With respect to the tariff market, both the level and form of the pricing constraint are open to criticism. The gas component part of the tariff (Y) links allowable prices to the *average* cost of gas purchases and, the gas levy notwithstanding, the existence of the Early Southern Basin contracts indicates that domestic tariffs are likely initially to be below levels required for the attainment of allocative efficiency. On the other hand, the annual cost-reduction target implicit in the nongas component of the formula ($X = 2$ percent) does not appear to be very

demanding in the light of the BGC's performance in the period immediately prior to privatization.

These decisions concerning the two major components of the formula can partly be justified as an attempt to achieve a gradual movement of final selling prices towards allocatively efficient levels. As the Early Southern Basin contracts expire average purchase costs of gas will rise and, other things being equal, these average costs will move towards the cost of supplies from new fields. Further, by setting X at a relatively low level, allowable prices will rise (fall) more (less) quickly than if a more stringent target had been imposed. Thus, over the course of the next few years it might be hoped that selling prices will reach a more efficient level.

It is likely that the interests of consumer groups were a major factor in the decision not to couple privatization of the gas industry with an immediate upward adjustment of the price level. It should also be noted, however, that the decision was also very much in line with managerial preferences. Lower initial prices will contribute to further short-term increases in market share (a goal that was actively pursued by the BGC management), and the relatively generous cost-reduction target should allow the managers of British Gas to achieve a steady improvement in profit performance, thus enabling them to present themselves in a favorable light to shareholders.

While the distortions resulting from an inappropriate choice of the average price level may only be temporary, the pricing formula embodies more permanent deficiencies with respect to the incentives provided for the construction the tariff structure. To see this, suppose that British Gas serves a number of different submarkets with differing marginal costs of supply. For example, the submarkets may be defined in terms of geographic (areas of the country) or temporal (time of day or year) characteristics. For simplicity we will assume that marginal costs are independent of output, demand is a function of the average price charged in each submarket (thus ignoring both interdependent demands and the complexities associated with multipart tariffs), and demand elasticities are constant and identical in all submarkets.

The pricing formula then confronts British Gas with a constraint of the form

$$\bar{p} \sum_i q_i \geq \sum_i p_i(q_i)q_i,$$

where \bar{p} is the maximum allowable average price for all supplies. A profit-seeking firm will therefore aim to maximize

$$\sum_i (p_i - c_i)q_i + \lambda(\bar{p} \sum_i q_i - \sum_i p_i q_i),$$

yielding the first-order conditions

$$[p_i(1 - e) - c_i](1 - \lambda) + \lambda(\bar{p} - c_i) = 0,$$

where e is the inverse demand elasticity. Comparing two submarkets j and k such that $c_j > c_k$, we therefore find that

$$\frac{1 - m_j(1 - e)}{1 - m_k(1 - e)} = \frac{\bar{m}_j - 1}{\bar{m}_k - 1} < 1,$$

where $m_i = p_i/c_i$ and $\bar{m}_i = \bar{p}/c_i$. It follows immediately that $m_k < m_j$.

That is, the proportionate mark-up of price over marginal cost is lower in the lower-cost market.

Another, more intuitive, way of looking at this result can be obtained by rewriting the price constraint in the form

$$\bar{p} \geq \sum_i s_i(q)p_i(q_i),$$

where s_i is the share of total output accounted for by the i th market. Thus the (regulated) price index is calculated using weights equal to the output shares of the various markets and, by increasing outputs in low-price markets and reducing outputs in high-price markets, the firm can increase the weights attached to the former and reduce the weights attached to the latter. Since this change in weights tends to reduce the value of the index, by acting in the way described the firm can, in effect, loosen the pricing constraint.

The result can usefully be compared with the structure of mark-ups required to maximize welfare subject to a constraint on the firm's profit level: the Ramsey price structure. On the assumptions made, the latter implies that the proportionate mark-ups should be the same in all markets: $m_k = m_j$. Thus, compared with the Ramsey rule, the pricing formula gives British Gas incentives to apply higher mark-ups to higher-cost supplies and lower mark-ups to lower-cost supplies. Not only will this distort competition with other fuels such as electricity but also, over time, it will affect the investment program of the company. For example, overcharging for gas at the winter peak would eventually lead to a level of capacity provision that was suboptimally low.

In several jurisdictions in the United States regulators have been active in promoting more efficient price structures for monopolistic utilities, and the issue is considered to be an integral feature of the regulatory process. In Britain, however, little attention appears to have been paid to the problem:

as we have shown, the incentives provided by the pricing formula are perverse, and the DGGs has been afforded relatively few means of addressing the issue. One possibility is that the DGGs could take a strong line with respect to the enforcement of the "avoidance of undue preference" provision of section 9 of the 1986 Gas Act, but this might be politically unpopular and it could prove difficult to persuade the courts as to the merits of the appropriate interpretation of the legislation. While it is also possible that the issue will eventually be referred to the MMC, our interim judgment is that the initial framework of U.K. regulation is seriously deficient on this important point.

Competition Since the British Gas Authorisation effectively blocks entry into the domestic market, in the foreseeable future the only prospect for the development of increased competition in gas supplies lies in markets for larger industrial and commercial users. The Oil and Gas (Enterprise) Act 1982 formally removed certain statutory barriers to entry into this market but, because of the continued existence of other substantial obstacles to the emergence of potential competition, has had little practical effect on competitive behavior. Nor has the situation been materially affected by later Government measures that have accompanied the privatization of the industry.

The first difficulty arises from the access of British Gas to low price inputs from the Early Southern Basin fields. These supplies depress the average purchase costs of British Gas, and mean that the incumbent firm can undercut a rival that draws on supplies from a newly developed field and yet still make an accounting profit from the relevant transaction. Thus, although such price discounting might be judged to be predatory if gas inputs were priced at marginal opportunity costs, it is highly unlikely that the behavior would, in practice, satisfy any of the conventional tests for predation (e.g. price less than the average variable cost of supply).

The potential competitor's position is also weakened by two further factors. First, because British Gas is not required to account separately for the various parts of its business, it will in any case be extremely difficult to apply even conventional cost-based tests for predation. Second, U.K. competition law is lenient in its treatment of predatory behavior. If a reference is made to the MMC the best that a complainant can hope for is that, after a lengthy inquiry, the Secretary of State will, on a positive recommendation of the Commission, act so as to prevent such behavior from occurring in the future. That is, U.K. legislation is remedial rather than penal, and does little to *deter* predatory actions by a dominant incumbent firm.

Finally, control of the use of the pipeline network affords British Gas a considerable strategic advantage over potential rivals. An entrant must negotiate with British Gas for conveyance of its supplies, thus providing the incumbent with advance notice of its rival's intentions and giving the former time to offer more favorable terms to the targeted customer. Moreover, in the unregulated parts of the gas market, the DGGs has no formal powers to restrict the use of this type of localized reactive pricing strategy by the incumbent firm. For example, the legislation only requires British Gas to avoid undue preference among customers with demands of less than 25,000 therms per annum, and the company is therefore free to charge radically different prices to its various large customers.

Looked at from the viewpoint of a potential entrant then, the prospects are not encouraging. The entrant faces a dominant incumbent firm which has an "artificial" cost advantage (deriving from existing long-term supply contracts), control of the distribution network, and virtually unlimited freedom in its pricing policy. Moreover, in the absence of an effective export option, any attempt at new entry risks offending the newcomer's only alternative customer: British Gas continues to enjoy monopsony power over UKCS supplies.

As a consequence of these various problems, our conclusion is that, even in the industrial and commercial markets, the prospects for increased competition in the supply of gas are bleak. The outcome is particularly unsatisfactory because there were a number of ways in which the legislation accompanying privatization could feasibly have been used to promote greater competition. For example, it could have provided for the following:

- (i) a revision of gas purchase contracts to channel economic rents to the Government rather than to pass them on to customers in the form of lower (British Gas) prices;
- (ii) the provision of separate accounts for the various parts of British Gas's gas supply business and for the company's transmission/distribution activities;
- (iii) the allocation of stronger powers to the DGGs with respect to the prevention of predatory pricing and price discrimination in the contract market.

In the event, these opportunities were not exploited and, in opting for light regulation of British Gas, the Government has created a market structure that is inimical to the development of greater competition.

Regulation Although the regulatory framework established for the

gas industry has numerous weaknesses, the resulting structures are, fortunately, not permanently fixed. Regulatory policy can be expected to evolve over time and, as the Director General of Telecommunications (DGT) has shown, an active regulator can use the discretion afforded by the initial regime to remedy some of the legislative deficiencies. Nevertheless, any proclivities of the DGGS to foster competition and strengthen regulatory controls *will* be checked by the initial conditions: there is no equivalent to Mercury in the industry, entry based on the introduction of new technologies and products is much less likely than in telecommunications, and the formal powers of the DGGS are not great.

In the course of time, many of the features of the regulatory framework, including the pricing formula, will no doubt be reviewed by the MMC. In arriving at its judgments, the MMC is required to apply very widely drawn "public interest" criteria, and there is therefore substantial uncertainty attached to the recommendations that it might make. With respect to pricing, it is extremely likely that cost data, supplied by British Gas itself, will be one of the factors influencing future decisions, and the record of monopolies and mergers cases examined by the MMC suggests that the rate of return on capital will play a significant role. However, the precise weight that will be attached to the rate of return (as compared with other performance indicators) remains unclear.

To the extent that British Gas's average costs do have a positive influence on allowable prices in subsequent indexation periods, there will be some attenuation of incentives for cost reduction. As a review of the pricing formula becomes imminent the company might tend to hold back on cost-saving projects for fear that the consequence of cost reductions will be less favorable prices in the subsequent period. At this point, relatively long gaps between reviews can have negative consequences (see section 4.2.2): the gains from manipulating cost levels upwards in the period immediately preceding the review are greater the longer the duration for which the subsequent prices are expected to hold.

Expectations that the rate of return will be taken into account when fixing regulated prices also lead to incentives for cross-subsidization by British Gas. The company might be tempted to depress its overall rate of return by charging lower prices in the unregulated industrial and commercial markets in the hope of thereby being allowed higher prices in the regulated tariff market. By failing to require separate accounts for the regulated and unregulated parts of British Gas's business, the Authorisation serves to encourage this type of strategic behavior (because the behavior is more difficult to detect). Further, the strategy is made more

attractive by both its deterrent effect on potential competitors and its contribution to the managerial goal of increasing the company's share of the total energy market.

Despite the fact that the rate of return on capital is likely to be an influential factor in the regulatory review, it would be wrong to conclude that overinvestment will inevitably be a major problem in the industry. The MMC's public interest guidelines are an open invitation to consider adjustments of prices towards shorter-run marginal costs. Hence, the management of British Gas will necessarily have to consider the possibility that, in the event of the emergence of excess capacity, it will not be able to recover the full economic costs of investment expenditures. In addition, as we have shown in section 4.2.3, if short-run marginal costs are an influential factor in regulatory decisions, British Gas may have incentives to limit its capital expenditures since, by so doing, it can exert an upward pressure on allowable prices. Finally, to the extent that the pricing formula gives the company incentives to overprice at demand peaks, this too will be a force pushing in the direction of underinvestment in the longer term (although it can be argued that, since under public ownership British Gas tended to overinvest and to underprice peak supplies, the shorter-term implications of these directional shifts may be by no means detrimental).

Whether or not underinvestment will eventually be a major problem depends to a large extent upon expectations about the role that will be accorded to the rate of return in the MMC's deliberations. The introduction of an explicit rate-of-return criterion into these deliberations would help mitigate some of the difficulties but would not, in itself, be a panacea: much depends upon the level at which the allowable rate of return is set. Suppose, for example, that a "fair" rate of return is defined that is only *slightly* above the cost of capital, that the firm will never be allowed prices that would lead to performance significantly exceeding this level, and that prices will be adjusted below the level implied by the "fair" rate in the event of excess capacity. The outcome is then likely to be underinvestment. In favorable states of the world (demand high in relation to capacity) the firm cannot earn more than the (relatively low) allowed rate of return, whereas in unfavorable states (demand low in relation to capacity) it can expect to earn significantly less. Hence there is an obvious bias in favor of limiting capacity in order to reduce the probability of unfavorable states. On the other hand, if a more generous rate of return was allowed, the incentives for "rate-base padding" (see section 4.2.1) would have a stronger positive effect on capital expenditures, which would more substantially offset the bias arising from demand uncertainty.

What these various arguments suggest is that, in its present form, the U.K. regulatory regime might well lead to significant suboptimalities in investment programs. Our own judgment is that, in the longer term, the problem is more likely to be underinvestment than overinvestment. In addition to the factors already mentioned, this view is based on three further considerations.

- (i) The presence of substantial uncertainty as to the evolution of the future conduct of regulatory policy is itself a factor tending to raise the private cost of capital to a regulated firm above the corresponding social cost.
- (ii) Although it is now probably fairly low, the nonzero probability of renationalization of the industry on terms unfavorable to shareholders (e.g. in the event of a return to political power by the Labour Party) serves to depress the anticipated return on new investment. Similarly, and perhaps of much greater importance, a future non-Conservative government might attach a lower weight to profitability criteria in regulatory decisions.
- (iii) The monopoly position enjoyed by British Gas, coupled with high barriers to entry into the industry, imply that any tendency to underinvestment is unlikely to be checked by competitive threats from actual and potential competitors.

We conclude that the most fundamental weaknesses of U.K. regulatory policy are associated with an excessively short-term view of the underlying economic issues. The Government has been content to focus upon the initial post-privatization period, leaving many fundamental issues unresolved. The resulting absence of any clear durable bargain between Government and the regulated firm is to be regretted, as also is the failure to promote greater competition (the benefits of which would also have been of a longer-term nature). What has happened is that one of the major deficiencies of the U.K. control system for nationalized industries—preoccupation with short-term political issues (see chapter 5)—has been duplicated in the policy framework set for the regulated privately owned gas industry.

Recent developments Given the short time that has elapsed since the privatization of British Gas, there is as yet little evidence concerning the actual impact of the new regime established in 1986. The first report of the DGGs was issued in February 1987 (Ofgas, 1987), but, as was only to be expected, it was largely devoted to a general review of issues and priorities. In the summer of 1987, however, a number of events occurred that, in different ways, touch upon problems that we have discussed in this section.

The first was a dispute between Mr James MacKinnon, the first DGGs, and British Gas concerning the DGGs's rights to acquire information relevant to the pricing formula. In June 1987 British Gas announced that it intended to cut average prices to domestic customers by 4.5 percent in the tariff period commencing 1 July. A major factor in this decision was the fall in gas purchase costs that had occurred as a result of the fall in world oil prices (see the figures in table 9.3), and, since this was relevant to the calculation of the maximum allowable price (via the gas cost component Y of the pricing formula), the DGGs asked British Gas to provide him with details of the terms of the various supply contracts. British Gas refused, reportedly on the grounds that the information was commercially sensitive, and stated that the DGGs was entitled only to a single figure: the company's own estimate of the average purchase price in the relevant tariff year. This position was maintained, despite an offer by Mr MacKinnon to examine the data on British Gas's own premises. The DGGs then threatened legal action and, subsequently, at its first annual shareholders' meeting, British Gas announced that it would, after all, be willing to provide Ofgas with the information requested.

What is remarkable about the dispute is that it should have arisen at all. If British Gas believed that it had a right to withhold relatively objective data pertaining to a major component of the pricing formula, the conflict signals how much more difficult it will be for the DGGs to obtain information that is more susceptible to manipulation and is not directly relevant to the determination of the maximum allowable average price. For example, the DGGs will need cost breakdowns to assess whether or not British Gas is unduly discriminating among tariff customers and to give rulings on terms and conditions for the conveyance of third-party gas through British Gas's pipelines, yet neither the 1986 Act nor the initial Authorisation explicitly requires the company to provide such information. In short, the dispute highlights the relatively weak position of the DGGs, and continuing difficulties with respect to the acquisition of information can be anticipated.

The second event of note was the proposed acquisition by British Gas of an approximately 33 percent stake in Bow Valley Industries, a Canadian oil and gas company, together with an option to increase its holding to up to 51 percent by the end of March 1990. The proposal, announced in early August 1987, did not involve any fundamental competition or regulatory policy issues, but Bow Valley does have a 14 percent stake in the UKCS Brae Field, which has total initial proven and probable reserves of 118 million barrels of oil and 275 billion cubic feet of gas. The chief executive of

British Gas declared at the time that the acquisition was the first of what might be many such transactions and indicated that oil and natural gas exploration and development would be an area of major importance for the company in the future.

The issue raised here is the extent to which British Gas will be allowed to expand by acquisition into upstream activities in the UKCS, reversing the process that occurred when the company's oil interests were transferred to Enterprise Oil prior to the flotation of the latter in 1983. Vertical expansion would strengthen British Gas's already formidable hand in its dealings with other UKCS producers, and any significant move in this direction would warrant investigation by the MMC. In addition to its effects on competition, there are also concerns about the implications of vertical integration for the incentives provided by the price control formula. Because gas purchase costs can be passed through into retail prices, British Gas might have weaker incentives than an independent producer to be cost efficient in its exploration and development activities. Moreover, since transactions between the production and distribution/sales parts of the company would not be at arm's length, there would be scope for manipulating transfer prices in negotiations with the Inland Revenue.

Finally, the summer of 1987 saw a major dispute between the Board of Directors of British Gas and some of the company's larger industrial customers. The latter were disgruntled both by what they saw as excessively high industrial gas prices—particularly in relation to the input prices obtained by their overseas competitors—and by the wide disparities in prices charged to different firms. Following complaints to the Office of Fair Trading and the European Commission in Brussels about British Gas's pricing policies in the contract market, a group of industrial customers nominated Sir Ian MacGregor, former chairman of both British Steel and British Coal, for a seat on the Board of Directors. The move was strongly opposed by Sir Denis Rooke, the Chairman of British Gas, who argued that it would be wrong for a director to be appointed to look after one section of customers. In the event, British Gas's shareholders supported the Chairman and Sir Ian was not elected to the Board.

Whatever the merits of the industrial customers' case with respect to the average level of gas prices, the incident serves to highlight the existence of significant pockets of market power in the contract market. The customers concerned felt that they could not easily switch either to other fuels such as electricity, coal, and oil, or to other suppliers of gas. Indeed, if these alternatives had been perceived to be available it would be difficult to explain why the complainants would have risked offending a major

supplier by behaving as they did. Although there are good reasons, explained above, for doubting that industrial gas prices are in fact high in relation to the marginal opportunity cost of supply, the industrial customers do, nevertheless, have a point. The existing regulatory regime leaves British Gas with a free hand in the contract market and provides little assurance that third-party gas suppliers will be able to obtain access to the pipeline network on reasonable terms. In such circumstances, industrial users will rightly feel that they are subject to the discretionary behavior of British Gas and, whether or not the incumbent firm chooses to exercise its market power to raise prices significantly above costs, the outcome will be perceived to be unfair. Thus, irrespective of its likely effects on economic efficiency, stronger regulation, aimed at establishing and enforcing "fair rules of competition," would be a desirable development.

It is also noteworthy that, in pursuing their case, the industrial customers pressed their complaint with the Office of Fair Trading and the European Commission, and not with Ofgas. This was because the contract sector of the market is subject to general competition law. The DGGS has virtually no jurisdiction in the area and does not have the power to refer matters relating to gas supply to contract customers to the MMC. Given the interdependences between the contract and tariff sectors, the existence of significant market power in parts of the former, and the expertise that will gradually be acquired by Ofgas, we believe that this division of responsibilities is misguided and potentially damaging. Regulation would be more effective if the DGGS were granted wider powers to make references to the MMC and to modify those conditions of the Authorisation that are concerned with behavior in the contract market. Alternatively the existing division of responsibilities could be ended by placing all regulatory policy in the hands of the Office of Fair Trading.

9.3 The Electricity Supply Industry

The 1987 Conservative Election Manifesto contained a commitment to privatize the electricity supply industry (ESI) but did not provide any detailed information as to how and when this was to be done. Given the size of the industry and the complexity of the issues involved, it is likely that the preparatory stage of the policy process will be of longer duration than in most of the earlier privatizations and that the transfer of ownership will not occur until around the end of the decade. Because of the anticipated timetable, therefore, our analysis in this case will largely focus upon the broad structural issues raised by the prospective privatization of the

industry, rather than upon the fine detail of the policies that might be implemented.

Our discussion comprises five sections. The history and structure of the industry in Britain—we omit discussion of Northern Ireland, where the picture is somewhat different—is briefly described in section 9.3.1. Existing regulatory structures and policies are examined in section 9.3.2, while section 9.3.3 is devoted to an analysis of problems surrounding policies to promote competition in the industry. We then turn, in section 9.3.4, to the central topic of the discussion: an analysis of the various structural options that are available to the Government. Finally, section 9.3.5 contains a summary assessment of the prospects for privatization.

9.3.1 History and Structure of the Industry in Britain

Like the gas industry, prior to nationalization electricity supply in Britain was divided amongst a large number of municipal undertakings and commercial companies, each of which was centered on a particular area of the country and, if privately owned, was extensively regulated. Private ownership was, however, much more common on the distribution side of the industry, public utilities having been dominant in electricity generation from a relatively early date, and regulatory activities were more centralized than in gas. Thus, for example, the Electricity (Supply) Act 1919 established the Electricity Commission to promote, regulate, and supervise the supply of electricity on a national scale, while the Electricity (Supply) Act 1926 set up the Central Electricity Board to construct and operate a national system of interconnected generating stations.

Although interwar legislation introduced a substantial measure of public ownership and control over the generation and supply of electricity in bulk, it had little impact on the distribution of electricity to final customers: in the mid-1940s there still existed about 560 separate suppliers, of which approximately one third were privately owned. Full nationalization only occurred in the wake of the Electricity Act 1947, which established the Central Electricity Authority (CEA) as a public corporation responsible for the generation and supply of bulk electricity and created fourteen Area Boards, each constituted as a separate public corporation responsible for the distribution of electricity in its own region.

Following the 1947 Act the organization of the industry became highly centralized: the CEA, for example, was entrusted with general control over the Area Boards with respect to policy and finance. It was not long, however, before moves were afoot to amend this structure. The Electricity Reorganisation (Scotland) Act 1954 reduced the number of Area Boards to

twelve by setting up two independent Scottish Boards, each vertically integrated in the generation and distribution of electricity. A little later the Herbert Committee (1956), established to inquire into the working of the industry, criticized the organization of the industry on the grounds that (a) it was overcentralized and (b) it would be better to separate the executive and supervisory functions of the CEA. Partly as a result of the Herbert Committee's recommendations, the Government introduced legislation (the Electricity Act 1957) to restructure the industry, and it is this Act that has determined the principal organizational features of the industry for the subsequent 30 years.

In brief, the 1957 legislation implemented the Herbert Committee's recommendation that the functions of generating and supplying bulk electricity should be separated from the functions of coordinating and controlling the supply system as a whole. As a consequence the Central Electricity Generating Board (CEGB) was established to handle the former tasks. The Area Boards were also accorded greater autonomy, particularly with respect to financial matters. However, although the Herbert Committee had envisaged the continuation of the CEA as a regulatory watchdog body, none of whose members would be drawn from the Electricity Boards, the Government balked at this recommendation. The principal reason for this reluctance to adopt the Committee's position appears to have been an unwillingness to relinquish direct ministerial control over the industry: the CEA would have had substantial powers of supervision and decision, and ministerial influence would have been relatively indirect, operating via powers of appointment and the capacity to make parliamentary orders.

Hence, in place of the CEA, the Government opted for the establishment of the Electricity Council, which is a forum where the general policy of the ESI is discussed and which consists of a chairman, two deputy chairmen, the chairman and two other members of the CEGB, the chairmen of the twelve Area Boards, and up to three other members directly appointed by the Secretary of State. The Electricity Council is therefore a federal body, entrusted with consultative and deliberative functions rather than with powers of direction, control, or supervision.

The Electricity Act 1957 was concerned with reorganization of the industry in England and Wales only; Northern Ireland and Scotland continue to have their own independent boards. As already noted, in the Scottish case the two organizations—the South of Scotland Electricity Board and the North of Scotland Hydro-Electric Board—each have responsibility for both generation and distribution activities, although they

jointly operate a power-pooling scheme for the use of generating capacity.

Consumers' interests in England and Wales are represented by 13 distinct organizations. The Electricity Consumers' Council, set up in 1977, operates at the national level while 12 Area Electricity Consultative Councils, one for each Area Board and established by the 1957 Act, are concerned with regional issues.

It can be seen therefore that, in England and Wales, the organization of the industry provides for vertical separation between the generation and transmission of bulk electricity (undertaken by the CEGB) and distribution and retailing activities (undertaken by the Area Boards, which are also responsible for contracting and appliance marketing operations). The CEGB is required by statute to meet directly the electricity requirements of British Rail and, with the authority of the Secretary of State for Energy, it provides direct supplies to a further small and restricted group of industrial customers. It also purchases bulk supplies of electricity from the South of Scotland Board and Electricité de France. These various transactions, however, account for only a small fraction of the CEGB's revenues and costs (although the possibility of increasing the capacity of cross-channel transmission links, to take advantage of excess generating capacity in France, offers prospects for significant future growth) and, for the most part, its activities can be viewed as the generation and supply of electricity to meet the requirements of the Area Boards. In turn, the Area Boards, while purchasing some electricity from private producers and being allowed in certain circumstances to generate their own power, obtain almost all of their supplies from the CEGB. In principle, therefore, the relationship between the CEGB and the Area Boards, considered as a group, is one of bilateral monopoly. In practice, however, the role and composition of the Electricity Council facilitates coordination between the two sides of the industry, with the CEGB in the dominant position, and in many respects the resulting behavior is little different from that to be expected from a single fully integrated public corporation.

The terms on which electricity is sold by the CEGB to the Area Boards are set out annually in the former's Bulk Supply Tariff (BST). Direct sales to customers by the CEGB have also generally been on terms linked to the BST charges. Although, viewed from the perspective of the ESI as a whole, the BST tariff rates are internal transfer prices, they are nevertheless the key pricing instruments of the industry. By and large the Area Boards structure their own retail tariffs around the BST rates, albeit with a good deal of simplification and averaging, since these rates are the principal determinants of the Area Boards' own cost structures.

To date, there has been little use of the publicly owned national and regional transmission/distribution grids by private producers of electricity. Much of the privately generated electricity emerges as a by-product of other production processes—for example, a firm might make use of steam from its manufacturing plant to drive a generator—and is consumed on site. Until recently entry into the market was restricted by statute: the Electric Lighting Act 1909 prohibited persons other than Electricity Boards from commencing to supply or distribute electricity as a main business, while the Electricity (Supply) Act 1919 restricted the establishment and extension of generating stations.

As part of its legislative program to promote liberalization in energy markets, however, the 1979–1983 Conservative Government sought, in the Energy Act 1983, to reduce the barriers to entry facing private producers of electricity. Among other things, the Energy Act repealed the aforementioned provisions of the 1909 and 1919 Acts and required the Area Boards to purchase electricity from persons other than the CEGB at rates to be set out in published tariffs, known as Private Purchase Tariffs (PPTs). In other words, the Act created a “put option” for private producers at the designated rates. In addition, the legislation required the CEGB and the Area Boards to make their transmission and distribution networks available to others on terms which were to be set out in published tariffs, and which were to be calculated so as to yield only a normal rate of return on the capital involved.

We will analyze the Energy Act in more detail in section 9.3.2 below, but it can be noted immediately that, as yet, the legislation appears to have had very little effect on the structure of the ESI. Private producers have not come forward in any numbers either to make use of the electricity grids to transport supplies directly to customers or to sell electricity to the Area Boards under the terms set out in the PPTs. Nor is there any sign that entry threats have substantially intensified. As a consequence, the generation and distribution of electricity in Britain has continued to be dominated by a group of public corporations that faces very little competition from either established or potential rivals.

9.3.2 Regulation of the Electricity Supply Industry

The ESI currently operates within the policy framework laid down by the 1978 White Paper on nationalized industries (see section 5.4). Thus, for example, the Government has set out the following targets for the industry as a whole:

- (i) a financial target, defined in terms of operating profit as a percentage

return on average capital employed, calculated according to current cost accounting conventions, and equal to 2.75 percent for the three years from 1985–1986;

(ii) an annual external financing limit, which in 1986–1987 called for a repayment of loans totalling £1.416 billion;

(iii) a required pretax real rate of return of 5 percent on new investment as a whole;

(iv) performance objectives, of which the most important has taken the form of a target reduction in real controllable unit costs of 6.1 percent over the period from 1983–1984 to 1987–1988.

Subject to these various constraints, and in line with the provisions of the 1967 and 1978 White Papers, the ESI's public corporations have attempted to construct tariff structures that broadly reflect long-run marginal costs. Thus, the 1987–1988 BST contained two fixed charges, two capacity charges (reflecting marginal capital costs), and no less than 36 unit rates (reflecting marginal operating costs) that differentiate between time of day, day of the week, and season of the year. While there have been a number of criticisms of the detailed implementation of marginal cost pricing policies (see Slater and Yarrow, 1983), it is fair to say that the ESI has made a more serious attempt than most of the other nationalized industries to meet this aspect of public policy objectives. However, one major policy failure is worth explicit mention: successive Governments have used their influence over the terms of the CEGB's purchase contracts with British Coal to shield the domestic coal industry from international competition. The contracts between the two public corporations have forced the CEGB to purchase its principal input, accounting for around 40 percent of its total costs, at rates that are typically well in excess of international market levels and have limited the extent to which it can make use of imported coal. The extent of the subsidy can be gauged from table 9.5, which shows estimates of the premiums over the Rotterdam spot market price that were paid by the CEGB between 1979 and 1983. The consequences of this policy are that accounting costs in the ESI have been inflated above opportunity cost levels and, since it is the former that influence the level and structure of electricity prices, incorrect cost signals have therefore been passed forward to electricity consumers.

Perhaps the most interesting aspect of the financial regime imposed on the ESI in recent years is the similarity of many of its features to those embodied in the regulatory framework adopted for the privatized gas industry. As argued in section 5.4, the 1978 White Paper shifted the

Table 9.5 Estimates of the percentage premium paid for coal by the CEGB

Year	1979	1980	1981	1982	1983
Premium (percent)	14.3	36.4	8.1	16.3	35.4

Source: Molyneux and Thompson (1987).

emphasis of policy objectives from pricing and investment guidelines derived from first-best welfare principles to increased profitability and cash flow. Thus, between financial years 1980–1981 and 1986–1987 the financial target was increased from 1.7 to 2.75 percent and the external financing limit was reduced from +£187 million to –£1,416 million. The resulting impact on the industry has been akin to the type of change that could have been expected in the event of privatization: management has been confronted with greater pressures to improve financial performance.

Similarly, the performance target covering reductions in real controllable unit costs is analogous to the X factor in the gas pricing formula. For the ESI, the major cost component that is classed as noncontrollable is its expenditure on coal inputs. Hence, if the ESI were set a pricing formula of the $RPI - X + Y$ form, where Y was linked to the average purchase price of coal, the outcome would not be dissimilar to that implied by an appropriate combination of the financial and cost-reduction targets. Unless accompanied by regulation of the rate structure, however, such a pricing formula approach would represent a step backward with respect to the incentives for temporal price differentiation (for the reasons outlined in section 9.2.4).

Against the view that the current regulatory structure for the publicly owned ESI is similar to that adopted for the privately owned gas industry, it might be argued that, under public ownership, the financial pressures on management are less severe than those that would be demanded by the capital market. For example, both the financial target (2.75 percent) and the required rate of return on investment (5 percent) appear low in comparison with comparable private sector rates of return. The situation is, however, less clear cut than it might appear at first sight. In the first place, as a result of excess capacity in the industry as a whole and of an inefficient plant mix (partly the consequence of unanticipated movements in fossil fuel prices in the 1970s), the book value of assets at replacement costs is almost certainly much greater than the underlying economic worth of the assets. Second, despite the rate-of-return criterion, investment programs are in practice largely constrained by the need to agree external financing limits with the Government, and, given the pursuit of tight fiscal policies, it is likely that the "implicit" required rate of return for the public sector has been in excess of 5 percent over the last few years. In any event,

because of the existence of excess capacity the number of new investment projects initiated by the industry has been relatively limited during this period, and capital expenditures have been little affected by the choice of target value. With growing demand, however, investment decisions are again becoming more important, and we will discuss the implications of privatization for the industry's cost of capital in section 9.3.4.

In reality, with the exception of the period covering the 1984–1985 coal miners' strike, the cash flows generated by the ESI over the past five years have been substantial. For purposes of comparison it can be noted that in 1979–1980 it was estimated that a CCA rate of return of around 1.25 percent was equivalent to an HCA return on average net assets of 9.8 percent (Monopolies and Mergers Commission, 1981a, para. 3.8), and that in 1985–1986 operating profits plus depreciation amounted to £2.749 billion, equal to about 25 percent of turnover, while the Government benefited to the tune of over £1.9 billion in the form of interest payments on debt, corporation tax, and the external financing limit. To produce these cash flows the Government, via its control of the financial constraints, has forced prices above short-run marginal costs.

If, therefore, the industry is to be privatized, there does not appear to be a strong case for an initial hike in prices on allocative efficiency grounds, despite the apparently low level of the current financial target. Nevertheless, in November 1987 the Government announced that it would again be increasing the financial target for the ESI in England and Wales to 3.75 percent in 1988–1989 and 4.75 percent in 1989–1990, the net effect of which is likely to be an increase in real electricity prices of around 8 percent over the two years. The reason given for the increase was that prices would have to be raised to attract adequate finance for the major power station construction program that is anticipated in the 1990s. However, if this argument is taken at face value, it implies a remarkably pessimistic view of the cost reductions that are likely to be attained by a privatized industry, particularly since it is known that coal input costs are of the order of £750 million above the level that could be achieved if the domestic coal market was liberalized (see section 9.5). Moreover, it is by no means clear why consumers should be asked to pay in 1988 for an investment program that will not be in place for several more years—unless, that is, the policy decision also reflects an appreciation of the potential underinvestment problems that are associated with privatization (see section 4.2.3). The most cynical view of the policy announcement is, of course, that it simply reflects an attempt to increase the sales proceeds that will be realized when the public corporations come to be transferred to the private sector.

However, whatever the motives for the decision, it is safe to conclude that it does not show privatization in a particularly favorable light.

Had the recommendations of the Herbert Committee concerning the role of the CEA been adopted in the 1950s, the similarity between the regulatory regimes of the publicly owned ESI and the privately owned gas industry would have been even greater: the CEA would have functioned as an independent supervisory agency acting at arm's length from Government departments and from the regulated firms, in very much the way that Ofgas and Oftel operate currently. Ironically, therefore, the regulatory model adopted for gas and telecommunications in the mid-1980s is similar to one that was rejected for the ESI by a Conservative Government in the mid-1950s.

As the trend in cash flows to the Exchequer shows, the tightening of financial constraints on the ESI since 1979 has certainly had the desired effect of improving financial performance. On the other hand, the implications for allocative and cost efficiency are less clear. Excess capacity in the industry, overpriced coal inputs, and gas pricing policy all point to the conclusion that the level of electricity prices has been suboptimally high when judged against allocative efficiency criteria. With respect to internal efficiency, although (real) unit controllable costs have recently been reduced by 4.6 percent between 1983–1984 and 1986–1987, the record of productivity performance has not been impressive. Between 1978 and 1985 total factor productivity increased by an average of 1.4 percent per annum, little different from the rate achieved between 1960 and 1978 which itself was slightly below the manufacturing average over this earlier period. Given the strong productivity gains in U.K. manufacturing during the 1980s, recent improvements in the ESI therefore appear to have lagged behind those in other major industrial sectors of the economy. Thus the substantial improvement in financial performance does not appear to have been matched by corresponding gains in internal efficiency, an outcome consistent with the argument developed in sections 5.5 and 5.7 that public corporations with market power have been allowed to meet tighter financial targets by raising prices rather than by reducing costs.

It is with respect to this last point that significant differences between the regulatory frameworks for the publicly owned ESI and the privately owned gas industry *do* emerge. Unlike the electricity corporations, British Gas is unable to raise its prices to tariff customers above the levels specified in the price control formula (i.e. the price level, rather than the rate of return or the EFL, is the policy instrument), and, coupled with pressures emanating from the capital market to increase profits, this may produce greater