The UK Experience: Privatization with Market Power

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8 February 1999

1. Introduction

The UK has three quite distinct electricity supply industries (ESIs) in the three different jurisdictions of England and Wales, Scotland and Northern Ireland. In England and Wales (with a population just over 50 million and a peak demand of just over 49 GW) the industry was under public ownership from 1948-90, and for most of this period, the Central Electricity Generating Board (CEGB) operated all generation and transmission as a vertically integrated statutory monopoly, with 12 Area Boards acting as regional distribution monopolies. The CEGB had interconnectors to Scotland and France, with whom it traded electricity. Scotland (with a population of 5.1 million and peak demand of 5.6 GW, including exports of 800 MW to England) has always retained a degree of autonomy (in law and government) within Britain, while England and Wales are normally treated as a single jurisdiction.[1] In Scotland there were two vertically integrated geographically distinct utilities, combining generation, transmission, distribution and supply, one serving the north, the other serving the south. Northern Ireland (with a population of 1.7 million and peak demand of 1.5 GW) is physically separate from the mainland, and the grid connection with Eire in the south had been severed by terrorist activity so that it was a small isolated system. It included all four functions within a single vertically integrated state-owned company, Northern Ireland Electricity (NIE).

2. Restructuring and ownership changes

The *Electricity Act 1989* divided the CEGB, with its 74 power stations and the national grid, into four companies. Sixty per cent of conventional generating capacity (40 power stations with 30 GW capacity) were placed in National Power, and the remainder (23 stations of 20 GW) were placed in PowerGen. The 12 nuclear stations with 8 GW capacity were placed in Nuclear Electric, and the high tension grid, together with 2 GW of pumped-storage generation,[2] were transferred to the National Grid Company (NGC). These four companies were vested (ie created) as public limited companies (plcs) on March 31st 1990, at the same time as the twelve distribution companies, now known as the Regional Electricity Companies (RECs). NGC was transferred to the joint ownership

[1] The Labour Government elected in 1997 granted greater autonomy to Scotland, and accepted the wishes of the 50.1% of the voting residents in a referendum to create a separate Welsh assembly.

[2] Turbines pump water up to a hill-top reservoir during off-peak periods, allowing generation in peak periods or to provide rapid response to meet short-falls in generation.

of the RECs, and the RECs were sold to the public in December 1990. Sixty per cent of National Power and PowerGen were subsequently sold to the public in March 1991, with the balance sold in March 1995. Competition in generation was introduced by requiring all generators (public and private) to sell their electricity in a wholesale market, the Electricity Pool.

The original plan was to place the 12 nuclear stations in National Power, which had been given the bulk of the fossil generation in the hope that the combination would be financially viable, but at a late stage it became clear the nuclear stations were not saleable at a reasonable price. They were transferred to Nuclear Electric and kept in public ownership until 1996. The pumped-storage generation of NGC was separated and sold to Mission Energy at the end of 1995, and the RECs sold their shares in NGC when it was floated on the Stock Market, also at the end of 1995.

The *Electricity Act 1989* also set out a time-table for introducing competition into supply. At privatisation, the 5,000 consumers with more than 1 MW demand were free to contract with any supplier (or directly from the Electricity Pool), but all other consumers had to buy from their local REC, which had a franchise monopoly. In 1994 the franchise limit was lowered to 100 kW, and another 45,000 customers were free to choose their supplier. Starting in late 1998, the remaining 22 million customers have that right and the REC franchises will finally end. The Act also created the Office of Electricity Regulation, Offer, and the Director General of Electricity Supply, the DGES, to regulate the natural monopoly wires businesses of NGC and the RECs, and to set price caps, which would be reset at periodic reviews every 4-5 years.

The Scottish system, with about 10 GW capacity, was also restructured on March 31, 1990, when the North of Scotland Hydro-Electric Board became Scottish Hydro-Electric, and the non-nuclear assets of the South of Scotland Electricity Board were transferred to Scottish Power. Both were privatised as vertically integrated regulated utilities in June 1991, free to sell into the English market, using the English Pool price as the reference price for Scottish trading and operating under the same system of regulation.

The publicly owned nuclear stations were restructured again when the 5 newer Advanced Gas-cooled Reactors (AGRs) with about 5 GW were transferred from Nuclear Electric together with the 2 AGRs from Scottish Electric to British Energy. British Energy was then privatised in 1996. Nuclear Electric's 7 remaining old Magnox reactors with about 3 GW (which had negative net value) were transferred to the publicly owned British Nuclear Fuels Ltd, the fuel (re)processing company.

Northern Ireland was different again, where the ESI is governed by the Electricity Order SI 1992 No. 231, which has similarities with but some important differences from the British regulatory system (MMC 1997, ch 4). The four power stations (with rather less than 2 GW, and a peak demand of 1.5 GW) were sold in a trade sale to three different companies in 1992. NIE, which now just contained transmission and distribution, was sold to the public in 1993. There is no supply competition as all electricity is sold to the Power Procurement business of NIE under long-term contracts.

Thus England and Wales were almost completely unbundled and restructured before privatisation. Subsequent reforms attempted to complete the process as NGC sold its generation and was sold by the RECs, though at the same time the RECs were integrating into generation. Scotland contains two vertically integrated regulated utilities who can compete for customers (and sell in England and Wales). Northern Ireland has separated generation from the wires businesses, but transmission, distribution and supply are combined in a regulated franchise monopoly. NIE's electricity prices were about 23% higher than on the mainland in 1996, and the gap was expected to widen, because of the lack of competition in generation and the protected long-term contracts with the generators. Scotland is the farthest from the ideal of separating generation from transmission, and perhaps as a result, supply competition is relatively weak. Consequently, there are pressures for further restructuring in both Scotland and Northern Ireland.

After privatisation, almost all of the RECs became joint investors with Independent Power Producers (IPPs) in building gas-fired combined cycle gas turbine (CCGT) generating stations, whose high efficiency, low capital costs, modest economic scale, and use of cheap fuel, made them attractive competitors to the predominantly coal-fired generation of National Power and PowerGen. The next major structural change occurred in 1996, when under regulatory pressure, National Power divested 4 GW and PowerGen divested 2 GW of coal-fired generation, all to Eastern Group, one of the largest RECs, which thereby became a major generator with significant distribution assets. In August 1998 PowerGen agreed with the Department of Trade and Industry (DTI) to divest two more large coal-fired power stations (4 GW) in return for permission to merge with the US-owned English REC East Midlands. National Power has offered to sell Drax, at 4,000 MW one of the largest coal-fired power stations in Europe, and equipped with flue gas desulphurization, to meet the DTI's continuing concerns over market power. Fig. 1 shows the evolution of each company's share of generation, and a forecast for 2000 if the divestitures go equally to two new companies with negligible generation assets. This restructuring would be the most favourable outcome, from the competitive viewpoint. (One of the companies is named Drax, as it will inherit the Drax 4,000MW station, the other called FFF as it will inherit Fiddler's Ferry and Ferrybridge. The outputs are based on recent average station outputs.) Fig. 2 shows the evolution of fuel shares and especially the entry of new CCGTs, half of which was built by IPPs, eating into the share of coal-fired generation.

The RECs had been privatised with the government holding a golden share in each, that could be used to block any take-over, but these shares lapsed in 1995. The subsequent take-over wave culminated in the attempted restructuring of the ESI by vertical integration between generation and distribution. In the following few months eight of the 12 RECs were targeted, and six were successfully acquired. Two were bought by their local water and sewerage companies (also regulated utilities), one by the vertically integrated Scottish Power, one by the conglomerate Hanson plc to become Eastern Group, and two by US utilities. The remaining bids, by National Power and PowerGen, were referred to the Monopolies and Mergers Commission (MMC) and then rejected by the DTI, as attempting to prematurely vertically reintegrate generation and distribution before adequate competition had been created. One of the target RECs, Midlands, was bought by another US utility group soon afterwards. Three more US utilities made successful bids in late 1996, and Electricité de France, still a state-owned company, made a successful bid to buy London Electricity from its US owner Entergy in November 1998. Powergen merged with East Midlands in August 1998, as noted above, Scottish Hydro merged with Southern Electric, the last remaining independent REC, on December 14, 1998, and National Power bid for Midland Electricity's supply business in November 1998. Two companies, NGC and Scottish Power, have made bids for US companies in 1998, reversing the earlier flow of acquisitions.[3]

3. Industrial structure and market power

The aim of restructuring was to liberalise the ESI and create a competitive market for electricity, both at the wholesale level and for final consumers. Northern Ireland has not been liberalised, and although the EU Electricity Directive will require the industry to grant large customers direct access to generators from March 1999, the mechanism had not been decided by January 1999. In Britain, however, competition was introduced at the time of privatisation. The most interesting institutional change was the creation of the Electricity Pool - a bulk electricity spot market which determines the merit order and wholesale price of electricity in Britain. This operates as a compulsory day-ahead last price auction with non-firm bidding, capacity payments for plant declared available (determined as an exponential function of the reserve margin), and firm access rights to transmission (with generators compensated if transmission constraints prevent their bids being accepted). Each day generators bid their plant into the pool before 10 am and receive their dispatch orders and a set of half-hourly prices by 5 pm for the following day. The half-hourly System Marginal Price (SMP) is the cost of generation from the most expensive generation plant accepted, based on a forecast of demand and ignoring transmission constraints. Generators declared available receive this and the capacity payments, which together make up the Pool Purchase Price, PPP. All companies buying electricity from the pool pay a pool selling price, PSP, whose difference from the PPP is the uplift, which covers a variety of other payments made to generators.

In addition to the pool, which acts both as a commodity spot market producing the reference price and a balancing market, most generators and suppliers sign bilateral financial contracts for varying periods to hedge the risk of pool price volatility. The standard contract is a Contract for Differences (CfD) which specifies a strike price (£/MWh) and volume (MWh), and is settled with reference to the pool price, so that generators are not required to produce electricity in order to meet their contractual obligations. The Electricity Forward Agreements market is a screen-traded over-the-counter market that allows contracts to be traded anonymously and portfolio positions

[3] As of January, 1999, the Government was still considering the bids by EdF and National Power.

balanced. It has not yet evolved into a futures market, partly because of the illiquidity caused by the large number of products (four-hourly periods for working and non-working days, for SMP, PPP and uplift).

Contracts are not only important for risk-sharing but were also critical in managing the transition from a vertically integrated company able to pass all its costs through to its captive customers to a competitive industry in which customers were free to buy from the cheapest supplier. The two major transitional problems facing the designers were that British coal was considerably more expensive than imported coal (and was soon to be revealed uncompetitive against gas), and that the average costs of nuclear generation, once all the decommissioning and fuel cycle costs were included, were considerably above the likely equilibrium Pool price. The second problem was dealt with by imposing a Non-fossil Fuel Obligation (NFFO) on the RECs (to buy electricity generated from non-fossil fuels, overwhelmingly nuclear power), and imposing a Fossil Fuel Levy (FFL) on all fossil generation (initially at the rate of 10.8% of the final sales price). This levy was paid to Nuclear Electric to build up a fund to meet its decommissioning liabilities (of about £9.1 billion, which can be compared with the privatisation proceeds from selling off the CEGB of just under £10 billion.

The first problem of transition was handled by a series of take-of-pay contracts between the generators and the still state-owned British Coal for the first three years at above world market prices. The generators in turn held contracts to supply the RECs for almost all their output, for up to three years, that allowed the costs of the coal contracts to be recovered from these contract sales. There was the additional and very important benefit that the profit and loss accounts of the generators and RECs could be confidently projected for the first three years, and these provided the necessary financial assurance for the privatisation to proceed.

There are two routes to effective competition in generation. The first and more satisfactory route is to ensure that capacity is divided between sufficiently many competing generators that no one generator has much influence over the price. This option was ruled out by the tight Parliamentary timetable which gave too little time to reconsider plans once it became clear that nuclear power was unsaleable. At privatisation, the two fossil generators set the pool price over 90 per cent of the time (the balance being set by Pumped Storage, which arbitraged a limited amount of electricity from the off-peak to the peak hours). Nuclear Electric, Scotland and France supplied base-load power which never set the pool price. Green and Newbery (1992) calculated that a duopoly unconstrained by entry would have significant market power and would be able to raise pool prices to very high levels.

The second and indirect route to competitive pricing is to induce generators to sell a sufficiently large fraction of their output under contract, and expose them to a credible threat of entry if the contract price (and average pool price) rises above the competitive level. A generator that has sold power on contract only receives the pool price for the uncontracted balance. If this is a small fraction of the total (and it is usually about 10-20 per cent), then there is little to gain from bidding high in the pool. High bids run the risk that the plant is not scheduled, leading to the loss of the difference between the SMP and the avoidable cost, and the trade-off between lost profit on uncontracted marginal plant and higher inframarginal profits is increasingly unattractive as contract cover increases. Contracts and entry threats are complimentary - entry threats encourage generators to sign contracts, and contracts facilitate entry.

The advantage of the creating sufficiently many companies for competition is that it does not need to rely on the continued contestability of entry, and it works well even when the competitive price is well below the entry price, in periods of excess capacity. As this route was not chosen, contracts and entry threats were all that remained, at least if price regulation was to be avoided. On vesting, the three generating companies were provided with CfDs for virtually their entire forecast output, for periods of between one and three years, and matched with comparable (take-or-pay) contracts to purchase British coal. As noted, this solved the problem of high priced coal and made the generators' income and expenditure streams predictable for the prospectuses on which they were to be sold. It also reduced their incentive to exercise spot market power to negligible levels, though not their ability to take advantage of transmission constraints and to game capacity availability. Fig. 3 shows that for the first year Pool prices were indeed low, and below the average fuel cost of the price-setting generators.[4]

When the time came to renew contracts, the generators were faced with a difficult choice. If they reduced contract cover, they would have the incentive and ability to increase their bids in the Pool, and raise the average level of prices, revenue and profits. Meanwhile, IPPs, usually with equity participation by RECs, had demonstrated a technique for making the electricity market contestable. They could sign 15-year contracts with their REC for the sale of electricity, provided the REC could demonstrate to the regulator that these contracts met the economic purchasing condition of their licence (Offer, 1992c). Given then prevailing pool prices, forecast coal and gas prices, the risk of carbon taxes and other environmental restrictions likely to raise the price of coal-fired generation, and the desirability of encouraging entry and competition, the DGES was prepared to accept that the contracts met that test. The electricity contracts in turn provided security for signing 15-year contracts for the purchase of gas. IPPs could issue debt to finance the purchase of the plant, creating a highly geared financial structure with low risk, and hence relatively low interest costs.

Such a package made the generation market contestable, as the potential entrant could lock-in future prices and hence avoid the risk of retaliatory pricing behaviour by the incumbents. This package was so attractive that within a few months contracts had been signed for some 5 GW of CCGT plant, which, in addition to the incumbents' planned 5 GW of similar plant, would displace about 25 million tonnes of coal, or nearly half the 1992 generation coal burn of 60 million tonnes. The new CCGT capacity amounted to about one-sixth of existing capacity, which was in any case more than

[4] though not below the opportunity cost of the fuel, which was on take-or-pay terms and could only have been exported at a low price or stored expensively for several years.

adequate to meet peak demand. At privatisation, about three-quarters of electricity was coal-generated, and electricity took over three-quarters of British coal output. The dash for gas and the switch from coal more than halved the size of the remaining deep coal mining industry. The coal labour force had fallen from nearly 200,000 at the time of the 1984-5 coal miners' strike to about 70,000 by 1990, but pit closures reduced numbers to 20,000 by 1993 and less than 10,000 by 1998. Fig. 2 charts the evolution of the generation fuel shares that reflect these dramatic developments.

The impending collapse of the coal market in 1992 led to a Parliamentary inquiry, which asked whether the new investment was justified on economic grounds. The eventual conclusion was that the ever-tightening sulphur limits would indeed require a shift of this magnitude to gas generation by the end of the century, but that about half of the new capacity could usefully have been delayed several years. During the inquiry the industry was put under considerable pressure to sign 5-year coal contracts, again at above world prices. The RECs signed 5-year coal-backed contracts with the generators and were allowed to pass through the extra costs to the captive domestic customers. The new coal contracts made it possible for the Government to privatise the coal industry for an acceptable price.

Entry demonstrated that the market was contestable and produced a more competitive outcome that might have been expected from the duopoly. The DGES was required to encourage competition and had few means available other than encouraging entry. This, together with favourably priced deals that the entrants signed with their REC partners that could be passed through to domestic customers helped encourage excess entry. The duopolists may have believed that entry was therefore inevitable and that they had little to lose by keeping prices high. The DGES noted the growing discrepancy between rising Pool prices and falling fuel costs since vesting, and specifically the sharp increase in Pool prices in April 1993, as the previous year's contracts were replaced on 1st April (Offer, 1994a and fig. 3). He concluded that their market power had enabled them to raise Pool prices above competitive levels. Faced with the alternative of a reference to the MMC, the generators agreed to a price-cap on Pool prices for the two financial years 1994-5 and 1995-6. They also agreed to divest 6 GW of plant, selling it all to Eastern Group as noted above. This failed to introduce as much competition as hoped, as the two generators transferred the plant for a fixed sum plus £6/MWh generated (nominally to cover the opportunity cost of the sulphur allowances transferred with the plant). This payment per unit generated encouraged Eastern to bid the plant exactly as before, and if anything National Power and PowerGen raised their prices in winter of 1997-98, sacrificing market share to Eastern and other generators in a successful attempt to keep Pool prices up while fuel costs continued to fall (Offer, 1998f).

By 1997/98 over 14 GW out of 62 GW total capacity was CCGT (23%), and this was forecast to rise to 17 GW in 1998/99 (27%) and 23.5 GW by 1999/2000 (33%) (NGC, 1998). This second dash for gas coincided with the ending of the coal contracts signed in 1993, which were timed to expire at the end of the domestic franchise, and matured at the end of March 1998. Again, coal demand was threatened, but this time the

Labour Party was in power, a traditional supporter of coal miners. Their immediate response was to prohibit any further gas-fired generation until the issue of coal was resolved in the now traditional inquiry. Critics of the ESI argued that the market was biassed against coal, and Offer recommended reforming electricity trading arrangements, and abolishing the Pool (Offer, 1998f). The Parliament Trade and Industry Committee argued that overzealous sulphur emissions restrictions by the Environment Agency was at least partly to blame (House of Commons, 1998a), while the DTI concluded that the coal-fired plant that set the pool price were bid uncompetitively, and that more competition was therefore required. The eventual outcome is still emerging but PowerGen has agreed to sell a further 4 GW and National Power is also likely to sell 4 GW, in exchange for being allowed to vertically integrate into distribution and/or supply. This brings us up to the present and its current problems that are discussed in the last section.

4. Performance

Competition may not have been sufficient to keep prices at competitive levels or to avoid the need for continuing regulatory concern, but it was certainly sufficient to dramatically improve performance. In the five years after 1990:

- labour productivity in the former CEGB doubled
- nuclear output increased 28% overall with no increase in capacity, and nearly 50% from the more modern AGRs
- gas-fired generation rose from almost nothing to 15% of output, and to 30% in 1997
- new entrants accounted for over half of new capacity
- fossil fuel cost/kWh fell 45% in real terms
- nuclear fuel cost/kWh fell 60% in real terms
- coal prices fell 20% in real terms
- CO_2/kWh fell 28%, and SO_2 and NO_x fell by over 40%

The claim that competition rather than privatisation improved performance requires some defence. First, the productivity gains were shared by all three generating companies, even though Nuclear Electric remained state owned until 1996. Every power station has to bid into the Electricity Pool each day, and the resulting revenue provides a daily measure of performance which concentrates the minds of station operators wonderfully. The demonstrated threat of entry by IPPs meant each station had to compete against the cost of combined cycle gas generation to survive, and this entry price has continued to fall with improvements in technology and declining gas prices - both the result of competition in those two markets. Individual large coal-fireed power stations have also doubled labour productivity to remain competitive.

Second, the wires businesses of the RECs retained their franchise monopoly, and did not experience any appreciable change in efficiency growth until the Government's golden share expired and they could be taken over on the stock exchange. Competition in the capital market then squeezed out considerable productivity improvements. Third, competition in supply was originally intended for large customers, but relatively late in 1989 it was proposed to extend it to all consumers by 1998. Customer choice is critical in forcing the generators to adopt least cost fuel choices. A franchise monopoly gives the Government the means to influence fuel choices because the generators can be bought off in return for passing the extra cost through to the captive consumers. Initially only about 30% of total supply was competitive but the 1994 extension increased the competitive share to about a half, and by March 1999 it will be completely open. The fact that half the market could choose their supplier forced the generators to halve their original coal contracts. However, the continuing domestic franchise allowed the remaining coal to be sold at above world prices and kept domestic prices 9% higher than they will be when these contracts end. It is hard to believe that any REC will sign an uncompetitive contract in future once they have to compete for customers.

Finally, nuclear power was tested by the market and found wanting. Margaret Thatcher as Prime Minister was one of the principle architects of privatisation. She was particularly keen to find a way of countervailing against the power of the coal miners. In 1974 a coal miners' strike had brought down the Conservative Government and returned a Labour Government to power. In 1984 the coal miners went on strike again, this time for nearly a year, with the stated aim of bringing down the Thatcher Government. Not surprisingly, Margaret Thatcher was very keen on the planned nuclear power station programme. The first of what was originally intended to be 10 PWRs was already under construction, and the whole privatisation was structured to make nuclear power viable. The non-fossil fuel obligation forced RECs to buy nuclear power, and the fossil fuel levy transferred to Nuclear Electric allowed it to make a surplus over operating costs to accumulate a fund to pay for decommissioning liabilities. Nuclear Electric continued to argue that although the first station was uneconomically expensive, future PWRs would be cheaper and justified by their additional contribution to fuel diversity, reduced green house gas emission, and promoting export sales of the technology. The market signalled otherwise, and when the modern nuclear stations were privatised in 1996, Nuclear Electric abandoned any intention of building more nuclear plant.

The market thus replaced policy makers in determining the fuel mix, and allowed us to stop the expensive British coal and nuclear options. Competition forced down costs, but was not sufficiently intense to lower prices to the same extent. Nevertheless, Newbery and Pollitt (1997) estimated the costs and benefits of restructuring and privatising the CEGB, and found that even if there were to be no further improvements, and ignoring the considerable environmental benefits, the gains achieved and projected up to 1996 were equivalent to a permanent cost reduction of about 5% of generation costs. Fig. 4 shows the evolution of costs and profits in the successor companies to the CEGB. In present value terms that is equivalent to about 40% on the current cost value of the assets concerned, and about 100% on the privatisation sales price. Environmental benefits might double this figure.

They also tried to estimate who gained and who lost, though this involved more crystal ball gazing. Their best estimate was that the Government (that is, the taxpayers) lost about £4 billion in present value terms, discounting lost revenues at 6% to 1996, after allowing for the sales receipts of about £10 billion. Consumers lost between £1 billion and £6 billion (also in present discounted value), depending how rapidly future prices fall back to their trend level. Shareholders gained a profit stream worth about £24 billion discounting at 6%, for a share purchase cost of £10 billion. In short, the overall cost reductions were not huge - at 5% for ever - but then the industry was moderately well operated before privatisation. All the gains were reaped by shareholders, and the reason is that the price of electricity did not fall anything like as much as the cost of fuel or the reduction in other non-fuel costs, which also fell significantly. Fig. 5 shows the evolution of prices for different categories of consumers, and also the unit fuel cost, over a long enough period of time to detect trend productivity improvements. It shows the margins between fuel costs and prices widening after privatisation, partly because the fossil fuel levy (FFL) was introduced, but mainly, as fig. 4 shows, because of the increased profit margin. (The prices net of FFL are shown for domestic consumers, extra large consumers and the industrial average, and from an initial value of nearly 11%, they have recently fallen to less than 2% as the nuclear levy has been ended and the fundsd are devoted solely to renewables.)

Pollitt (1997, 1998) applied the same cost-benefit methodology to measuring the benefits of restructuring and privatising the ESI in Scotland and Northern Ireland. The results throw an interesting light on the relationship between the structure chosen at privatisation and the extent of gains and consumer benefits. Scotland was privatised with little restructuring as two vertically integrated private regulated utilities, and a state-owned nuclear company that was sold as part of British Energy in 1996. The two electricity companies, Scottish Power and Scottish Hydro-electric, are viewed as national champions and protected against take-over by permanent golden shares, though this has not stopped them buying up other utilities in England and Wales. They are viewed with pride as very successful companies, but the detailed cost-benefit evidence provides a less flattering assessment.

Pollitt argues that restructuring and privatisation (R&P) had beneficial effects on the nuclear industry, by advancing the closure of the loss-making old Hunterston A station and extending the life of the profitable Hunterston B. The interconnector to the south was strengthened with beneficial effects, and altogether the investment effects were comparable to those in England and Wales, at about one-third turnover.[5] The

[5] Turnover was used by Galal et al (1994) as the scaling factor, though it makes the ratios of present discounted gains to annual turnovers tend to be rather large. At 6% discount rate, the ratio of the present discounted benefits to turnover can be multiplied by 0.06 to give a comparison of annualized gains to annual turnover. The turnover of the ESI (including distribution) of England and Wales was £16 billion, while that of Scotland was £1.9 billion and of NIE was about £0.5 billion. There is an obvious problem in making comparisons across the three cases as Scotland and NIE are vertically integrated, while the case study of the CEGB excludes the RECs. The approach taken is to relate the CEGB to total ESI turnover

environmental effects were small but negative, deriving from the early closure of Hunterston A and the increased interconnector capacity displacing CCGT output in England. The present value of the efficiency gains under the pro-privatisation counterfactual were small (10% of turnover in Scotland compared to over 50% in England and Wales), but cancelled by the restructuring costs, which were also small (as little restructuring actually occurred). The total efficiency gain was about zero in the more favourable (pro-orivatisation) counterfactual.

The distributional effects were somewhat worse than for the CEGB - consumers lost £1.5 billion (80% of turnover, compared to 8% in England and Wales), the Government sold the assets for £3.6 billion but suffered a fall in discounted receipts of £5.2 billion (excluding the subsequent windfall tax), while the owners received a profit stream worth £6.7 billion for their payment of £3.6 billion.

Northern Ireland is smaller, but has adopted a structure which appears to offer greater incentives for efficiency, though less ability to transfer the benefits to consumers. The generating stations were placed in three companies and sold in a trade sale with long-term power purchase agreements with the franchise transmission and distribution company, NIE, as explained above. The generating stations have considerably improved performance and cut costs, but the power purchase agreements prevented these gains from being transferred to consumers. The investment (fuel switching) effects of the restructuring appear modest (10% of turnover, compared to 34% in Scotland). The environmental effects were negligible, while the restructuring costs were high (£118 million, 24% of turnover) and were criticised by the Public Accounts Committee. The efficiency savings were, however, very large at £930 million, 186% of turnover (compared to 55% for the CEGB).

The net efficiency gains (excluding the negligible environmental benefits) discounting at 6% were £548 million on a sales value of £909 million, a return of 60% compared to the equivalent return of 99% for just the CEGB alone (which is flattering, as it ignores the value of the RECs). These efficiency gains were, as in the other cases, very unequally distributed, with consumers losing £432 million (86% of turnover, much as in Scotland), the Government realising a sales value of £909 million but foregoing future revenue streams worth £247 million, while owners gained a profit stream worth £1,227 at 6% for their outlay of £909 million.

5. Regulation

The British ESI was privatised under the *Electricity Act 1989* which specifies the general framework for regulation, and the requirement that utilities supplying services specified in the Act will need a licence. Thus there were generation licences for the two non-nuclear privatised generating companies National Power and PowerGen, a somewhat different licence for the state-owned Nuclear Electric (specifying such issues as safety),

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and ignore any REC improvements, which understates its performance.

individual licences for IPPs, a transmission licence for NGC, Public Electricity Supply (PES) licences for the RECs (which combined both distribution and supply in the authorised area), and Private Electricity Supply or 'second tier' licences for others supplying consumers within a PES's authorised area. There is a proposal to create new licences which distinguish between distribution and supply, so that RECs can choose whether to also hold a supply licence, and generators would then be able to purchase the supply business from a REC (as National Power wished to do in late 1998).

The Act requires the Secretary of State (the elected minister holding the portfolio of the Department of Trade and Industry) to appoint the Director General of Electricity Supply, the DGES, to carry out functions assigned to him by the Act, and he holds office for periods of five years. They each have a duty to exercise the functions assigned or transferred which are specified in Section 1(3) of the Act and either the Secretary of State after consulting with the Director or the Director with the consent of the Secretary of State may grant a licence to generate, transmit or supply electricity. It is the prime duty of the Secretary of State and the Office of Fair Trading to review proposed structural changes to the industry, but it is the responsibility of the DGES to examine the current operations of the industry. The Act set up the Office of Electricity Regulation as a non-ministerial Government Department, whose budget is approved by Parliament, and which is staffed by civil servants, many of whom are on secondment from the DTI. The DGES presents his annual report to the Minister, but cannot be sacked (except for gross misconduct) before the end of each term of appointment. Offer exhibits considerable independence within the constraints laid down by the Act, and the first DGES has certainly been prepared to criticise aspects of Government policy such as the moratorium on the building of new CCGTs imposed in 1998.

The bulk of the regulatory system is contained in the licences, which are drawn up to suit the specific circumstances of the licencee with the agreement of the Secretary of State or the DGES, and the most important regulations are contained in the PES and transmission licences which cover the natural monopoly parts of the unbundled industry created on privatisation. Both licences contain conditions that control the average level of prices, require non-discrimination and prohibit cross-subsidy, and specify the conditions to be met to ensure security of supply. The PES licence requires the licensee to acquire electricity from the most economic sources and restricts the extent of own generation to preclude vertical re-integration. The transmission licence requires NGC to schedule power stations in order of lowest bids and to run a settlement system. In addition, the generators, NGC, NGC Settlements Ltd, and Energy Pool Funds Administration Ltd must sign a Pooling and Settlement Agreement which contains the contractual obligations under which bulk electricity is dispatched and paid for.

Unless revoked, the licences continue until the Secretary of State gives 25 years notice, which he may not do for at least 10 years, ensuring that the initial licence is for at least 35 years. The conditions of the licence may be modified or amended by agreement between the licensee and the DGES, or following a reference to the MMC as provided for in the *Electricity Act* (sections 14 and 15). An example of an agreed modification is provided by the insertion of a new condition 9a in the generation licences of National Power, PowerGen and Nuclear Electric, authorised on 24 July 1992, which enables the Director to receive information that allows him to monitor whether the generators 'are restricting, distorting or preventing competition in the generation or supply of electricity'. This was agreed after PowerGen had manipulated the pool price by declaring generation capacity unavailable causing capacity payments to reach very high levels, a manipulation that was compounded by redeclaring the generation stations available and thus eligible for these capacity payments (now no longer really needed) on the day of dispatch.

Regulating distribution

The twelve RECs have a relatively simple form of price-cap regulation, reviewed every five years. The initial price-cap was not very onerous, and the RECs made considerable profits. The first review, which began in 1994, proposed tighter limits, but these were widely felt to be still too generous. A subsequent attempt by Trafalgar House (a conglomerate) to take over one of the RECs caused share prices to reach such heights that the DGES decided to re-open the distribution price review (Offer, 1995), with a subsequent dramatic collapse of share prices common not only to the RECs but also of the generators, at an embarrassing moment during the sale of the second tranche of the two original generators by the government.

The RECs were then widely perceived by the public to be fat, lazy monopolies whose chairman enjoy unreasonably inflated salaries, selling electricity whose domestic price had not fallen in real terms despite dramatic decreases in the price of fuel. This, and high profits in other utilities, lead the Labour Party in opposition to promise to impose a windfall profits tax on utilities, which was duly implemented when they were elected in 1997. Productivity certainly appeared to improve after the first review, and aggregate net operating costs (excluding depreciation, NGC exit charges and property taxes, i.e. controllable expenditure) fell 28% in real terms between 1994/95 and 1997/98 (or 10 per cent per year) to £1350 million per year (Offer, 1998g). Unfortunately, non-operational expenditure more than doubled (from £170 million per year to £400 million per year) in response to the requirement to introduce competition into domestic supply. The next periodic review will be for the period 2000/01 to 2004/05, and the RECs are forecasting that controllable operating costs will only fall 4 per cent in total over this period, while non-load related capital expenditures will be nearly twice the level of the first price review. The process of setting the next set of price-caps has, however, only just begun and the forecasts may merely be the opening positions in a lengthy process.

Regulating transmission

The RECs initially jointly owned NGC, whose implied sales price was £2.5 billion at March 1996 prices, but which was floated for £4.5 billion (which includes non-regulated assets like Energis into which NGC had invested £400 million).[6] Offer accepted the market value and deducted an estimated market value for Energis of £250 million leaving a regulatory asset value of £4.15 billion. Clearly it was hard for the market to properly value NGC in 1990 without some evidence of its revenue flows, and there would have been a good case for delaying privatisation (as with the nuclear power stations) until the market was ready (presumably in December 1995). The first transmission price control review after flotation came into effect on 1 April 1997 and cut allowed revenues by 20 per cent, followed by a price cap of RPI-4% (Offer, 1996).

NGC's charges for transmission are quite simple. Generators pay an annual connection charge which varies (considerably) by zone based on declared net capacity or, where the charges are negative, on system peak generation. Consumers pay an annual charge which also varies by zone based on their demand in the three half-hours separated by 10 days of system maximum demand. Generators receive and consumers pay the same price per MWh regardless of location as transmission losses are smeared over all consumers equally. The total revenue from transmission charges are regulated but the zonal pattern of charges is subject to agreement with the DGES. On privatisation, this zonal pattern was known to be unsatisfactory and was subsequently reviewed and revised (NGC, 1992). The present structure is based on the incremental capital cost of providing additional capacity on existing routes, and the costs of providing the additional spare capacity for systems security are then split between consumers and generators (somewhat arbitrarily, but as it is the total transmission cost that is added to the generation price to derive the delivered price the allocation up or downstream is irrelevant).

Ancillary services to ensure system stability and security are secured by NGC Ancillary Services, increasingly using incentivised and market-based mechanisms. One of the least satisfactory parts of the institutional structure of the English ESI is the Pooling and Settlement Agreement (PSA). This specifies the contractual agreement signed by generators and suppliers which provides the wholesale market mechanism for trading electricity. It defines the rules, and requires almost all parties wishing to trade electricity in England and Wales to do so using the Pool's mechanisms. It provides the supporting financial settlement processes to compute bills and ensure payment, but does not act as a market maker. Physical constraints on transmission, speed of response of generation, frequency stability and the over-riding requirement of security and continuity of supply in a decentralised and notionally unregulated market require complex incentives, payments and obligations which inevitably offer opportunities for sophisticated market manipulation. Because the PSA is a legal contract between a large number of signatories many of whom have opposing interests it is extremely hard to reach agreement to change,

[6] The RECs' shares were sold for £5182 m, which rose to £6264 m by the end of the first day. Uprating the equity by 1.15 gives £7204 m. £2815 m of bonds were sold at the same time, and cash balances were £1,000 m, giving an implied sales price of £6997 m, or 46% of the net asset value of £15347 m. The CCA value of NGC was £4.7 billion (£4896 million *less* the value of Pumped Storage Business of £196 million) so the implied sales value was £2.14 billion. See Newbery (1996).

making the system under which the Pool operates inflexible and unresponsive either to members' or regulatory criticism. The Pool Review, ordered by the Government in late 1997, was intended to address such criticisms and propose reforms and is discussed below.

The Scottish Transmission price controls were reset to run from 1 April 1994 for 5 years with a revenue cap based on a forecast number of units transmitted subject to RPI-1% for Scottish Power and RPI-1.5% for Scottish Hydro-Electric, with a first year price cap of RPI-2.5%. These X factors were lower than those for NGC reflecting lower transmission operating costs per MWH transmitted and hence less scope for productivity improvements (Offer, 1993). Northern Ireland had an integrated transmission and distribution business that was initially subject to a price-cap of RPI+3.5% for the fixed element (75% of the total) and RPI+1% per MWh transmitted. This was reset from 1 April 1997 with a step change downward of 31% followed by RPI-2% over the next four years. The decision was appealed by NIE to the MMC, who proposed a compromise of a price cut of 25%, followed by the same RPI-2% for the next four years. The regulator decided not to accept the MMC finding so NIE took the regulator to judicial review, and won its case in the Court of Appeal in late 1998 (Green, 1999). The Government has been considering the relationship between the dispute resolution procedure of the MMC and the powers of the regulators in its consultation on the reform of utility regulation (DTI, 1998a), and has proposed that regulators should seek the endorsement of the MMC on any modifications to the MMC's findings (DTI, 1998c, p31).

6. Current issues and debates

The Electricity Pool has received constant criticism by the media, from the regulatory body, Offer, and from the House of Commons Trade and Industry Committee since its launch in 1990 (e.g. in House of Commons, 1992; Offer 1992a,b,c; 1994a,b). In May 1997 a Labour Government was elected, replacing the Conservative Government that had privatised the ESI. In October 1997, the Government asked the DGES to review electricity trading arrangements. The Pool Review Steering Group agreed as the overall objective 'that trading arrangements should deliver the lowest possible sustainable prices to all customers, for a supply that is reliable in both the short and long run' (Electricity Pool, 1998).

The main criticisms were about market manipulation, market design (including criticisms about capacity payments, constraint payments and transmission charges), and the governance structure. Reforming (or replacing) the present governance structure was clearly critical as the Pooling and Settlement Agreement had impeded reforms in the past. The most serious criticism of the performance of the electricity market was that of the continuing market power of National Power and Powergen, despite divesting 6 GW capacity and substantial entry by IPPs. The *Pool Review* accepted this concern, but decided that 'it would not be sensible to overload the very full agenda' by addressing market power issues (Offer, 1998e, p114).

The *Pool Review* instead concentrated on market design issues, where the main criticisms were that it was only half a market with inadequate representation of the demand side, that it was opaque, unpredictable, and therefore hard to hedge using standard contracts, and that it was compulsory which prevented trading outside the Pool and hence discouraged contracting. Paying all generators the same marginal price further discouraged contracting and aggressive bidding, and the SMP was only loosely related to (and typically considerably higher than) the marginal energy price used to determine the merit order. In addition, capacity payments were volatile, unpredictable, and excessive.

The *Pool Review* argued that the complexities of price formation in the Pool gave the generators more market power than a normal commodity market. It recommended that the Pooling and Settlement Agreement should be replaced by a Balancing and Settlement Code. The Pool as such would end and be replaced by four voluntary, overlapping and interdependent markets operating over different time scales - bilateral contracts markets for the medium and long run, forward and futures markets operating up to several years ahead, a short-term bilateral market, operating from at least 24 hours to about 4 hours before a trading period, and finally, a balancing market from about 4 hours before real time. The System Operator would trade in this market to keep the system stable, and use the resulting prices for clearing imbalances between traders' contracted and actual positions. This structure mirrors that emerging in the British gas market, and has similarities with electricity markets in Scandinavia, Australia and the United States.

At present, the pool operates as a balancing market, as about 90% of electricity is traded on contracts. The argument for replacing the method of determining the pool price from a complex bid involving start-up, no-load and marginal energy prices by a simple bid to make the market more transparent is, however, suspect. The simple bids would still have to combine fixed costs, start-up costs, and views about the likelihood of incurring flexibility costs, and will be harder to examine for the exercise of market power. The argument that Pool prices are hard to predict and therefore hard to hedge, while true, is not counterbalanced by evidence that a rather thin balancing market would be more predictable and more easy to hedge. Indeed, one of the main arguments made for the change is that the balancing market is intended to remove the Pool's role as a reliable market of last resort, and thus to encourage contracting and the securing of balancing services well before the balancing market opens.

Part of the case for the new structure is that flexibility (provided by coal-fired plant) is under-rewarded, biassing the market against coal. At present, coal-fired generators can provide the required amount of flexibility needed for system stability at very low marginal cost in adequate amounts so its value at the margin is low. At present individual failures to balance are automatically dealt with by aggregating, where many imbalances automatically cancell. Forcing each contractor to ensure individual balance raises risk and artificially raises the value by balancing services, thereby prejudicing the benefits of an integrated system. If the balancing market is so designed to favour flexible plant, it is more likely to encourage excess flexibility and to favour those generators who possess low-cost flexibility, namely those who are already credited with having excessive market power.

The proposal to end the Pool which mechanically produces a transparent price and replace it by bilateral markets has been warmly welcomed by traders, who are understandable enthusiastic about the proliferation of complex and largely opaque markets in which they can make their margin. The DTI reported that the major coal-fired generators supported the reforms, but that IPPs were sceptical about the proposals and argued that the existing Pool would work well if the problem of market power were resolved. (DTI 1998b, §6.7-8). One should worry if those with market power welcome the reforms and potential entrants and small competitive plant are concerned that it will disadvantage them. It suggests that the new trading arrangements allow the continued exercise of market power, and that entry by new competitors may be made more difficult.

The main argument provided by those defending the new trading arrangements is that they will lower electricity prices, though there is no guarantee that they will lower costs (and some evidence that costs may rise). Offer estimated the restructuring costs at £500 million over 5 years or about 1.25% of PPP, while transactions costs look set to rise. Offer also argued that the restructuring costs would be more than covered by a fall in (final) prices of 1%, but from a resource point of view a fall in prices is not the same as a fall in costs Indeed, as noted above, Newbery and Pollitt (1997) argued that the restructuring of the CEGB had been socially beneficial because it lowered costs by 5%, even though it raised prices relative to the counterfactual

The reason why prices are expected to fall is that participants can no longer rely on buying or selling in the Pool and will be forced to contract. As some 90% of electricity is already traded under contracts, any change will be modest at best. The claim is that on the one hand contract price discovery will be encouraged once the pool price ceases to be a good guide to trading terms, while on the other hand the lack of a clear reference pool price will encourage harder bargaining over the terms of these contracts, and they will be driven closer to cost. These two claims cannot easily be reconciled. If plant owners know the likely contract price, why would they accept less? This seems little different from the present situation in which plant owners cannot predict the future pool price with any confidence (as convincingly demonstrated in the reports) when they agree on what terms to contract.

Removing the only transparent market is likely to raise contracting costs, and so any benefits could only come from the argument that sequential contracts markets would reduce market power compared to the present system. While it is true that contracts reduce the incentive to manipulate the balancing market or Pool as most revenue will already have been secured in the contracts, the real issue that is not addressed is what, given present allocations of plant, will determine these contract prices. The argument made above is that if generators have market power then prices will be set by the conditions of entry, and will continue to be so set until more competition is introduced into the price setting part of the market. This claim continues to hold under the new trading arrangements as under the old.

At a deeper level the argument that prices will fall seems to be that removing the option of being guaranteed sale at pool prices alters the outside option in the bargaining game between the generator and supplier, forcing down the bargained price. But buyers also lose this option, and it is not clear that the balance of power will shift in their favour. Furthermore, Offer's review recognises that the Pool reduces the entry risk for new entrants by providing them with the option of selling at Pool prices. If the returns for entrants are made riskier and less attractive, the obvious conclusion is that there will be less entry, and that the threat of entry will exercise less downward pressure on prices.

The new markets seem designed to create more risk about the wholesale price. Wholesale price risk in an unbundled structure translates directly into profit risk: a high price shifts profits to generators away from the supply business, while a low price benefits supply at the expense of generators. The risk can be avoided or cancelled by vertical mergers in which generators are assured of a semi-captive market. This will also reduce the transactions costs of contracting, and reduce the risk of failing to find a buyer and hence being forced into a distress sale in the short-term bilateral or balancing market. The rush to vertically merge is already evident from the deals currently being struck. The larger the share of the market covered by vertically integrated companies, the harder entry will be and the more disadvantaged will be those companies who remain unintegrated. A re-integrated industry will look more like the German electricity cartels than the competitive industry which was once the objective of the English experiment. Such a structure and the lack of a transparent Pool will discourage entry by further gas-fired generators, which appeals to the coal industry, though whether it is good for *British* coal is another story.

The Government has stressed the importance of creating more competition and has been willing to accept mergers and vertical integration as a price worth paying to achieve this. The irony is that if generation is made adequately competitive, then a transparent pool would almost certainly deliver lower prices and lower cost than the proposed new trading arrangements, whose sole (and doubtful) defence is that they might reduce market power and lower prices in an otherwise unrestructured industry. Competition makes the reforms unnecessary, and merely requires changes to the governance structure of the pool to allow the various modifications which would improve its operation and which have so far been hampered by the Pooling and Settlement Agreement.

7. Liberalising the franchise market - costs and benefits

In the first year that the 1 MW market was opened to competition, the RECs lost two-fifths of their sales volumes, and their market shares have continued to decline, so that by 1996/7, Offer estimated that the RECs supplied less than 30% of this demand in their local market, with generators and other RECs competing to supply these customers. The size of the competitive market increased in April 1994, when the 50,000 sites with demands of between 100 kW and 1 MW were allowed to change their supplier. One quarter of them did so in the first year, and half had done so by the following year. Prices fell, mostly because the non-franchise market was able to escape the coal contracts whose costs now fell on the remaining captive franchise customers.

One of the main benefits of supply competition is that it makes it harder to sustain uncompetitive but politically attractive interventions to support favoured fuels like domestic coal. Of course, a determined government can still impose uncompetitive fuels on the industry. The Non-fossil Fuel Obligation and the Fossil Fuel Levy used to subsidise nuclear power provide an immediate example, but at least they were passed in legislation after democratic debate, and were imposed using taxes and transfers. The FFL and NFFO survive as mechanisms to subsidise renewable energy, where the revenue collected makes up the short-fall between the contract price of the renewables bid in a periodic auction, and the pool price. The distortions caused by this system of support are minor, as they do not affect bidding in the Pool, and are confined to the demand side of the market, raising prices by rather less than 2%.

The plan was to allow the remaining 23 million consumers (with half the total demand) to choose their supplier starting in September 1998, making it difficult for RECs to pass on any uncompetitive contracts (with coal producers, or with equity-participating ‘independent’ power producers). It has, however, proven very difficult to design a cheap and simple form of domestic retail competition, and the costs of setting up the new system and operating it for the first 5 years are estimated at £726 million (House of Commons, 1998b). There are no new meters, and the costs arise from the very complex system of estimating and re-estimating the billing costs to charge to each supplier and the new IT systems needed to keep track of a changing portfolio of customers. The potential efficiency gains are small as the supply business’s own costs are only about £600 million per year, unless investment efficiency in generation and transmission improves as a result. Of course, the potential benefit of removing the ability to tax consumers for inefficient regulatory choices is much larger, but this could surely have been achieved at lower cost.

The effect of ending the franchise on consumers is rather hard to predict. The RECs signed contracts with IPPs that could be passed on to these customers at above subsequent Pool prices. In 1996/7 the RECs purchased 71.7 TWh of electricity under the 1993 coal contracts (discussed above) at 3.92p/kWh and 28.9 TWh from IPPs at 3.84p/kWh, when the time-weighted Pool Selling Price (PSP) was 2.572p/kWh and the demand-weighted price was 2.793p/kWh (Offer, 1997). If the IPP contracts were essentially base-load contracts for which the time-weighted PSP is the relevant comparison, then they cost nearly 50% more than buying in the Pool. Offer (1997) suggests that the IPP contracts are more like contracts bought for the non-franchise market (which will be less peaky than overall demand, but more peaky than a base-load contract), which were 2.93p/kWh, making the IPP contracts 31% more expensive than these contracts.

Customers who switch will presumably avoid these stranded contracts, and to protect those that remain with their incumbent supplier, the regulator has capped prices sold by RECs to their incumbent domestic customers and this regulated ceiling will fall by about 9%, reflecting the end of the over-priced franchise contracts discussed above. These caps are set rather high, and RECs are offering reductions of up to 10% outside their area.[7] Industry analysts were expecting a rapid concentration in the supply business as companies merge or exit.

In early 1999 it was still too soon to say how domestic competition would work in electricity. We can look at evidence from the domestic gas market, which was gradually opened up from April 1996. Until then, British gas was vertically integrated and signed long-term contracts for beach deliveries of gas, which it transported and sold to its 18 million customers. The gas industry has been gradually unbundled, a spot market has emerged, and the spot price of gas is about half the old contract price. New gas is therefore cheaper and new suppliers can offer considerable discounts on the British Gas price, effectively stranding the old contracts. About 25% of customers switched in response to a price reduction which was about £60 per year or 20% of the annual gas bill. British Gas has responded to competition as it lost market share, partly by promising a better deal for the combined supply of electricity and gas.

Green and McDaniel (1998) model the effects of competition, assuming that 25% of customers might switch in response to a 20% reduction in price. They suggest that customers who switch will do rather better than those that do not, and larger customers will do better than smaller customers. Overall, the ending of the franchise contracts benefits the franchise market by £285 million per year, but this is outweighed by losses upstream (and in levy revenue), so that the economy loses £130 million per year. Green and McDaniel argue that yardstick competition would have achieved comparable gains to consumers, more equitably distributed and at lower cost, with a net gain to the economy overall of £142 million per year.

By 2000 the regulator will need to decide whether to deregulate supply completely. If about one-half to two thirds of customers are reluctant to switch, then incumbent RECs and Centrica (British Gas) may be left with a comfortable quasi-monopoly position, much as the high street banks have in Britain. Pressures to cut costs (which yardstick competition might have encouraged) may then be less intense and the comparison even less favourable to ending the franchise. Against that, continuing the franchise market might have encouraged the Government to collude with the industry in visiting the costs of any energy or industrial policies onto the domestic market, so the cost of competition may be the price to pay for freedom from such interventions.

8. Conclusions

As with most political decisions, the reasons behind the restructuring of the electricity industry were many and varied. Excess capacity and sluggish growth were common to most developed countries, and reduced the importance of ensuring secure sources of investment funding that state ownership and vertically integrated franchise monopolies could guarantee. The mismanagement of post oil-shock investments was coupled in

[7] Green (1998) tabulates the offers by several RECs in others' areas for a 3300kWh customer, and shows that in most cases the incumbent REC charges the highest price in its own region and undercuts incumbents in other regions.

Britain with an over-dependence on high cost coal that was controlled by a hostile miners' union that had already caused the fall of one previous Conservative Government and had only been defeated in its attempt to unseat the Thatcher Government by a narrow margin. Privatisation had been politically popular in altering the balance of power between labour and capital, and had delivered impressive productivity improvements. The new price-cap system of regulating network utilities had been designed for efficiency and successfully implemented. Privatising electricity would have a sizeable impact on the national debt and the short run public sector borrowing requirement, as well as advancing support for popular capitalism by wider share ownership. Finally, while privatising BT and British Gas had been relatively simple as they were not restructured, the idea of transferring public monopolies to private ownership had been so strongly criticised that liberalisation was essential. Fortunately, the Government failed to appreciate just how hard unbundling the industry would be before it made the political commitment to restructuring and privatisation. The final result, if far from perfect, was a great improvement on what went before, and was a remarkable achievement that demonstrated what was possible to the rest of the world, and certainly encouraged the passage of the EU Electricity Directive.

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