British experience of electricity liberalisation: A model for India?

Stephen Thomas[1]

The "British model" of electricity reform has been the model for many countries worldwide. However, the industry structure and mechanisms in Britain have changed in response to new evidence and pressures in the sector. This paper examines the track record of electricity reform to understand why the model was changed, what the results were and whether the high reputation of the British experience is justified.

1 Introduction

The reforms to the British electricity industry, the 'British Model', have been the model for reforms to electricity industries worldwide.[2] The industry structure and mechanisms in Britain have changed since 1990 and the electricity industry is now significantly different to the ideal that other countries copied. However, the reputation of the British reforms remains high. This paper examines why the model was changed, whether the reputation of British experience is justified and whether these good results can be maintained. It focuses particularly on economic criteria, although reliability is a key issue that must be addressed in any overall evaluation of the British experience.

2 What is the British model?

There were six main elements to the 1990 British Model:

- Creation of a wholesale spot market as the main price-setting arena;
- Creation of retail competition so that all consumers can choose their electricity supplier;
- Corporate separation of network activities from activities that would be market-driven;
- Corporate separation between generation and retail supply;
- Adoption of incentive regulation to set the prices for monopoly activities; and
- Sale of publicly-owned assets to private investors.

The first four elements are interdependent. Retail competition would make no sense if generation was a regulated monopoly. However, rate-of-return regulation can be used to regulate the monopolies in a liberalised industry model, as has been the case in Norway. Privatisation is also not integral to reform. In the Nordic countries, much of the reformed industry remains in public hands, while in the USA, most of the industry was in private ownership before liberalisation. The central criterion for judging the results in Britain is: have the reforms resulted in the creation of efficient retail and wholesale markets? It was the promise that replacing monopolies by competition would lead to efficiency improvements and price reductions that justified the British reforms. The question can be divided into three parts:

- Is the industry corporate structure competitive;
- Is the wholesale electricity market efficient; and
- Is retail electricity competition resulting in an efficient allocation of costs?

3 Motivation for the British reforms

There was little apparent need for reform in 1987. Service was reliable, prices were in line with European countries, the industry was profitable and investment needs could be readily financed. However, there were three strong non-sector objectives that influenced the decision: generation of government revenues; widening of share ownership; and breaking trade union power.

3.1 Generation of government revenues

When the privatisation programme was launched around 1980, Britain was in deep recession. Revenues from privatisation allowed government spending to be maintained. When electricity privatisation was mooted, the British economy had recovered, but the political value of income that could reduce income tax was large. The Treasury's objective was to generate about £5bn per year from privatisation in 1987. The sale of the electricity companies was spread over several years with a total yield of about £15bn, far more than any previous privatisation.

3.2 Widening of Share Ownership

The public flotation of the utility industries such as telecoms (1984), gas (1986) and water (1989), included sale of some of the shares to the public. The public assumed that the shares would be profitable and the flotations were over-subscribed several times over. The use of public flotations meant that the government had to guess the value of the companies and this guess had to err on the low side to minimise risk to investors. The difference between the flotation price and the price on the first day of trading ranged from 20 per cent for the power generators to 86 per cent for British Telecom [Wright and Thompson 1994: 55]. The government ensured the companies would be profitable by limiting the extent of competition and by setting easy regulatory targets. However, by 1987, the public backlash against companies seen as privatised monopolies meant that the British electricity industry had to have the appearance of a competitive industry but transitional measures limited the scope for competition for eight years after privatisation.

3.3 Breaking Trade Union Power

Much of the power of the trade union movement lay in large publicly owned utilities. These had monopoly powers over public services, so strike action would quickly have an impact. Breaking up these large companies and introducing competition was bound to reduce union power. Support from the workforce for strikes that could harm a company operating in a competitive market would be difficult to gain. If the companies were split up on privatisation this would fragment union power. In addition, private owners could impose conditions on the work force that it would have been politically difficult for publicly owned companies to impose.

4 Is the industry corporate structure competitive?

The ideal British Model structure would have required the industry to be split into two competitive activities, generation and retail supply both with a number of competing companies; and two monopoly activities, high voltage transmission and low voltage distribution. A number of factors meant that it was impossible in 1990 to introduce this ideal structure:

- The unfamiliarity to investors of some activities making the companies difficult to value and sell;
- The difficulties of setting up a large number of new companies;
- The problems of introducing retail competition; and
- The need to introduce transitional protection for the British nuclear and coal industries.

The CEGB was split into two privatised generators, National Power and Powergen, a publicly owned nuclear generator, Nuclear Electric, and a transmission company, National Grid Company (NGC). The 12 regional distribution/retail companies became Regional Electricity Companies (RECs).

4.1 Generation

The government's commitment to nuclear power prevented the creation of a competitive field of generators. The government believed that Britain's nuclear plants, then providing 15 per cent of electricity, could be privatised if they were 'sheltered' in a large company owning two thirds of the capacity. To provide countervailing power, the rest of the plants would be placed in one other company. In the event, the shelter of a large company was insufficient to make the nuclear plants attractive to investors, but this became clear too late in the process for the structure to be reconsidered.[3] The fossil fuel plants were allocated so National Power had 30GW, Powergen had 20GW and Nuclear Electric was had 8GW.[4] About half Nuclear Electric's income came from a subsidy and the generation market was therefore effectively a duopoly.

The RECs were allowed to acquire up to 15 per cent of their power from their own plant. In the 'Dash for Gas' from 1990-92, they bought about 10GW of plant. This allowed the RECs to diversify their businesses and reduced their dependence on the duopoly. The principle of separating retail and generation was compromised further by the decision to allow National Power and Powergen to supply power to final consumers in the competitive part of the market.

The Regulator has intervened continually to increase competition in generation, twice, requiring the ‘duopoly’ to sell plant. In 1996, National Power and Powergen had to sell 6GW of their plants [Offer 1995] but at the expense of compromise to the principle of separation of generation and retail, the plant being sold to a REC, Eastern Electricity. However, when National Power and Powergen tried to take over RECs in 1996, they were blocked by the government [Department of Trade and Industry Press Release 1996]. In 1998, the government allowed them to take over retail businesses on the condition that they both sold 4GW of their plant. How far this reversal was a pragmatic decision based on recognition that the principle of de-integration had already been lost and how far it represented a decision to allow the market to integrate is not clear. One explanation is that the separation of distribution and retail would have left the retail sector vulnerable. A retail business has few assets other than customer loyalty and if the retail businesses were forced to operate as separate entities, they might have proved too unstable. If they could not be integrated with distribution, integrating with generation was the only viable option.

The two regions of Scotland are now part of a British market and the 14 retail regions of Britain are owned by five companies. National Power got into financial difficulties and in 2000, was split into a UK business, Innogy (trading as Npower), and an independent power producer, International Power. Innogy and Powergen were taken over by German companies, RWE and E.ON, in 2001. EDF entered the market taking over RECs and buying some of the capacity released by the duopoly. TXU, a US utility that built an integrated business around its ownership of the Eastern REC and the purchase of generating plant, made poor power purchase deals, got into severe financial difficulties in 2002, and was taken over by E.ON. Centrica (the retail business of the former national gas company) has about 24 per cent of the household electricity market but only a small share of the market for large electricity consumers [Ofgem 2003].

Nuclear Electric doubled the output of the newer nuclear plants. A government review [Department of Trade and Industry and the Scottish Office 1995] recommended that the newer nuclear plants (9GW) be privatised and the nuclear subsidy be removed. In 1996, British Energy was privatised. The older plants were left in public ownership in a new company, Magnox Electric, later absorbed into the nationally owned nuclear fuel cycle company BNFL. British Energy prospered initially, but by 2000, falls in the wholesale electricity price had eroded profits and by autumn 2002, it had to receive a government loan of £650m to stay in business. The Magnox plants are a small part of BNFL’s overall operations. BNFL is also insolvent and the Magnox plants lost £159m in fiscal year 2002/03.

Table 1 Ownership of generating capacity: 1990 and 2004

1990 (Capacity GW)		**2004 (Capacity GW)**	
National Power	30	British Energy (nuclear: insolvent)	9.6
Powergen	20	*Innogy (RWE)	8.0
Nuclear Electric	8	*Powergen (E.ON)	8.3
		*Scottish & Southern	5.3
		*Scottish Power	4.7
		*EDF	4.7
		BNFL (nuclear: insolvent)	2.7
		*Centrica	2.2
		Others	9.2
		Plant repossessed by banks etc	7.9
		Plant for sale	6.3
		TOTAL	68.9

Source: *Author’s research.*

Notes: Companies with generation and retail supply are marked *.

The generation market appeared competitive by 2004 (see Table 1). Eight companies had more than 3 per cent of the market and no company had more than 15 per cent. However, 40 per cent of capacity is owned by companies that are financially distressed or has been repossessed by banks.[5] EDF, E.ON and RWE are doing very well in the British market making a significant proportion of their profits there.[6]

4.2 Retail supply, distribution and transmission

The RECs had to make an accounting separation between distribution and retail and were protected from takeover by golden shares for five years. When the golden share expired, all except one was taken over. In 1997, the Regulator became concerned about the scope for cross-subsidy between distribution and retail. A significant proportion of staff and systems were common to both businesses. The Regulator feared that companies would cross-subsidise retail from distribution choking off competition. He required a legal separation of the businesses although they could remain under common ownership [Offer 1998a]. Distribution and retail have little in common in terms of skills – retail requires buying and selling a commodity while distribution requires the maintenance of a network. As a result, many of the owners chose to split the businesses. By 2004, the distribution businesses of half of the regions of England, Wales & Scotland were owned by companies other than the owner of the retail business. EDF, Scottish Power, Powergen and Scottish & Southern operate in both distribution and retail. Innogy has not bought distribution, while PPL, Mid-American Energy Holding, and United Utilities have sold their retail businesses.

A priority for the government in 1990 was to ensure that transmission was not owned by a generator, as this would have led to fears that access to the network would not be fair. The National Grid Co was owned by the RECs, with limitations on how far they could influence its policy. In 1995, they were required to sell their shares. In 2003, NGC merged with its gas industry equivalent, Transco, to form National Grid Transco (NGT). The strong regulatory requirement for de-integration of retail and distribution and the independence of NGT mean that all generators and retailers have equal access to networks on non-discriminatory terms.

4.3 Assessment of the structure

The decisions to allow integration of generation and retail and to allow concentration mean the structure is not competitive and there seem few policy options to improve it. There is little independent power to give liquidity to the wholesale market. Of the six integrated companies, the parents of the three foreign owned companies are much larger than the three British-owned companies who could prove vulnerable to takeover. In a few years, the British market could be dominated by three or four companies. These companies would have no interest in competing against each other and there will be little prospect of new entrants. The one success with the structure has been the separation of the network from the competitive activities. However, given the uncompetitive structure of generation and retail, this is a hollow victory.

5 Is the wholesale electricity market an efficient one?

The creation of a highly competitive wholesale electricity market was the centrepiece of the British reforms. In 1990, the cost of generation comprised 60 per cent of the retail price of electricity. Most of the rest was accounted for by network charges; distribution (25 per cent) and transmission (5 per cent). There seemed little reason to expect privatisation would significantly reduce the network charges. There is no evidence to support the hypothesis that privately owned electric utilities are more efficient than publicly owned utilities, indeed, what little evidence did exist suggested the opposite [Pollitt 1995]. It was the vision of generation companies competing with each other every half hour of every day that promised significant price reductions.

5.1 The Power Pool

The ‘Power Pool’ operated from 1990 until 2001. Its main principles were:

- Supply and demand would be balanced every half hour;
- All generators would have to make a successful bid into the Pool to operate their plants;
- The Pool price would be set by the highest successful bid and paid to all successful bidders; and
- Retailers would have to buy all their supplies from the Pool.

The attraction of a compulsory market was that it would make barriers to entry for generators and retailers low. Generators just had to generate at below the market price to sell their power and retailers bought from one Pool on the same terms as each other. However, this advantage was lost by the extent of bilateral contracting allowed. Such contracts were drawn in a form that meant that generators and suppliers were paid the contract price regardless of the actual Pool price: any difference between the Pool price and the contract price was settled bilaterally between the generator and the supplier – a contract for differences (CfD). The major practical problem with the Pool was the capacity payment mechanism, which was abused by the generators [Thomas 1997a]. This led to an unpredictable Pool price that generators and retailers had no confidence in and they relied on contracts not linked to the Pool price for most of their sales and purchases.

5.1.1 Compromises to the Pool

Government ministers have admitted that an objective of electricity privatisation was to break the power of the mining union [Ridley 1991; Walker 1991; Parkinson 1992; Lawson 1992], but British-mined coal was produced at above world price and if generators had been free to purchase where they wanted, the British coal industry would have collapsed with severe social results. The government required the generators to buy coal from British Coal for three years. The volumes corresponded to about the same as before privatisation, about 65 per cent of generation, and prices were to fall to world market levels by the end of the contract. The government required the RECs to buy the power generated by British coal under CfDs and the RECs could allocate this power to the captive market.

The contracts were renewed for five years in 1993, so that by 1998, 40 per cent of generation was covered and real prices were 30 per cent lower than in 1990. The RECs had to buy the output from this coal and could allocate it to the captive market. The effects of the coal contracts were:

- 70 per cent falling to 40 per cent of generation was taken out of the wholesale market from 1990-98;
- The generators were guaranteed good profits from these contracts as the sale price for the power allowed the coal price reductions to be kept as profit [Thomas 2000];
- Small consumers, who were allocated this expensive power, were paying, by 1997, about 30 per cent more for their generation than non-captive consumers; and
- The British mining industry was destroyed. The implausibility of long-term contracts for British coal beyond 1998 meant that investment in new mining capacity could not be justified.

The operating costs of the nuclear plants were double the expected market price so the government had to introduce a consumer subsidy accounting for half Nuclear Electric's income to allow the continued operation of the plants. The RECs had to buy all the nuclear output. The government wanted the subsidy to be open-ended but the European Commission judged it an unfair state aid and required it be removed by 1998. The 'Fossil Fuel Levy', had to go to all forms of generation that did not use fossil fuels. A small proportion was paid to a renewables programme and since French and Scottish generators argued that exports to England & Wales were provided by nuclear or hydro plants, the subsidy was paid to imports from France and Scotland.

In 1990 it was expected that the seven Magnox plants would be retired by 2000. The Advanced Gas-cooled Reactors (AGRs) were very unreliable and some were expected to be closed. The one unit (Sizewell B, a Pressurised Water Reactor) under construction would not be able to recover its costs and there was pressure to abandon it [MacKerron 1996]. But by 1995, Sizewell B had been completed and seemed likely to operate reasonably reliably and output of the AGRs had nearly doubled. This meant that the AGRs and Sizewell B seemed able to cover their operating costs from receipts from the Pool allowing these plants to be privatised in 1996. The effect of this protection for nuclear on the wholesale market was:

- 15 per cent, rising to 25 per cent of supply provided by nuclear power was out of the market;
- 10 per cent of demand was supplied by heavily subsidised imports; and
- Nuclear and imported power was cheap to retailers because they did not pay the subsidy and they allocated these sources to the competitive market.

The RECs were uncomfortable buying most of their power from the duopoly. New gas-fired plant was expected to generate at below the price offered by the duopoly so the case for the RECs to build new power plants seemed strong. The RECs ordered about 10GW of plant from 1990-92, contracted to themselves for 15 years and with matching take-or-pay base-load gas supply contracts at fixed prices. By 1994, the gas market price had halved leaving this plant the most expensive in the market [Thomas 1997b]. The result of the REC's power plants was that by 1998, about 20 per cent of electricity demand was met by gas-fired plants that were out of the market. This power was expensive and was allocated to the household market.

5.1.2 Assessment of the Power Pool

If the contribution of the coal, nuclear, the RECs' plants and imports is added up, more than 95 per cent of RECs' needs were supplied from sources that did not compete in the Pool. But by 1997, the coal contracts were nearing an end, the oldest nuclear plants were due to close, imports were no longer subsidised. As a result, there appeared to be space in the wholesale market for new generators, as the price of power from new plants (then less than 2p/kWh) was well below Pool prices (then about 2.5p/kWh) and the price most power was actually bought and sold at (more than 3p/kWh). Encouraged by the success of Enron 'wheeling and dealing' in wholesale markets, new entrants ordered gas-fired 'merchant' plants that would survive on Pool receipts. The New Labour government stopped this burst of ordering, but by then, about 10GW of new plants was under construction by companies other than the duopoly and the RECs.

Two decisions removed the basis for the merchant plants. Bids by the duopoly for supply businesses were allowed and the retail businesses were quickly bought by generators who would use their own plants to meet their needs. The government announced that the Pool would be replaced [Offer 1998b] by the New Electricity Trading Arrangements (NETA). The market would not be compulsory and it was expected that more than 90 per cent of power would be traded under long-term confidential contracts. This meant that generators had to find a specific buyer for their power either in the spot market or under long-term contracts. Merchant plants had poor prospects in such a system and some of the merchant plants got long-term contracts, some were abandoned and some were sold to integrated companies.

The detailed design of the Power Pool was poor, but the concept of a universal Pool was not tested [Green 2003; Newbery 2004]. Thomas raised doubts that a compulsory Pool in a de-integrated market would provide security of supply as there was no mechanism to balance supply and demand [Thomas 1994]. The fact that the wholesale price was above the cost of entry from 1990-98 meant that there were strong incentives to maintain capacity in service. The adequacy of the Pool in terms of supply security would only have been tested if the Pool price had fallen to a more appropriate level in that period.

5.2 NETA

The key points about NETA were the decision to allow vertical integration and the expectation that the spot market would account for less than 10 per cent of sales. This meant that NETA would not be the highly competitive spot market forecast in 1990 when it was claimed that 'the grid company will be calling up the generators which offer the cheapest energy'. NETA proved costly and took longer to develop than expected. It went live in 2001 with the cost of development and of running the system for the first five years totalling about £770m [National Audit Office 2003].

5.2.1 NETA in theory and practice

Until 24 hours before time of consumption, power is traded via long-term confidential contracts. From 24 hours to 1 hour, power is traded on open power exchanges. Deals in the spot market are bilateral and are settled at the offer price. At 1 hour, generators inform the Transmission System Operator (TSO) of the plants they will operate and retailers declare the amount they expect their consumers to consume. The imbalance between the sum of the intentions of the generators and retailers, and the TSO's more accurate forecast of demand is met by the TSO buying power or paying generators not to generate in the Balancing Market (BM).

A price index for the spot market is published but it does not reflect the cost at which most power is traded. In the second half of January 2004, the typical daily volume was 8MWh, less than 1 per cent of demand.[7] There have been a number of practical problems. Starting up a thermal power station takes several hours and has high costs. Retailers that underestimate their demands and generators that do not fulfil their contract output will have the balance bought for them by the TSO at a potentially punitive System Buy Price. Generators that cannot easily forecast their output, for example wind generators or co-generators, will be penalised. NETA favours large integrated companies that can forecast demand accurately and that have spare plant available to cover plant breakdowns.

The NAO estimated that wholesale prices fell by 20 per cent between the introduction of NETA in March 2001 and October 2002 and by 40 per cent from 1998-2002 [National Audit Office 2003]. The Regulator and government claimed credit saying it was the expectation of the impact of NETA and the efficiency of the market that forced prices down. These claims are hard to justify. More plausible explanations are: the end of the high-priced coal contracts in 1998; the surplus of capacity that resulted from the new power plant orders in 1997; and the over-contracting for fuel on take-or-pay contracts leading to dumping.

Another possible factor explains the collapse of the non-integrated generators. Reductions in the spot price and to the price of short-term contracts had a severe effect on such companies. British Energy then had weak long-term contractual cover. In 2002/03, the average spot price was £15.48/MWh while its average sale price was £18.30/MWh. In 1998/99, its average selling price had been £26.40/MWh, so income for British Energy had fallen by 30 per cent. For the integrated companies, their income did not fall because they did not pass the price reductions on to final consumers [National Audit Office 2003: 3].

5.2.2 Security of supply

The government and the Regulator are against measures, such as capacity payments, that try to ensure that there is sufficient capacity. There was a surplus of capacity in 2002 reflecting the surge of orders of 1997. This surplus contributed to the steep fall in wholesale electricity prices. By September 2003, low market prices meant that most non-integrated generators were financially distressed and a large amount of plant was mothballed. The TSO was forced to warn of a possible shortage of generation for winter 2003/04 and encouraged generators to bring plant back into service. This happened and the potential problem averted. However, the existence of a large volume of mothballed plant cannot be assumed, market signals must stimulate new investment. This raises two issues: will the price signals be timely and will financiers be willing to fund investment? Large power plants need about five years from start of planning to first power, so there is a serious risk that price singles will emerge too late leading to very high short-term prices and perhaps power blackouts.

Nearly all the investment in generating plant in UK since 1990 has been an economic failure:

- The plants built by National Power and Powergen lost large amounts of money;[8]
- The plants built by the RECs were high cost and these high costs were passed on to small consumers contributing to the inflated price they pay for power;
- The £3bn of consumers' money invested in the Sizewell B nuclear power plant was lost when it was essentially given away in the privatisation of British Energy
- The companies that built plant in the second 'dash-for-gas' of 1997 fared badly; and
- The American companies that entered the market in 1999-2001, buying about 12GW of existing plants were all in serious financial problems by the end of 2001.

The British wholesale market is not competitive, but it is risky. Financiers will need evidence that new investment will not be as disastrous as it was from 1990-2002 if they are to finance new plants. The companies for which investment risk may be tolerable are large integrated ones. They have some assurance of a market for their power and if it is expensive, the cost can be passed on to residential consumers. It is not clear whether integration of generation and retail will deliver supply security. But an oligopoly of weakly regulated, integrated retailer-generators passing on high cost power to small consumers would be a high price to pay for security of supply.

5.2.3 Assessment of NETA

There is a vicious circle with the spot market. There is a lack of liquidity in the spot market because prices are not consistent and prices are not consistent because of a lack of liquidity. This vicious circle is compounded in Britain by the dominance over the market by integrated companies that have no interest in promoting a liquid markets. Without a liquid markets, the barriers to entry for new generators and retailers are high. A Pool has theoretical advantages over a voluntary spot market. It should reduce the barriers to entry for generators and retailers and the lack of a balancing market makes it easier for small generation sources that cannot easily predict their availability. But, neither model guarantees security of supply. Various forms of capacity payment have been introduced in other electricity wholesale markets, but it is doubtful whether a system can be devised that guarantees sufficient capacity is available without compromising the requirements of a free market: free entry and exit.

6 Is retail electricity competition resulting in an efficient allocation of costs?

Retail competition was introduced in three stages: large consumers in 1990; medium consumers in 1994; and small consumers in 1998/99. If the Pool worked as expected, with all wholesale power bought at Pool-related prices, it is hard to see how retail competition could have been offered benefits to small consumers because retailers' costs only represent about 5 per cent of small consumers' bills. For large and medium consumers, a price reduction of only one or two percent is worthwhile, but for small consumers small percentage savings are unlikely to cause much interest. The costs of introducing competition for medium and large consumers, for example metering, are small compared to their overall bill. It seems therefore likely that such consumers will have the incentive and the capabilities to take advantage of market-opening to reduce their costs.

Data from 1998 showed that the price reductions won by large consumers had been paid for by small consumers. Retailers allocated expensive purchases to the captive market and cheap purchases to the competitive market. Small consumers were paying 30 per cent more for the generation part of their bill than large consumers (see Table 2). The Regulator claimed that full retail competition would mean that all consumers would pay the same for generation. The NAO report shows this did not happen. Retailers are still allocating expensive power purchases to the residential market. Worse, while supply was still a monopoly, the retailers could only pass on the actual cost paid for generation, now prices are unregulated and retailers can add on any profit margin they like. Power UK (2002) reported that wholesale prices went down by 35 per cent from January 1999 to January 2002, but the price paid by large consumers for their generation and retail elements of their bill went down by 22 per cent, while the amount paid by small consumers had gone up by 5 per cent.

Table 2 REC Purchase Costs – 1996/97

	Average price (p/kWh)	Quantity (TWh)
Franchise consumers		
Coal contracts	3.92	71.7
IPP contracts	3.84	28.9
Other contracts	3.71	34.3
Average franchise purchase costs	3.85	134.9
Non-franchise purchase costs	3.00	80.4
Average total purchase costs	3.54	215.2

Source: *Offer 1997.*

Given the failure of the wholesale market, if electricity companies are to be subject to competition, it will be through consumers switching regularly to the cheapest supplier. Large consumers do this and have reduced their costs as a result. If small consumers did this, the switching costs would be huge. The British Energy Minister, Brian Wilson said in May 2003 'The benefits of price falls must not be restricted to those who switch, not least because if everyone starts to switch, the costs of administering this will outstrip the savings' [Power UK 2003]. However, small consumers will not do this because they do not have the resources, the confidence or the incentive.

7 Regulation[9]

7.1 The Regulator

A Director General of Electricity Supplies (DGES) was appointed in 1989 to regulate the electricity industry, with the support of an Office of Electricity Regulation (Offer). Offer had a staff of about 220 (about half working on consumer representation) and an annual budget of about £10 million. In 1998, the DGGS (gas regulator), Callum McCarthy, was also appointed DGES and Offer merged with Ofgas to become the Office of Gas and Electricity Markets (Ofgem). In 2000, the decision-making body became the Gas and Electricity Markets Authority and consumer representation was given to a new body, Energywatch. In 2003, Ofgem's operating costs were £38 million and it employed 312 people. Ofgem does not divide its budget between gas and electricity. Its main cost in 2003 was staff costs (40 per cent) with payments to contractors accounting for 19 per cent. Ofgem divides its work into four categories:

- Making markets work effectively. This accounts for about 57 per cent of the resources;
- Regulating monopoly businesses intelligently. This uses 28 per cent of the resources;
- Meeting its social and environmental obligations. This uses about 9 per cent of the resources;
- Developing Ofgem's effectiveness and efficiency. This accounts for 5 per cent of the resources.

The number of staff working on regulation appears to have increased by about 50 per cent and the budget has more than doubled. The suggestion, widely touted at the time of privatisation, that regulation would be 'light' and that the need for a specific regulatory body would disappear once markets were established seems to have been hopelessly optimistic.

7.2 Setting monopoly prices

One of the most notable results of the British reforms is the reduction in prices for use of the network. These make up about a third of the total retail price of electricity and prices had almost halved by 2002. Price regulation was to be carried out using 'incentive' regulation: the 'RPI–X' formula. Under this, the supplier of a monopoly service is allowed to increase its prices in line with inflation (RPI is the Retail Price Index) minus X per cent. If 'X' was 2, prices would go down in real terms by 2 per cent. The 'X' factor, set initially by government would subsequently be revised by the Regulator at five year intervals. If the company improves its efficiency by more than X per cent, it keeps the extra earnings, if it does not, its profit fall. The Regulator would have no interest in how the targets were met, by productivity improvements or by capital investments.

The 'X' factors set by the government were lax. For example, the distribution company SEEBOARD was allowed to increase its real prices by 3 per cent in the first five years. Most mature industries would expect to improve their efficiency by about 2 per cent a year, or about 8 per cent from 1990 to 1995. By 1995, there was a considerable backlog of efficiency improvements the privatized companies could make and this was a factor in the subsequent price reductions.

The incentive methodology was not viable and the only way to regulate prices in a capital intensive industry such as electricity, water or gas was to relate prices to the amount of investments made. From 1993 in the gas industry and 1995 in the electricity industry, all 'X' factors have been set using a variant of rate-of-return methodology. The results are presented as an 'X' factor, but the methodology is far from that proposed by Littlechild [Littlechild 1983]. The main price reductions occurred in the period after the methodology changed, in 1995 for distribution (32 per cent) and 1997 for transmission (32 per cent).

The new formula adopted to calculate the allowed income over the five-year forward period from the date the review was to apply from is:

Allowed income=(value of existing investments-depreciation+new investments)*allowed rate of return+operating costs

The process to determine the values in this formula takes two to three years and is a major and growing element in the workload of the Regulator.

7.2.1 Value of existing investments

To explain the steep reduction in monopoly prices, it is necessary to focus on the value given to investments made before privatisation. To give the right price signals to consumers, the appropriate value for these assets would be their accounting value. However, given that the companies were sold for about a third of their accounting value, giving the new owners a full rate of return on the accounting value of the assets would have given them unearned profits. The Regulator therefore set the value of the pre-privatization assets at the sale price of the companies. Given that return on assets represents a large proportion of the allowed income of the companies, if two-thirds of the value of the assets is written off, large price reductions will follow. This decision had two important consequences:

- As the written-off assets are replaced by new assets purchased at full price, the value of the asset base will have to increase and prices will tend to rise again to pay for them.

- The price reductions were paid for by taxpayers, who lost money because assets they owned were sold for a small fraction of their value.

7.2.2 New investments

The utilities present investment plans to the Regulator who carries out detailed assessments using consultants and eventually arrives at an agreed value of investments that can be made. Use of the new formula carries the same risk (the Averch-Johnson effect) as traditional rate-of-return regulation. It provides an incentive to over-invest, because the more investments that are made, the more profits the companies make. In practice, the utilities always invest less than they are allowed to invest (typically they invest about 90 per cent) and earn extra profits until the next review when the value of the forecast investment programme can be replaced by the actual amount invested. They also delay investments till the end of the regulatory period so they can earn a return before they make the investments. The Regulator has a difficult decision to make when companies under-invest. If he penalises them, the companies will have no incentive to find efficiency gains that will reduce the amount they have to invest, but if he does not, the companies will make unearned profits. The major weakness of the system for estimating future investment needs is that it requires the Regulator to effectively make investment decisions.

7.2.3 Allowed rate-of-return

The allowed rate-of-return has been reduced since 1995 when the distribution price review allowed companies a 7 per cent real return on assets. Recent reviews have used 6.25 per cent. This term should be related to the company’s cost of capital, which is determined by the riskiness of its business and its performance. If Regulators clamp down on underinvestment and on assets that are not cost-effective, the market will see the company as risky and will increase the cost of capital. If the company performs poorly and its credit rating falls the Regulator must decide whether to pass on the additional borrowing costs, penalising consumers for the company’s poor performance. Or he must make the company pay from its profits, damaging its financial status and putting the company at risk. Any benefits from tougher regulation may be lost because consumers will have to pay for them with higher rates of return.

7.2.4 Operating costs

Most observers attribute the price reductions to improved static efficiency. However, the rate-of-return and operating cost elements of the companies’ incomes are comparable in size and it is clear that no conceivable improvement in static efficiency would have been sufficient to account for more than a small element of the price reductions. The Regulator is now using statistical and engineering methods to rank distribution companies by their efficiency and is using these to set targets to force the least efficient companies to come up to the standards of the best.

8 Why have prices gone down[10]

In 1988-89, the government increased electricity prices by 7 per cent more than required by the electricity industry, to fatten up the industry for the market [Yarrow 1992]. There are two dominant elements of the price reductions from 1990-2003 of about 30 per cent and neither was the result of the operation of markets. The removal of the nuclear subsidy in 1996 reduced prices by 10 per cent. The main part of the price reductions came about because of the reduction in monopoly prices. A House of Commons report [House of Commons Trade and Industry Committee 2004] found ‘there is a danger that there is currently insufficient investment in the network to replace in a planned and orderly way equipment which is reaching the end of its life.’ The Chair of the Committee said ‘the supply system had been "gold-plated" before privatisation but companies had been living off that cushion for too long’ [Guardian 2004].

There were major cost reductions for generators after privatisation, but little if any of these cost reductions were passed on to consumers:

- Real fossil fuel prices paid by British generators have fallen by 50 per cent for coal and 30 per cent for gas from 1990-2001 [Wright and Thomas 2001];
- The electricity industry was privatised for about a third of its asset value so that the generators bought their power stations for only a third of their value; and

- More efficient generating plant, the combined cycle gas turbine (CCGT) became available.

9 Developments from 2004 onwards

Until 2004, these reservations about the British Model were hypothetical. However, in 2004, these risks became real with the sharp end of price reductions for monopoly services and large overall price increases.

9.1 Consumer price rises

In 2003, the electricity retailers began to increase prices. From the beginning of 2004 to March 2005, electricity prices for small consumers rose on average by 15 per cent while gas prices (the same companies control the gas market) increased by 18 per cent (see Table 3). Inflation is less than 2 per cent so these are large real increases in the price of energy for household consumers. Whilst world fossil fuel prices have increased substantially, consumers are entitled to be suspicious of these increases on a number of grounds. First, the companies have all increased their profits from their UK operations, for example, Centrica's profits for 2004 were 18% higher than the previous year despite the fact that it lost more than one million consumers during the year. Second, many of the companies have long-term contracts for gas and coal that are not very sensitive to world fuel prices. Third, the Regulator now has no say in the prices the companies charge: they charge what the market can bear. Fourth, world fuel prices seem a 'one way street'. From 1990-2002, prices paid for fossil fuels by UK companies fell by 30-50 per cent but little of this was passed on to consumers, yet fossil fuel price increases were immediately passed on. The reality may be that now the independent generators are out of the market, the six remaining companies can build their profit margins.

Table 3 Price rises for residential electricity & gas consumers from January 2004 (date/% increase)

	Electricity				Gas			
				% increase from 01/04				% increase from 01/04
NPower	05-04/5.8	10-04/7.6		13.8	02-04/5.2	10-04/11.8		17.6
Powergen	01-04/6.9	11-04/8.9		16.4	01-04/4.9	09-04/3.1	11-04/9.6	18.5
EDF	03-04/6.7	08-04/3.8	01-05/5.4	16.7	03-04/4.6	08-04/3.5	01-05/8.1	17.0
S&SE	07-04/3.7	02-05/6.7		10.6	07-04/9.1	02-05/9.0		18.9
SP	03-04/5.0	10-04/9.0		14.5	03-04/5.0	10-04/11.8		17.4
Centrica	01-04/5.9	09-04/9.4		15.9	01-04/5.9	09-04/12.4		19.0

Source: *Author's research.*

9.2 Network prices

In a mature industry, it might be expected that real costs can be reduced by about 1.5-2 per cent per year, resulting over five years in real price reductions of 8-10 per cent. The 'X' factor set for transmission prices in 2001 only required the transmission company to reduce its prices over the following five years by 6 per cent [Ofgem 2000]. In 2004, the distribution charges to apply from 2005 for the following five years were announced. The settlement varied from region to region, but, on average, the companies were allowed a small price increase in the first year with X factors of zero for the following four years [Ofgem 2004]. This is a clear indication that the cost of replacing the pre-privatisation assets is now having a major impact on network costs and for the next decade or more, few if any price reductions in network costs are likely.

10 Conclusions[11]

In 2003/04, the 'honeymoon' period for the privatised British electricity industry came to an end and the price reductions from 1987 onwards were almost wiped out in only a year. The good results up to 2002 were based on three factors:

- Good luck, particularly extremely advantageous fossil fuel markets;
- A significant improvement in the performance of the British nuclear power plants; and
- A transfer of resources from tax-payers to electricity consumers.

The criterion on which the reforms must be judged is whether efficient markets have been created. On this criterion, they have failed. The wholesale market is not competitive. Confidential contracts and self-dealing within integrated generator/retailers dominate wholesale purchases leaving the spot market with no liquidity and unreliable prices. The failure to develop a competitive wholesale market places the onus on the retail consumers to force competition on the industry. Large consumers can do this and have done well from liberalisation. But, these gains have come at the expense of small consumers and, unless government strengthens regulation at the expense of markets, this exploitation will get worse. The industry is dangerously close to an oligopoly with a veneer of competition and there will be an increasing need for consumers to pay for the replacement of written off pre-privatisation assets at full price.

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[1]Steve Thomas, University of Greenwich. Stephen.thomas@gre.ac.uk

[2] There are three electricity systems in the UK. The largest covers England & Wales, where the British Model was applied. The Scottish system is synchronised to that of England & Wales and was supplied by two companies that were privatised as regional, vertically integrated companies with little scope for competition. The system covering Northern Ireland is geographically isolated. It was privatised in 1992 with some restructuring but minimal scope for competition.

[3] In evidence to the Energy Select Committee, the Secretary of State for Energy, John Wakeham said 'If I was starting from scratch I would not have decided to split the CEGB fossil stations into two companies' [House of Commons Select Committee on Energy 1990].

[4] The Scottish nuclear plants were withdrawn from the privatisation and put in a new company called Scottish Nuclear.

[5] Since this data was calculated, a significant proportion of the 'distressed' capacity has been bought by the six integrated companies, tightening even further, their grip on the wholesale market.

[6] In 2002, EDF's UK operations made up 9 per cent of EDF Group sales but 37 per cent of net profits [EDF 2002]. In 2003, RWE reported that Innogy was a 'major contributor to improved operating results (see Hhttp://www.rwe.com/app/presse/Anzeige.aspx?id=3576797H). Associated Press Worldstream reported that for E.ON: 'Nine-month revenues rose 33 percent, to €33.29 billion (€38.28 billion) from €25.05 billion, the company said, with much of the increase coming from Powergen and latest acquisition Ruhrgas of Germany'.

[7] Volumes and prices for the UKPX are published fortnightly in a newsletter, Power in Europe (McGraw Hill).

[8] In 1998, Powergen renegotiated gas contracts at a cost to the company of £535m. In 1999, National Power announced provisions for losses on its gas contracts of £759m.

[9] For a fuller account of regulation, see Thomas (2001) and Oliveira & Tolmasquim (2004).

[10] A counterfactual analysis of electricity prices in Britain since 1990 found that 'observed prices are indeed significantly higher than they would have been had privatisation not occurred' [Branston 2000].

[11] For earlier analyses of the costs and benefits of electricity reforms in Britain, see Surrey (1996) and Newbery & Pollitt (1996).