Competition and efficiency issues in electricity supply in England and Wales

by

Brian Tilley

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Abstract

The thesis examines competition and efficiency in the liberalised electricity industry of England and Wales after 1990 Literature review and economic analysis is undertaken for four activities generation and trading arrangements, transmission pricing, comparative efficiency in distribution, and competition and access in supply. In trading arrangements and distribution, the analysis is supplemented by empirical work using both event study models and non-parametric efficiency analysis. Broad conclusions are that there is some evidence of generators behaving strategically in the Pool, and productivity is variable among the distribution companies, with the increase attributable to the industry as a whole.

A reform of transmission pricing is advocated based on the de-centralised principles of Coasian property right, to remove the current pricing distortions Trading arrangements have been evaluated, concluding that competition in generation through divestment of price setting and infra-marginal plant will deliver lower spot prices, without the need to spend £1bn in switching to a new system which has not had a proper cost-benefit analysis. The use of load profiles in domestic retail supply has facilitated competition, but has acted as a barrier to new tariff structures

Keywords competition, efficiency, electricity, liberalisation, pricing, regulation

Contents

Chapter 1 Introduction

The electricity industry has changed beyond recognition over the last nine years, since privatisation The objective of this thesis is to analyse the constituents that make up the industry, and to assess the implications of current policy. In the 1980s, the British government adopted market-orientated thinking to many sectors of the economy. The utility industries were at the heart of this fundamental shake up of the economy Low levels of productivity and efficiency and high costs were seen as an anathema to the government, and had to be tackled in a new way. Government ownership was seen as one of the fundamental problems with these industries. Electricity as with other utilities such as gas and telecommunications was privatised. This necessitated economic regulation since at least part of the electricity industry was deemed to exhibit natural monopolistic characteristics.

Regulatory reform began in Britain, and many of the results from the British experience have been adopted in other countries Chapter two therefore considers traditional forms of regulation, largely adopted from the United States of America This is then critically compared with incentive-based regulation which form the basic regulatory programme in Britain today. Two forms of incentive-based regulation are considered; price cap and sliding scale regulation Both of these topics are analysed, because in recent years there has been a debate over the effectiveness of price cap regulation, and whether alternatives could be in place which better serve the customer

Electricity as a product was thought of as simply a single service, which was paid for at the point of delivery using a single tariff Joskow and Schmalensee (1983) showed theoretically that it is both possible and desirable to move away from a command-based system to a contractual-based system. Prior to 1990, the electricity industry was a vertically integrated monopoly. The Central Electricity Generating Board (CEGB) supplied bulk power to the twelve area boards in England and Wales The CEGB consisted of generation power stations and the transmission grid The area boards were made up of distribution and supply Figure 1.1 outlines the pre-1990 structure of the electricity industry.

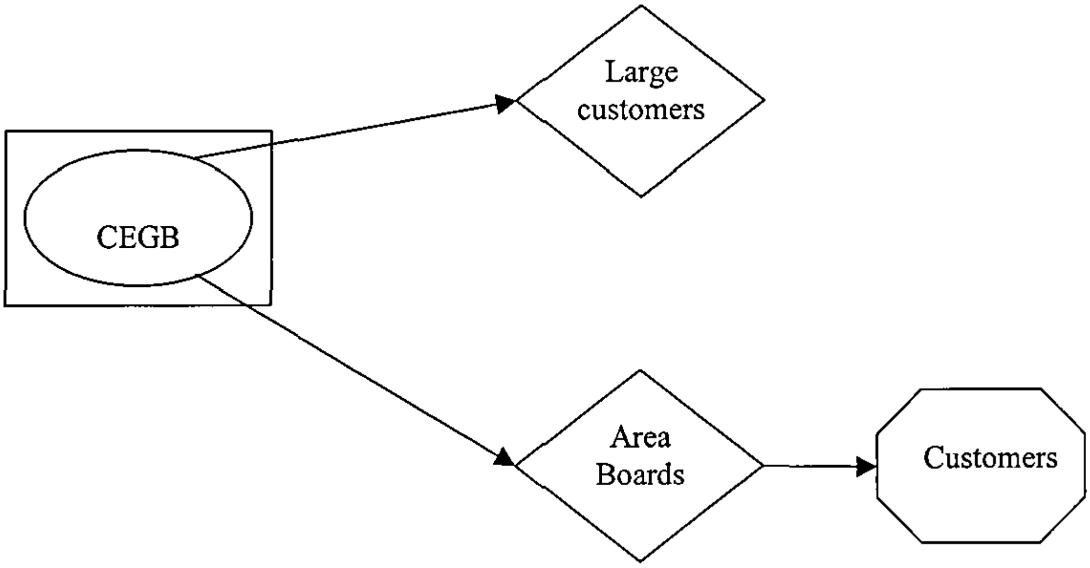

Figure 1.1 Vertically integrated monopoly

One of the main ideas, which evolved from the restructuring of the industry in England and Wales was that it was possible to separate the transportation of electricity from the energy itself. The changes that had taken place in the generating industry in itself pushed the debate forward New technology made turbines more efficient Combined with declining gas prices and the removal of the prohibition on gas burning, the optimal size of plant decreased considerably in the 1980s and 1990s, as gas fired stations replace coal and oil fired plant.

As the optimal size of plant started to decline rapidly in the 1990s with combined-cycle gas turbines becoming the technology for new entry, the generation market was no longer characterised as having natural monopolistic tendencies When the British government privatised the industry in 1990 and 1991, this was taken on board Therefore the electricity industry was unbundled into four key stages from production to supply. Each of these will be discussed in the thesis. Chapter three critically looks at the current trading arrangements and the changes which are expected to take place in the next few years due to pressure from government and customer bodies. They have argued that the trading arrangements should move away from a centralised pool mechanism to a decentralised bilateral trading model The thesis argues in favour of keeping the existing electricity pool with some modifications that reduce strategic behaviour. Changing to a system, which has a small balancing market may reduce liquidity and deter new entry, which is precisely what the regulator does not want to happen. The chapter also supports the lifting of the moratorium on new gas power stations. The moratorium hampers competition in the generating industry Although it helps coal in the short term, it also shields the three main coal-burning generators from new competitors.

Chapter four investigates the claims that the generation market is competitive as the authors of the privatisation had envisaged. The analysis is based on an event study using half-hourly pool prices and demand data It considers the ability of the major generators to exploit the market based on their perceived market power.

Chapter five examines the way electricity is priced along the transmission network. This was inspired by the complaints concerning the way the major generators have been able to strategically behave, when a constraint has appeared in the system The over-dependence of generators positioned in the North of England has led to the current pricing policies of transmission being questioned. Indeed the chapter argues that present practice does not encourage generators to locate in the South of England. Planning position is obviously a concern, but the fundamental pricing policy should not lead to prices being averaged across the country. Economic signals are not present when new investment in generating units is being considered.

The chapter then reviews the literature on transmission pricing to see how the signals for new generation can be improved Papers by Bohn et al (1984a) and Chao and Peck (1996) dominate the ideas which are put forward in this chapter Reforms which could be made to the England and Wales model centre on altering the pricing of transmission to reflect the costs which are imposed when increments or decrements to demand or supply are made by the marginal user. In other words, customers in the South of England and generators in the North should be required to pay more for access to the transmission network Conversely generators in the South and customers in the North would have a lower access charge. Transmission pricing is also important because of the structural reforms of the industry Generation and transmission were no longer vertically integrated as part of the CEGB. Location pricing therefore becomes relevant for signalling to existing and new generating companies where investment should be made geographically.

From April 2000, a new price control will be imposed on the distribution system. Chapter six therefore reviews the literature on how efficiency and productivity is measured based on a non-parametric approach This is important since the regulator will measure past productivity performance by the Regional Electricity Companies (Recs) for making some assumptions on price control. Data envelopment analysis and total factor productivity techniques were applied to a number of models, reflecting the inputs and outputs which were characteristic of the distribution network Ranking positions for each of the twelve England and Wales Recs were made This identified Eastern, Seeboard, and Southern in particular as the leading Recs in terms of performance since 1990. Northern recorded the poorest performance over the same time period. Of significance was the variation in the performance of the Recs, given that a yardstick approach had been adopted to encourage convergence towards the best performing Recs.

Figure 1.2 displays the new liberalised structure of the electricity supply industry (ESI) in 2000 The transmission network owned by the National Grid Company (NGC) and the twelve distribution companies (DISCO's) in England and Wales are characterised by a natural monopolistic environment Generation and retail supply (SUP) are open to competitive forces

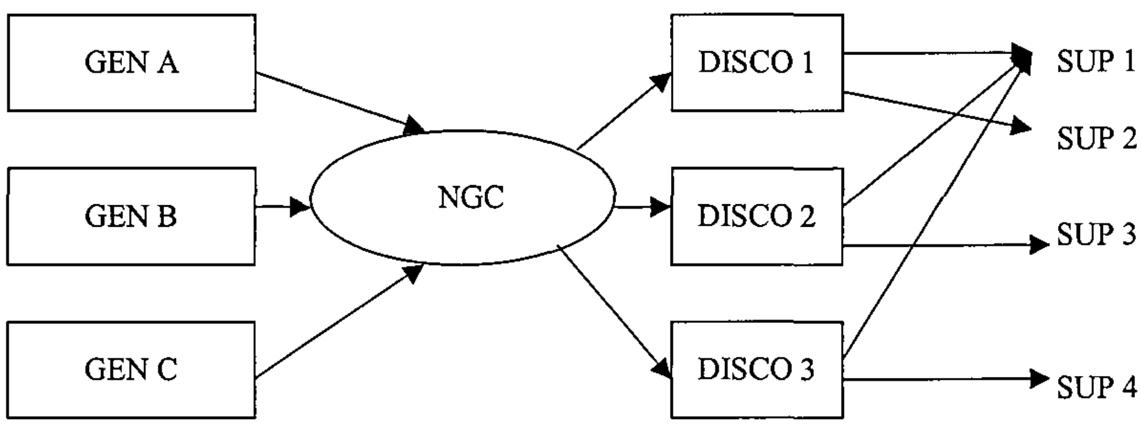

Figure 1.2 Liberalised electricity structure in England and Wales

The structure is such that a supplier has to pay an access charge to the distribution company, for the area in which it is seeking to operate. The theory surrounding access pricing is discussed in chapter seven, which looks at the issues, which are likely to dominate retail supply competition. Models are based on Armstrong, Doyle, and Vickers (1996) and Laffont and Tirole (1996). With the proposed adoption of a bilateral trading model, the implications for competitive supply are discussed, based on a model by Dobson and Waterson (1997)

New entry in retail supply will inevitably lead to innovative contracts The theory of self-selecting contracts is subsequently discussed in this chapter including an example of priority pricing. This is where the security of supply is chosen by the customer based on a variety of electricity contracts on offer The pressures towards vertical integration of generation and supply due to competitive forces are examined, as is the conditions for a contestable market. These are the issues that will decide whether retail supply is contestable, and delivers the benefits to the customer in the long run, in the form of lower prices and improved service

Chapter 2 Regulation

2.1 Introduction

Regulation is generally used as a last resort in markets, which are unable to open up to competition. The optimal structure and size of a firm is determined by an intricate set of relationships, reflecting among other things, production characteristics and information costs Economies of scale over the relevant market demand which lead to a minimum efficient scale is a sufficient condition for a natural monopoly in a single product market. Transmission and distribution are two sectors in electricity that support natural monopolistic characteristics. The subadditivity condition for these two sectors shows that the cost (C) of producing a given level of output (Q) is lower if handled by one firm compared with spreading the production over several firms, as demonstrated by equation 2 1 1

$$C\left(\sum_{j=1}^{m} Q_j\right) \leq \sum_{j=1}^{m} C(Q_j) \tag{2.1.1}$$

Generation and supply are sectors in the electricity industry that are able to support two or more competing firms, provided they have access to the essential facilities of transmission and distribution. With the introduction of efficient combined-cycle gas turbines (CCGT), the minimum efficient scale for generation plant is under 1000MW New technology has enabled competition rather than regulation as the best way of delivering lower prices for the consumer The same criteria applies to supply where the only requirement is that a company has the capability of utilising a large database of customers.

2.2 Historical context

The most prominent question facing a regulator of a utility who displays the characteristics of a natural monopoly is asymmetric information Applying the principal-agent model, two problems are typical. Hidden information is where the firm will have more knowledge of demand and costs affecting the industry compared to the regulator. Hidden action relates to conditions where the firm knows the degree of effort it has exercised to reduce costs whereas the regulator will be unable to know the effort applied by the firm Managerial slack will be difficult to observe by the regulator Therefore an incentive mechanism is required to induce the firm to increase effort, reduce costs, and thus improve productive efficiency, which will ultimately benefit the end-user.

One of the problems that a regulator has to avoid is being captured by the industry Stigler (1971), Posner (1974) and Peltzman(1976) have considered this possibility, where the regulator acts in the interest of the incumbents in the industry rather than in the customers or potential entrants interests There are obvious trade-offs when a regulator announces a new price regime It has to balance the wishes of the consumer for lower prices with the demands of the firms who want higher prices and profits. The more politicised regulation is, the more pressure there is on the regulator to deliver. This chapter attempts to review the literature on regulation starting with a decentralised regulated system and traditional cost-plus regulation Consideration is then given to the merits of intermediate and high-powered regulation and the latest developments in regulation based on the 1999 Distribution price control.

2.3 Decentralised regulation

Loeb and Magat (1979) show that by ignoring potential excess profits earned by a utility, a regulatory mechanism can be devised to ensure that the sum of consumer surplus $V(P)$ and producer surplus $\pi(P)$ is maximised In this principal (regulator) - agent (electricity company) model, the regulator is assumed to know the utility's demand curve $D(P)$, but does not have prior information regarding its cost function $C(Q)$. Marginal costs of regulated companies can be extrapolated provided the principal has information regarding the technical efficiency of the utility (γ). Henceforth the objective of policy in this model is to encourage the utility to reveal the true level of technical efficiency.

Using figure 2 3 1 below, if the true marginal cost is given by (γ_2), the electricity company will have the incentive to falsely report (γ_1) to the regulator. The Loeb-

Magat mechanism however will induce the utility to report (γ_2) by transferring the level of consumer surplus to the producer for each output level Therefore at output level Q_2, the producer will receive area $A+B+C$ instead of a transfer payment of area A when (γ_1) is reported. The utility consequently has an incentive to reveal the true level of marginal costs because it will receive a higher proportion (ϕ), of consumer surplus where $0<\phi<1$. Burns, Turvey, and Weyman-Jones (1998a) have shown that under this model a monopolist could receive a large transfer payment, which may be politically unacceptable However this model is normally used as a starting point to highlight the trade-offs which take place in regulation. In particular regulated firms need to be rewarded to tell the truth

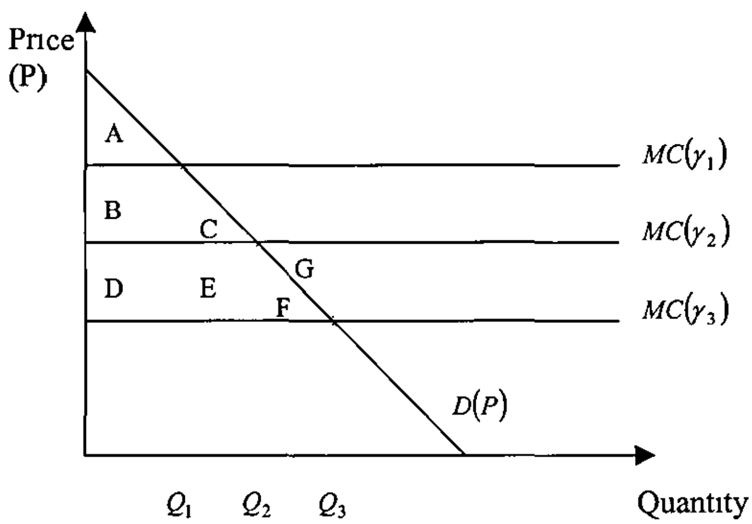

Figure 2.3.1 Loeb-Magat mechanism

2.4 USA model of cost of service regulation

The US model applies to an industry of investor owned utilities (IOU). Joskow and Schmalensee (1986) conclude that it is "the method used to determine prices that provide incentives, either good or bad, to regulated firms" (p.5) Rate of return regulation has been the dominant regulatory policy across utilities, since the Hope Natural Gas Company (1944) case. Accounting depreciation methodology is used to show that the return on investment deteriorates over time because of lower efficiency values. The regulatory commission publishes a maximum allowed rate of return on the utility's capital asset base, which subsequently determines allowed profit. The aim of this policy is to set a price reflecting the cost of providing the service to the customer.

Most of the IOUs are vertically integrated, providing generation, transmission, and distribution services. A utility will file tariff changes related to the level or structure of existing rates of return to a public utility commission, possibly due to a changing cost environment. The commission will then decide whether to allow or block these proposals. To illustrate the general idea of rate of return regulation, a private utility is assumed to maximise profit, π, subject to a published allowed rate of return constraint,

$$\frac{R - wL}{K} \leq s \qquad (2\ 4\ 1)$$

where revenue is defined by R, cost of labour is wL, level of capital employed is K, and a fair rate of return is denoted by s. Under this regulatory structure, the level of capital employed will affect the rate of return. For example a one unit increase in capital will cause a lower return on the investment Therefore if the actual return exceeds the regulated return s, the firm may increase capital investment to meet this constraint The objective for the firm is to maximise profits subject to the constraint in equation 2.4.1.

$$\max \pi = pX(p) - wL - rK - \lambda[pX(p) - wL - sK] \qquad (2\ 4.2)$$

where p defines the price of good X Differentiating equation 2.4.2 with respect to p will give

$$\frac{\partial \pi}{\partial p} = (1-\lambda)\{X(p) + (p - wL')X'(p)\} + (\lambda s - r)K'(X'(p)) = 0 \qquad (2\ 4.3)$$

Re-arranging equation 2 4 3 provides the famous Averch-Johnson model (1962) which incorporates the price elasticity of demand (ε) to explain that a monopolist will charge a higher price to customers who have a more inelastic demand

$$p\left(1+\varepsilon^{-1}\right)=wL'+\left(\frac{r-\lambda s}{1-\lambda}\right)K' \qquad (2.4.4)$$

In equation 2.4.4, the shadow price of capital, $\left(\frac{r-\lambda s}{1-\lambda}\right)$, is less than the market price of capital, r, so the IOU will use a level of capital in excess of the optimum, which takes place when the ratio of input prices equals the ratio of marginal products. A major result of the model is that an IOU will not allocate inputs efficiently, and will instead favour a bias in favour of capital. Profit in excess of the allowed rate of return will be confiscated, known as *profits confiscation regulation*. Equation 2.4.4 can be modified to take account of this phenomenon.

$$p\left(1+(1-\beta)\varepsilon^{-1}\right)=wL'+\left(\frac{r-\lambda s}{1-\lambda}\right)K' \qquad (2.4.5)$$

The degree of confiscation is modelled by β in equation 2.4.5. When profits are confiscated 100% beyond a level such that $\beta=1$, price is determined by marginal cost. Rate of return regulation therefore secures allocative efficiency, but at the expense of discouraging productive efficiency. Therefore there is a trade-off between equity and efficiency. In particular technical inefficiency will lead to a lack of effort by managers, in seeking to minimise the cost of production. It has been shown that the adoption of a rate of return mechanism for monopoly utilities will create a moral hazard problem. Customers in the longer term may end up paying higher prices for electricity if productive efficiency is ignored, since this is what will influence the future cost base. Concentrating on allocative efficiency therefore has its dangers as the discussion above has illustrated.

One of the problems with rate of return regulation is how it differs considerably from a competitive environment. Under a competitive regime, if demand exceeds supply, price will rise above average costs to induce new investment in extra capacity. If one utility incurs lower costs compared to a rival, for the same product, it will earn positive rent. Efficient investment decisions will be expected to receive a competitive rate of return. Rate of return regulation in contrast will not reward a utility with positive rent when investment leads to very high efficiency gains and lower costs Furthermore it can be shown that when fewer units of output are sold the price charged to customers will have to rise in order to meet recoverable income allowed under rate of return

Burns, Turvey, and Weyman Jones (1998) measure productive efficiency, by constructing a technical efficiency index, u, for the level of labour and capital employed by the utility to produce output $X(p)$:

$$\left(\frac{1}{u}\right)L(X(p)) \tag{2 4 6}$$

$$\left(\frac{1}{u}\right)K(X(p)) \tag{2.4.7}$$

where $0 < u \leq 1$. Since the utility cannot exceed 100% efficiency, it will maximise profit subject to the constraint $u \leq 1$ Profit is defined as:

$$\pi = (1-\beta)\left[pX(p) - \frac{(wL(X(p)))}{u} - \frac{(rK(X(p)))}{u}\right] + \lambda(1-u) \tag{2.4 8}$$

Technical efficiency is identified, by constructing Kuhn-Tucker first-order conditions:

$$\frac{\partial \pi}{\partial u} = \frac{(1-\beta)}{u^2}[wL + rK] - \lambda \leq 0, \quad u\left(\frac{\partial \pi}{\partial u}\right) = 0 \tag{2.4 9}$$

$$\frac{\partial \pi}{\partial \lambda} = (1-u) \geq 0; \quad \lambda\left(\frac{\partial \pi}{\partial \lambda}\right) = 0 \tag{2 4.10}$$

Providing the constraints are binding (i.e. $\lambda > 0$ and $u = 1$) the utility is technically efficient. Moreover the utility is able to keep some of the profits because by definition $\beta < 1$ from equation 2.4.9. This example demonstrates how incentives can be placed on the firm, and management will deliver higher technical efficiency in exchange for higher profit by having an appropriate mix of capital expenditure and operating expenditure consistent with profit maximisation, rather than acquiring more capital assets on which a return is earned Whereas in contrast, if the constraint is not binding $\lambda = 0$, $u < 1$, and $\beta = 1$ Complete profits confiscation will subsequently result in technical inefficiency. Averch and Johnson (1962) have shown that rate of return regulation in the long run will not prevent higher prices. Only incentives placed on the firm to reduce costs will have this desired effect.

Train (1991) offers a schematic interpretation of cost of service regulation Figure 2 4.1 below identifies a variety of feasible profit options in an unconstrained model By this Train means profits that would arise under a range of capital expenditure profiles K, when the rate of return is not regulated. Figure 2.4.1 would indicate that when a monopolist is not regulated, the firm would choose to use an input mix which set the level of capital expenditure at K_{max}, consistent with profit maximisation π_{max}. A regulated firm by contrast will have profit confiscated if the rate of return exceeds the regulated level, defined by the cross section line "allowed profit".

Under this condition profit is maximised at R, with a corresponding level of capital employed of K_R. However feasible profits are higher when less capital is employed, but under cost of service regulation, 100% profit confiscation would arise because allowable return is constrained to π_1 when a level of capital equivalent to K_{max} is employed. Productive inefficiency would arise because the amount of capital used by the firm would be higher than would be the case if profits were not confiscated to meet the regulated constraint. However once additional investment has been made, these resources will be utilised

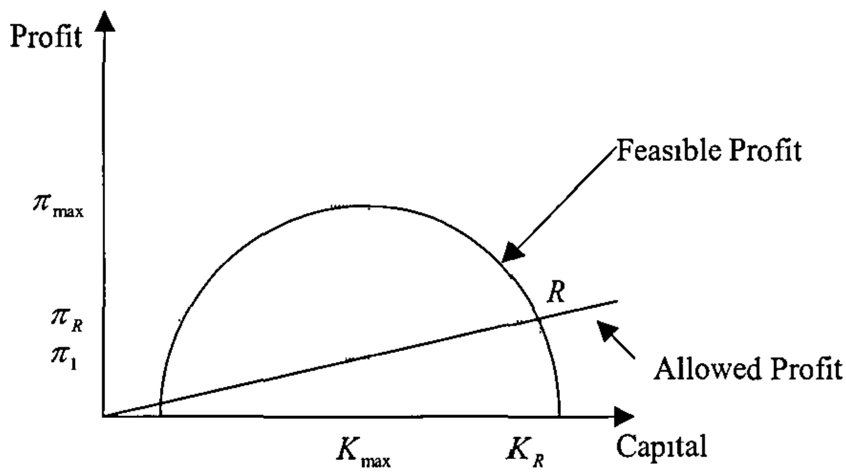

Figure 2.4.1 Train model of cost of service regulation

What are the consequences for capital expenditure when the regulator reduces the allowable rate of return, in response to political pressure? A reduction in s, in equation 2 4.1, will lead the utility to reduce capital investment. During the 1970s and early 1980s most private electricity utilities were given an allowed rate of return by a federal commission in the USA that did not fully recover the market cost of capital on investment projects. Investment in cost saving high technology plant and equipment was reduced with the effect of a high proportion of out of date technology in place to serve customers

The regulator has a fine balance to achieve between the customer and the utility A low rate of return imposed on businesses will not provide adequate reward for investment in capacity that improves productivity If the rate of return is set below (at) the cost of capital the firm will not produce (be indifferent between production and non-production). Alternatively if the rate of return is too high this will lead to the "gold plating" of service reliability. A concern with all types of regulation is the potential for a firm to operate at a sub-optimal level when a review approaches, in an attempt to avoid a much tighter regulatory regime in the future Managers will have this incentive if they fear that profits will be confiscated immediately after operating efficiencies have been achieved. Baron and De Bandt (1979,1981) have shown that if there are no automatic adjustment clauses that would otherwise push cost increases (or decreases) onto customers an efficient outcome is produced.

2.5 Intermediate power regulation

A key point to note from the previous section is that regulated firms have an incentive to choose an input mix of operating and capital expenditure that is sub optimal, and that managers in general do not have regard for efficiency and productivity. The intermediate power approach attempts to resolve this problem by using a principal agent game, between the regulator and a utility with costs that are unknown to the regulator (asymmetric information)

Laffont and Tirole (1993) have developed a number of models based on this problem, allowing for both adverse selection and moral hazard. Adverse selection is a major issue because the regulator is uncertain as to whether the utility's productivity type is high or low The danger is that a high productivity type could choose a contract, designed for a low productivity type because an efficient firm can always pretend to be inefficient without risk of discovery. However if an inefficient firm pretends to be efficient, it will be discovered very quickly Laffont and Tirole show how the design of a regulatory contract can prevent this from happening. Resolving the adverse selection problem also produces a neat result in mitigating the issue of moral hazard because management will have an incentive to explore all possibilities in undertaking cost reducing effort

The design of the contract is based on a transfer payment (standing charge) to the utility, which can be regulated while the unit price is left Ramsey efficient. This is Laffont and Tirole's dichotomy result. Before exploring the model, it is worth noting the following characteristics of the contract. Regulators cannot discover the firms type / effort however much money / effort they spend on their own estimation. This information can only be revealed by the firm. Regulators dislike transferring money to the firm to give it an incentive to reveal information because every £1 transferred costs £$(1+\lambda)$ to extract from consumers However this mechanism provides an incentive for the utility to reveal his/her productivity type and level of effort exerted, because the lump sum transfer has a shadow resource cost.

The level of lump sum transfer will depend on the option chosen from a menu of linear contracts. Two options are available in the discrete polar case of the model. The first is a high fixed payment which erodes rapidly as costs increase, which would be chosen by a utility who has a high productivity type. It would not pay for a low productivity type to choose this option because there is the danger that most of the lump sum will be eroded. Instead the low productivity type would choose the small lump sum payment which erodes slowly as costs rise.

Under universal service, there is no transfer payment, and instead a high marginal cost utility will see any cost savings passed onto the customer. In contrast a low marginal cost utility will be able to keep any efficiency gains. These costs represent the two extremes, and within this range, the rate of residual claimant on the cost savings will vary, and represents the general principles of sliding scale regulation.

In this simple model the regulator has a duty to recover the observed costs of the firm (C), and rewards the firm by passing on a transfer payment (t) from the customer, dependent on the firm's observed cost. Self-selection signals to the regulator whether the firm has a high or low cost structure. The cost of production is denoted as

$$C = (\beta - e)q = cq \tag{2.5.1}$$

where β is a technological parameter that will influence costs, e is the utility's effort exerted by management which is negatively correlated with costs, and q is the level of output produced The regulator observes total cost, but is unable to differentiate between β and e Low costs may arise as a consequence of high effort, a low technological parameter, luck, or a combination of the three. The regulator is assumed to have a set of prior beliefs about β. Laffont and Tirole (1986) assume a uniform distribution $F(\beta)$ over the interval $[0,\overline{\beta}]$. The lowest cost parameter has a distribution function value $F(\underline{\beta}) = 0$, while the highest cost parameter has a distribution function value $F(\overline{\beta}) = 1$ From this a density function may be written as:

$$f(\beta) = F'(\beta) = \frac{1}{\beta} \tag{2.5.2}$$

Consumer surplus is given by the gross benefit of output $[S(q)]$ minus the utility's net revenue $[R(q)]$. The utility will also receive a lump sum transfer payment $[t]$ from the customer. Management will weigh up the benefits of the lump sum payment against the disutility from exerting cost reducing effort $[\psi(e)]$ The regulator is aware of the firm's disutility of effort function. It follows that producer surplus is given by $U = t - \psi(e)$. Participation in the market is maintained by the following constraint.

$$U(\bar{\beta}) \geq 0 \tag{2.5 3}$$

The regulator induces truth telling by setting the increase in producer surplus that the utility receives, from inflating the reported technological parameter $[\beta]$, is equivalent to the saving in disutility from being able to reduce effort as shown by equation 2.5.4.

$$\frac{\partial U}{\partial \beta} = -\psi'(e) \tag{2.5 4}$$

The regulator will cover the shortfall between the firm's cost and revenue $C - R(q)$ as part of the revenue sufficiency rule Achieving the desired contract outcome requires that the efficient allocation of resources be distorted. Therefore revenue sufficiency condition and the lump sum payment will require the regulator to raise $[£(1+\lambda)]$ for every $[£]$. This is because the regulator wants to encourage inefficient firms to choose the low productivity type contract The regulator will maximise welfare.

$$\max S(q) - R(q) - (1+\lambda)[C - R(q) + t] + U \tag{2 5 5}$$

subject to the two constraints Once a contract has been negotiated the regulator will observe marginal cost $[c = C/q]$, and from this infer β The regulator knows the level of effort undertaken by the firm because it has information about the firm's disutility function However the regulator will have to incorporate subjective beliefs about the distribution of β as demonstrated by equation 2.5 6

$$\int_0^{\bar{\beta}} \{S(q) + \lambda R(q) - (1+\lambda)[\beta - e]q + \psi(e) - \lambda U(\beta)\} f(\beta)\partial\beta = \int_0^{\bar{\beta}} V(\beta)\partial\beta \qquad (2\ 5\ 6)$$

When the regulator maximises welfare under complete information, the marginal benefit of reducing cost through more effort equals the marginal disutility of effort when $[\psi'(e) = 1]$.

$$\frac{\partial W}{\partial e} = (1+\lambda)[1 - \psi'(e)] \qquad (2.5.7)$$

In practice the regulator will have imperfect information about costs and effort. An adverse selection problem could arise because a low-cost utility may choose a contract that has been designed specifically for a high-cost utility The solution adopted by Laffont and Tirole (1993) is to maximise equation 2.5.6 subject to the incentive compatibility and participation constraints, using Pontryagin's maximum principle. There are two variables, the state variable $[U]$ and the control variables $[e]$ and $[q]$ The Hamiltonian of the problem is·

$$H = V + \mu U = V(\beta) - \mu(\beta)\psi'(e(\beta)) \qquad (2\ 5.8)$$

There are two steps for solving this model The first is to integrate backwards from $[\bar{\beta}]$

$$\frac{\partial H}{\partial \mu} = -\psi'(e) \qquad \text{and} \qquad \frac{\partial H}{\partial U} = -\mu = -\lambda f(\beta) \qquad (2.5.9)$$

Therefore.

$$U(\beta)=\int_{\underline{\beta}}^{\beta}\psi'(e(\beta))\partial\beta \qquad \text{and} \qquad \mu=\lambda F(\beta) \tag{2.5.10}$$

Secondly maximise the Hamiltonian to find the level of cost reducing effort used by the management of utilities

$$\frac{\partial H}{\partial e(\beta)}=(1+\lambda)f(\beta)-(1+\lambda)\psi'(e)f(\beta)-\psi''(e)\lambda F(\beta)=0 \tag{2.5.11}$$

$$\Rightarrow \psi'(e)=1-\frac{\lambda}{1+\lambda}\beta\psi''(e) \tag{2.5.12}$$

where $\beta=\dfrac{F(\beta)}{f(\beta)}$. It has been shown that the level of effort undertaken by the utility is less than the first best effort under full information and is explained by figure 2.5.1.

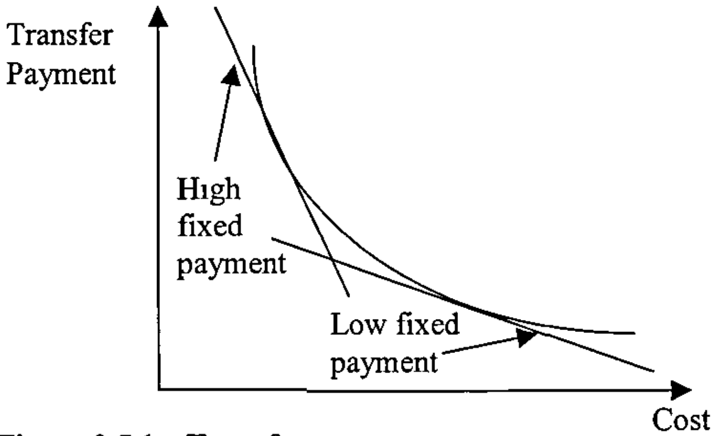

Figure 2.5.1 Transfer payment

This is because the contract allows inefficient firms to operate with less than optimal effort, by limiting the transfer payment given to high productivity type firms compared to low productivity type firms

2.6 High powered regulation

Profits confiscation has been found to be unsatisfactory, so when the government started to privatise the utilities in the 1980s it sought an alternative regulatory contract that would provide incentives for managers to increase efficiency and deliver benefits to the customer In 1983, Stephen Littlechild evaluated the different kinds of regulation that could be applied to British Telecom, including rate of return, sliding scale (output-related profit levy), a profit ceiling, and an unregulated monopoly. Littlechild chose a price cap incentive regulatory mechanism, known today as $RPI - X$. The report said that "the primary purpose of regulation is to protect the consumer" (Littlechild 1983, p.6) At the heart of the policy was competition which was to be preferred to regulation where it was feasible. His analysis was based on five criteria:

- protection against monopoly
- efficiency and innovation
- burden of regulation
- rivalry in terms of promoting competition
- revenue proceeds to the government and prospects for the utility.

Beesley and Littlechild (1989) set out the advantages of $RPI - X$ over rate of return regulation based on the grounds that managers would have greater incentives for cost efficiencies, because it would be the holder of the residual claim if efficiencies exceeded the price cap This would increase productive efficiency and promote innovation. In the next regulatory round, some of the x-efficiency gains could be passed onto the customer, in the form of lower prices

Flexibility is greater than under the old regime because the utility could adjust the price structure of services if they are included in a tariff basket. A rebalancing of the tariff basket may move charges closer towards cost reflectivity (Bradley and Price 1988), although it is possible that from the original position rebalancing may lead to charges moving further away from their true costs. In markets where demand is more elastic, price will be tending towards marginal cost. It also has the advantage that competitive services could be removed from the basket as and when it materialises. For British Telecom the tariff basket mechanism was represented by equation 2.6.1.

$$\sum_{i=1}^{n} P_i^t Q_i^{t-1} \leq (RPI - X) \sum_{i=1}^{n} P_i^{t-1} Q_i^{t-1} \qquad (2\,6\,1)$$

where P_i^t is the price of good i in time t, and Q_i^{t-1} is the weighting of the basket based on the previous years output level for good i Therefore the tariff basket is set such that the weighted tariffs submitted in period $[t]$ are no greater than weighted tariffs submitted in period $[t-1]$ after taking account of inflation, less an efficiency saving $[X]$ chosen exogenously Transparency would be enhanced through this simple process. In theory the opportunity for regulatory capture is diminished because the regulator only has to publish X without providing any reason for the decision. The weights are based on the previous years output figures so are not exogenously chosen by the firm. This is why the tariff basket resembles Ramsey properties, and entails consumer surplus rising over time as $[X]$ increases.

Rate of return regulation in contrast required the regulator, based on information from the utility, to measure the asset base of the utility and hence publish a fair rate of return. Costs also had to be allocated between competitive and monopoly services provided by the utility, and forecast of future costs and demands were made. Since there is less disclosure of decision making on the part of the regulator in the United Kingdom it is argued that there is less uncertainty over the level of X. Uncertainty would add a premium to the cost of capital, and inevitably long-term investment would be discouraged

Arms length regulation in the form of the price cap mechanism has not been perfect since it was introduced in the UK some fifteen years ago. The government has concluded that the regulatory framework needs updating and has argued that the 2000 Utilities bill is designed for "securing better regulation through improved transparency, consistency, predictability and accountability" (DTI 1999, p.8). Regulatory transparency is achieved through the requirement of regulators to publish reasons for key regulatory decisions. However the decision to replace an individual regulator with a regulatory board may lead to consensus decisions, and it could be argued a single regulator's determination to force through necessary change may be harder to achieve. Nevertheless the DTI cite a number of benefits for regulated companies including:

- increasing transparency of decisions and hence legitimacy will produce regulatory stability allowing companies to plan with greater confidence
- improving the predictability and consistency of regulation will provide strong incentives for an improvement in efficiency
- predictable and consistent regulation is aimed at removing unpredictable and inconsistent regulatory decisions
- lead to an increase in certainty and hence a lower cost of capital

The electricity regulator decided in 1995 to make an interim determination, less than a year into the price control, following evidence of significant cash balances from Northern Electric as they battled to maintain their independence against a takeover bid from Trafalgar House. The price control was tightened from $RPI-2$ to $RPI-3$ in 1997/98 onwards and was combined with an immediate P_0 reduction for customers of about 11% in 1996/97. Burns and Weyman-Jones (1996) interpret this as a positive correlation between the level of profits and the probability of profits confiscation A main argument against $RPI-X$ is the prospect of high profits being earned by shareholders. Although this is efficient, the political pressures are such that the regulator may be forced to re-open a price control and in the process lose confidence of the industry in keeping to the regulatory contract. However in defense of the price cap mechanism higher profits from productive efficiency will cascade down into higher efficiency gains, which are eventually passed onto customers in the following regulatory round Under the present inflationary environment, this leads to real price reductions.

Predictable regulation would have been reduced after the intervention by the regulator Political pressure ultimately forced the regulator to change policy. The danger with the price cap mechanism is that very efficient companies could earn significantly large profits, and though there is nothing wrong with this, pressure may lead to a decision that is detrimental to efficiency and productivity objectives These are the main ideas behind a sliding scale approach to regulation

The utility will maximise profits, $\pi(p^*) = p^* X(p^*) - wL(X(p^*)) - rK(X(p^*))$, after the regulator has chosen p^*. After re-arranging, the model incorporates the price elasticity of demand (ε) to show that the more price elastic the customer, the lower the price offered.

$$p^*(1+\varepsilon^{-1}) = wL'(p^*) + rK'(p^*) \qquad (2.6\ 2)$$

Burns, Turvey and Weyman-Jones (1998a) totally differentiate equation 2.6.2, so along the constant price locus p^*, the necessary condition for productive efficiency is:

$$\left|\frac{r}{w}\right| = \frac{\partial X/\partial K}{\partial X/\partial L} \qquad (2\ 6\ 3)$$

and is illustrated by figure 2.6 1

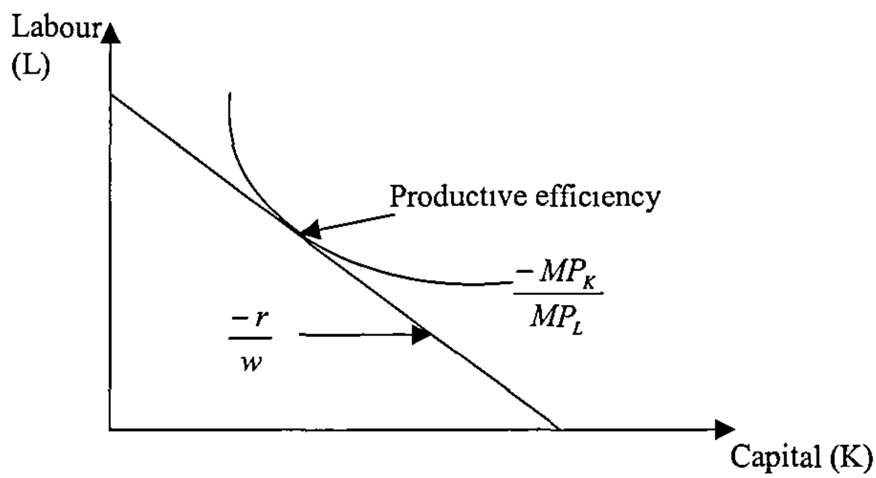

Figure 2.6.1 RPI-X is productively efficient

When X is initially set at the privatization stage, a number of parameters are decided which affect the costs incurred by suppliers These include the extent of cost pass-through, and whether productivity is based on an historical or forward-looking basis When X is reset, the regulator can change the design of the price control Companies who are unhappy about these changes, are within their rights to reject the package announced by the regulator The regulator then has the power to refer the company to the Competition Commission, as Ms Spottiswoode, the Director General of Gas Supply and Distribution has done in the Transco (BG) case (1996).

However there is a trade off between shareholders and customers. If the regulator appears more favourable to customers and delivers large price cuts it will mean that managers will have to make larger efficiency savings before profits are derived from the business Rate of return and $RPI-X$ are both concerned about providing an adequate rate of financial return for the utility. If companies are unable to beat the price cap, restructuring in the industry may take place, with the water sector being a prime example A number of companies are considering splitting assets from management and contracting out the latter in order to deliver the required price cuts. The cost of equity may rise following these developments if markets place a higher risk $[\beta]$ on the sector and is defined as:

$$\text{cost of equity} = \left[1 - \frac{\text{debt}}{\text{debt} + \text{equity}}\right]\left(r_f + (1+\beta)[r_p - r_f]\right) \quad (2.6.4)$$

where r_f is the risk free rate and r_p is the risk premium The regulator therefore cannot ignore these factors when re-setting X.

2.7 Current regulatory thinking

Rate of return regulation is based on actual costs, and does not provide incentives for regulated companies to cut costs. Price cap regulation is based on forecast efficient costs and is thus forward looking in its approach, set on the basis of predicted future cash flows" (Beesely and Littlechild 1989, p.461). A utility that makes efficiency gains that are faster than X will increase profit that is distributed to shareholders. Unlike rate of return regulation, $RPI-X$ does not make the length of the regulatory risk period endogenous. Bargaining power with companies it is argued by Beesley and Littlechild (1989) is greater as a consequence. Companies are more likely to disseminate information, negotiate tougher productivity agreements, and open up markets at a faster rate, if they are assured that improved performance and large profits in the last regulatory period will not result in the confiscation of profits in the following period.

Regulators have a commitment to ensure owners of the regulated companies are able to earn an adequate rate of return on new investment. Consequently a price cap is established at a level that ensures a forecast of operating costs is recovered along with an adequate return on both inherited capital and new investment Beesely and Littlechild (1989) suggest that in network industries it would be difficult to avoid relating the price control to a measure of company performance. These ideas are becoming recognised by other electricity regulators in the Netherlands and Australia.

The principles underlying Ofgem's approach to the 1999 distribution price control are set out in this section. An average revenue calculation is made by Ofgem and is expressed by equation 2 7.1.

$$M_t = P_0(1 + RPI - X)^t \qquad (2.7.1)$$

Revenue, M_t will decline by an initial price cut P_0 followed by the rate of expected productivity improvements inferred by X. This is based on an equal split, between average revenue per kWh distributed and average revenue per customer serviced by the company. These splits are both weighted by voltage class. The control was designed to discourage companies from increasing demand (if revenue was based solely on units distributed)

At the beginning of the consultation process, regulated companies are required to provide Ofgem with detailed information on operating costs for the beginning of the control period and capital expenditure projections for the period of the new price control. The primary objectives of Ofgem in the review has been to

- strengthen the incentives on companies to increase efficiency and reduce costs
- maintain sufficient revenue for a high level quality of supply
- finance new investment
- allow appropriate return on capital

Data envelopment analysis and productivity analysis could be applied for a comparative analysis of companies (see chapter six). Ofgem however used econometric analysis to measure this factor, and constructed operating expenditure projections $\left[OPEX^{*}\right]$, capital expenditure projections $\left[CAPEX^{*}\right]$, and depreciation $\left[DEP\right]$ of the network, which reflects the efficiency frontier A weighted average cost of capital $\left[WACC\right]$ is derived by OFGEM as

$$\text{WACC} = \text{gearing} \times \text{cost of debt} + (1 - \text{gearing}) \times \text{pre - tax cost of equity} = 6\ 5\% \qquad (2.7\ 2)$$

A present value (PV) of costs is calculated based on the information provided by the regional distribution companies after close scrutiny by Ofgem to move companies towards the efficient frontier The return on assets is based on taking the average of the opening asset value $\left[V_{t-1}\right]$ and the closing asset value for each year as expressed in equation 2.7.3.

$$return = \text{WACC} \times \left(\frac{\left[V_{t-1} + (V_{t-1} - DEP + CAPEX^{*})\right]}{2} \right) \qquad (2\ 7.3)$$

A present value of total cost over the five year regulatory contract is simply defined as

$$PV(\text{total costs}) = \frac{\sum_{t=1}^{5}\left[OPEX_{t} + DEP + return\right]}{(1 + WACC)^{t}} \qquad (2\ 7\ 4)$$

Present value of total revenue is calibrated so that it is equivalent to equation 2.7.4. However this is broken down into two components, price control revenue and excluded service revenue Price control revenue is profiled over the period 2000/01 to 2004/05 by assuming a residual adjustment of P_0 to the price control revenue in 1999/00, and then a reduction of $(RPI - X)$ in the remaining years of the price control.

The question that is fundamental to reviewing a price control is how the balance of revenue reduction is allocated between P_0 and the subsequent annual reductions referred to as X. If the X factor is based on the long-term rate of total factor productivity growth for the distribution sector, efficient companies will be able to meet the operating efficiency incentive Inefficient companies will have the potential to increase total factor productivity by a greater amount, and hence the problem of excessive profit would materialise. Chapter six produces total factor productivity results which could be used to resolve this problem, by basing the present value of costs on the efficient companies who lie on the frontier. These cost projections would include an adequate return on capital for an efficient company, and ensure that present value of revenue is equals present value of costs as discussed earlier.

The aim of regulation is to move the average company onto the efficient frontier cost level at the end of the price control period, referred to as benchmarking. The regulator could employ total factor productivity analysis to identify a suitable set of firms for which other companies can be compared with Chapter six suggests Eastern, Seeboard, and Southern would be suitable candidates because they achieve the highest productivity growth rates since privatisation in the sector. The only constraint the regulator has is the condition that cost reduction is compatible with service quality maintenance and financial viability A yardstick approach could also be used in the setting of the X factor Poor performing companies could have a tighter regulatory price control compared to efficient companies by setting a higher X for these companies The aim of this policy would be to move those companies onto the efficient frontier.

Returning to the size of the initial price reduction P_0, there are a number of glidepath options available to the regulator. If the regulator wants to move the average firm onto a frontier firm's cost function quickly it would impose a large P_0 reduction and a lower X factor, represented in figure 2 7.1 below by the non-constant glidepath gradient. Another possibility is to spread the cost reductions onto the frontier firm's cost function over the extent of the price control, so this would imply a lower P_0 reduction, which is equivalent to the X factor over the entire period i.e. constant glidepath gradient Other options would lie in between these two extremes. The water industry was given a price control between 1994/95 and 1999/2000, which represented a constant glidepath gradient.

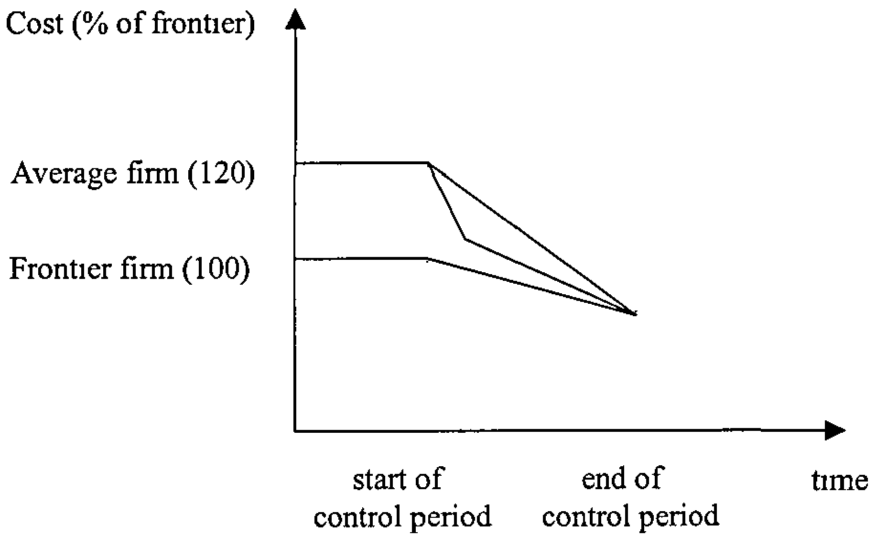

Figure 2.7.1 Illustration of glidepath options that a regulator could adopt

2.8 Ofgem announcement of Distribution price controls 2000/01 to 2004/05

Ofgem have decided not to implement yardstick regulation even though the evidence suggested that most of the productivity gains were industry wide, rather than inefficient companies moving closer to the efficient frontier (see chapter 6) Instead the regulator has chosen a uniform X factor of 3% for all companies. This is derived as follows. The range of inefficiencies measured by Ofgem was from zero for the frontier firms to 40 percent, with an average of about 20 percent (Ofgem 1999a p 33). Ofgem intends to eliminate the average level of inefficiency over the period 1997/98 to 2004/05, equivalent to an X factor of 3 percent. Inefficient companies have their allowed operating costs reduced by all of the measured inefficiency in 1997/98 costs, and hence have to reduce costs further than the frontier firms who have to reduce costs by the average annual rate of cost reduction.

Ofgem has rejected a constant glidepath, and have instead passed all of a company's efficiency savings from the previous price control back to the customer at the beginning of the new price control Therefore the efficient company from figure 2 7 1 has made 20 percent cost savings under the previous price control, which is given back to the customer in the form of a P_o cut It must then lower prices by 3 percent each year in real terms between 2000/01 and 2004/05 If it is able to make higher efficiency savings it will be able to keep the residual until the beginning of the next price control. In contrast the inefficient company has to pass on the 20 percent cut initially even though it has no cost savings to pass on, followed by 3 percent each year until 2004/05. Therefore the inefficient firm has to make larger cost reductions until it is able to receive extra income as the residual claiment.

Distribution Company	P_0 (%)	X (%)	Operating cost reduction (%)	Actual Operating cost reduction 1995-99 (%)
Eastern	28	3	29	20
East Midlands	23	3	18	9
London	27	3	27	8
Manweb	21	3	24	12
Midlands	23	3	18	9
Northern	24	3	25	5
Norweb	27	3	19	3
Seeboard	33	3	28	13
Southern	19	3	23	20
SWALEC	26	3	19	11
SWEB	20	3	23	14
Yorkshire	23	3	22	9

Table 2.8.1 Ofgem price control 1999 (Ofgem 1999a, 1999b)

Unlike rate of return regulation, a price cap has been shown to incentivise companies to improve productivity in a way that mimics competition. However if the price control is applied incorrectly (draft proposals 1999) then the mechanism can send perverse signals. Ofgem initially ordered the two most efficient companies to reduce prices in 2000/01 by 34 percent and 28 percent respectively The two least efficient firms were asked to reduce prices by 28 percent and 24 percent.

2.9 Conclusion

Reform of regulatory policy was a major theme in the restructuring of the UK electricity industry. Beesley and Littlechild (1989) proposals for liberalising potentially competitive markets were acted upon, so free entry and exit was permitted in the generation industry and above 1MW supply market in 1990. Technological change would allow the remaining franchise supply market to benefit from rivalry in 1994 and 1998/99. Prior to the 1979 Conservative administration the government would set out guidelines instructing the electricity supply industry (ESI) to follow long-run marginal cost $(LRMC)$ pricing, which is a model of cost of service regulation. Moral hazard and asymmetric information were of prime concern because it was difficult to calculate $LRMC$. After 1979 the industry operated Ramsey prices in response to the new government's desire to impose a cash limit on the industry. Productivity remained low during this period as Burns and Weyman-Jones (1994) showed using non-parametric linear programming techniques

A new system of regulation was required to improve productivity of natural monopoly businesses. The theoretical model of $RPI - X$ required the regulator to set a value of X as an exogenous price cap, so a high powered incentive regime is maintained The amount of potential efficiency gain that can be re-directed to consumers should be based on expected growth in total factor productivity, which is why calculations were made for the distribution industry in chapter six The mechanism provides incentives for managers to increase productivity and beat the price cap to keep the residual profit, while regulating with a light touch.

Shleifer (1985) recommended yardstick regulation of local monopolies, such as the distribution companies in England and Wales, so there are incentives for companies to outperform the mean. However there are some concerns about this type of policy such as collusion on costs, problems of comparability due to specific factors, and the commitment to the regulatory price control. Beesley and Littlechild (1989) see $RPI - X$ as a mechanism that imposes price caps while at the same time promotes competition in potentially competitive areas i e retail supply where minimum efficient scale is low and technical innovation is high. However they recognise that price caps may be indistinguishable from rate of return regulation where cost estimates are forward looking.

The debate over the nature of regulation in the electricity and gas industry has largely been resolved The Utilities Bill (2000) recommends the continuation of $RPI - X$ as the main type of regulation although there is the possibility of adjustments made to the price cap through an error correction mechanism. But to all intense and purposes rate of return regulation has been rightly ignored, and the improvements in productivity made by the regional electricity companies since privatisation is attributable to the price cap environment

The regulatory regime has become tighter to operate in over successive determinations, as the regulator has passed on some of the productivity gains to the customer Very tight regulatory policies however are dangerous if they have the effect of confiscating all future profits, because the policy then returns to another form of rate of return regulation. Consequently there are significant dangers in government policy influence the decisions of the regulator over price setting and any other matter. One of the dangers of government influence is the loss of independence for the regulator.

The Water Industry is a case in point where under the expected Water Bill (2001), Ministers will have the power to fine companies for failing to meet targets such as mandatory leakage targets, and order companies to introduce new tariffs (social) Furthermore Ministers will be able to set targets for the companies to meet All of these additional powers for the Secretary of State will have a bearing over the price setting process undertaken by companies. The introduction of the vulnerable household tariff in water is a form of a private welfare state, because the remaining customer base will be required to subsidise these customers Vulnerable households have been defined by Ministers as those who are on benefit and have one of a number of special medical conditions requiring large consumption of water, and are on meters Far from reducing regulatory uncertainty and hence the cost of capital, some of the measures in the Utilities bill may increase uncertainty.

In the latest distribution price control (2000/01 – 2004/05) efficiency improvements made in the last year of the current regime (1994/95 – 1999/00) will be passed onto the customer in the following year This in turn does not provide adequate incentives for companies to improve efficiencies up to the final year of the price control. Instead companies will strive to make efficiency improvements in the first couple of years of a price control. An attractive option to overcome this perverse incentive would be to enable a firm who made efficiency savings in 1999/2000 to keep those savings for a full five years. This is a recommendation adopted by the Water regulator for the regulatory contract 2000/01 to 2004/05

I would conclude that the price control appears to resemble profits confiscation as the X factor is related to the performance of companies. The regulator calculates a stream of revenues which match the total present value of regulated revenue, based on a rate of return on net assets of 6.5% A drawback with this calculation is that if the rate of return on net assets exceeds 6 5%, the excess will be confiscated and given to the customer, so there is less incentive for managers to improve productivity.

Chapter 3 Generation and Electricity Trading Arrangements

3.1 Introduction

The electricity industry in England and Wales was deregulated in 1990 For many years electric power systems were regarded as exhibiting natural monopolistic characteristics Opponents of deregulation were concerned that quality and reliability of electricity services would decline. Nevertheless the National Grid Company (NGC) who is the system operator (SO), has managed to coordinate multiple plants successfully whilst minimising costs Furthermore it was assumed that high fixed costs of generation would render competition ineffective. New gas turbine technology made entry possible on a small scale of 300-500MW, and so the generation industry was transformed into a contestable market, provided there is free entry and exit

At the heart of the new trading arrangement in 1990 was the formation of a *deep electricity pool*, which traded electricity a day ahead It is an association of stakeholders in the industry where participants signed a contract referred to as the Pooling and Settlement Agreement (PSA) This chapter considers the literature on trading arrangements, and comments on the new proposals that sweep away the principles of a deep pool and moves towards a system of bilateral trading

Prior to deregulation the Central Electricity Generating Board (CEGB) owned and controlled the generation and transmission facilities Bonn et al (1984b) present a model that created a real-time energy market place using spot pricing The cornerstone of the trading arrangement had a centrally organised market but decisions to buy and sell energy were made by independent generators, and customers. The market mechanism replaced direct central control by allowing participants to respond to spot prices The design of such a market place was introduced to the England and Wales one-sided Pool, where the National Grid Company (NGC) made demand forecasts on behalf of suppliers and customers.

Bonn et al (1984a) stipulates that “the market will not be effective unless ownership of generating units is divided among enough firms to guarantee competition” (p.73).

However to sell the privatisation to the City of London, and to ensure that it was a success prior to the 1992 election, the main fossil-fuel generators were separated into two companies, National Power and Powergen This will be discussed later in the chapter, but suffice to say that there has been considerable debate over competition in the generating industry. Nuclear generation stations were not privatised at this stage because of the risks associated with decommissioning.

3.2 Derivation of the pool purchase price

When an electricity market is established, it requires universal agreement among participants of settlement methods. The market operator (MO) who is the buyer and seller of last resort settles imbalances between the day-ahead and actual power flows Buyers (customers) and sellers (generators) first of all must pay the owner of the grid for the right to use the transmission network, which is discussed in chapter five. If there is plenty of time between the buyers and sellers agreeing contracts before delivery, they are normally arranged bilaterally. However markets can operate as bulletin boards, enabling buyers to post bids, and sellers to post offers, and they may also provide brokering services. Short-term contracts such as a week or day ahead usually require centralised markets run by the market operator.

Specific contracts to suit the needs of participants (over-the-counter) are viable only when the contract covers a large volume, lasting for months or years. Transactions cost theory mean that it becomes very expensive for constructing shorter-term specific contracts so the standardised terms of contracts offered by the market reduce transaction costs from negotiations In the England and Wales pool, all physical flows over the network are decided by the central dispatcher (system operator), and are settled by the market operator.

An efficient price-setting rule means that in a centrally dispatched trading arrangement, the price should be high enough for generators to be prepared to supply. The price should also be lower than the marginal value placed on electricity by the buyer. These two conditions ensure that buyers and sellers accept the principles of central dispatch. An efficient bilateral trading system on the other hand should “permit all cost-saving energy trades” (Hunt and Shuttleworth 1996, p.150). The price of imbalances will determine whether generators follow dispatch instructions If the price of imbalance is lower than the cost of running their own plant, then the generator will on economic grounds refuse to dispatch plant. Furthermore the price of imbalance will affect the efficiency of investment decisions

If demand has to be rationed so supply and demand are in balance, the opportunity cost is the value of the electricity to the marginal user. The *Pool* in England and Wales defines system marginal price for a particular half-hour as the offer price of the highest cost generator currently running in the half-hour Figure 3.2.1 shows how the pool purchase price (PPP_p) is derived.

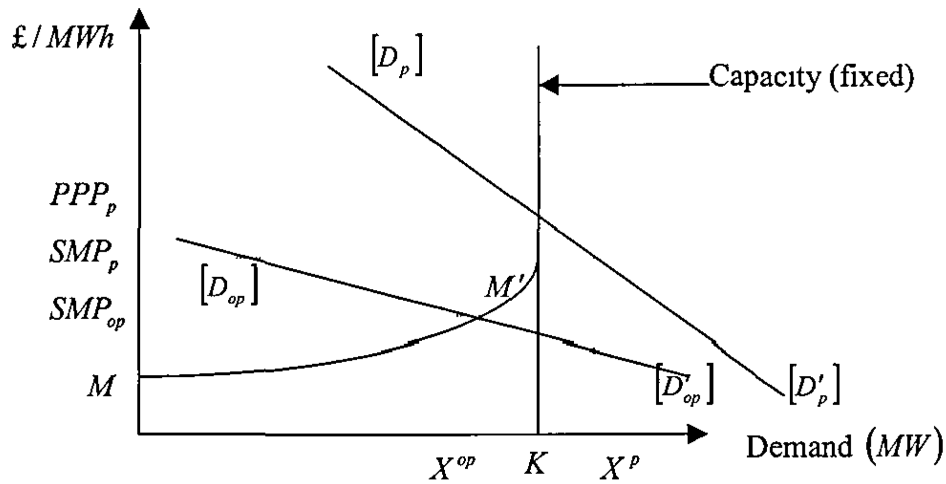

Figure 3.2.1 Derivation of pool purchase price

The line $[D_pD'_p]$ represents demand for electricity in peak-periods with demand in a specific half-hour$[X^p]$. Demand for electricity in off-peak periods has a line $[D_{op}D'_{op}]$ with a lower demand of $[X^{op}]$. Where demand is less than maximum supply, the pool purchase price is given by $[SMP_{op}]$. Under conditions of peak demand, if the price paid by customers is $[SMP_p]$ there will be an imbalance between demand and supply The current trading arrangements in England and Wales ration demand by pricing electricity according to the economic value. This is made up of the system marginal price and a payment for capacity, designed to signal to generators that new capacity is required

The present trading arrangements in England and Wales support the idea of maximising welfare:

$$\sum_{t=0}^{n} \int^{O_t} p_t(O_t)\partial O_t - c\frac{Q}{a} - \sum_{t=0}^{n} r_t O_t \tag{3 2.1}$$

subject to output at least equal to demand,

$$X_t \leq O_t \tag{3 2 2}$$

and a payment for providing sufficient generating capacity to the system and hence prevent the shedding of load,

$$\rho(VOLL - r_t)(X_t - Q) \geq 0 \tag{3 2.3}$$

where $[p_t]$ is the spot price, $[O_t]$ represents generating output, $[X_t]$ is demand, $[c]$ is capacity cost, $[VOLL]$ is the value of lost load, and $[\rho]$ is the probability of shedding load Availability of plant capacity is defined as $[a]$, so $\left[\frac{Q}{a}\right]$ represents the level of installed generating capacity $[Q]$ available Total running costs are stated in equation 3.2 1 as $\sum_{t=0}^{n} r_t O_t$ The regulated value of lost load $(VOLL)$ was set at £2/kWh in April 1990, and is adjusted annually for inflation.

The Lagrangian function of this model is expressed as:

$$L = \sum_{t=0}^{n} \int^{O_t} p_t(O_t)\partial O_t - c\frac{Q}{a} - \sum_{t=0}^{n} r_t O_t + \lambda_t(O_t - X_t) - \rho(VOLL - r_t)(X_t - Q) \tag{3.2 4}$$

where $[\lambda_t]$ will be interpreted as the short-run marginal cost $(SRMC)$ of operating the plant i e. the price that rations demand to available output. Kuhn-Tucker first order conditions are

$$\frac{\partial L}{\partial Q} = \frac{-c}{a} + \rho\left(VOLL - r_t\right) \le 0,\ \frac{\partial L}{\partial Q}Q = 0 \tag{3 2.5}$$

$$\frac{\partial L}{\partial O_t} = p_t - r_t + \lambda_t \le 0;\ \frac{\partial L}{\partial O_t}O_t = 0 \tag{3.2.6}$$

$$\frac{\partial L}{\partial X_t} = -\rho\left(VOLL - r_t\right) - \lambda_t \le 0,\ \frac{\partial L}{\partial X_t}X_t = 0 \tag{3 2.7}$$

$$\frac{\partial L}{\partial \lambda_t} = O_t - X_t \ge 0,\ \frac{\partial L}{\partial \lambda_t}\lambda_t = 0 \tag{3 2 8}$$

Substituting equation (3 2 7) into equation (3.2 6)

$$p_t = r_t + \rho\left(VOLL - r_t\right) \equiv SMP + LOLP\left(VOLL - SMP\right) \tag{3 2.9}$$

Equation 3.2.9 is an algebraic interpretation of figure 3 2 1, where there is a higher probability that customers in peak periods will experience load shedding compared to off-peak periods Therefore a "generation quality of supply component" is positive, and will rise to ensure demand is curtailed so the system is in real-time balance, thus avoiding a potential blackout.

There are three types of transactions implicit in the England and Wales pool rules· forward, option and spot transactions The day-ahead market is where generators make forward sales to the pool, based on forecasted demand by NGC The unconstrained schedule contains outputs for each half-hour These are treated as forward contracts to deliver energy in each respective half-hour for the following day. An options contract is also available, giving the pool (holder) the right but not the obligation to require a generator to produce electricity, and in return the generator is paid a fixed fee The option fee is derived similarly to capacity charges and is a payment for availability, which enhances system security. Generators who are available to supply but are not dispatched by the system operator receive an availability payment $[USAVP]$. Figure 3 2 2 explains how the current England and Wales trading arrangements operate

$$SMP + LOLP(VOLL - SMP) + USAVP$$

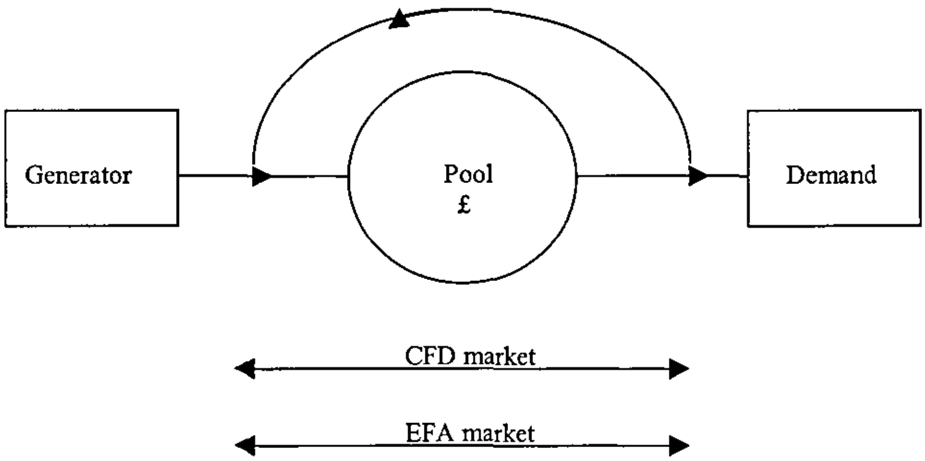

Figure 3.2.2 Trading inside the pool (generator payments)

All electricity generated is traded through the pool Fluctuations in demand particularly in peak periods can give rise to unexpectedly high pool prices especially when surplus capacity is low. The nature of the probabilistic mechanism contributes to this outcome. Customers can hedge against this by purchasing forward and option contracts A one-way financial contract-for-difference (CfD) is equivalent to a call option, which is called by the customer when the spot price is higher than the contract price. The generator must transfer the difference to the customer. It may also be structured to resemble a put-option for generators, so if the pool price is below the contract price, the supplier transfers the difference to the generator. A two-way financial CfD combines call and put options The electricity forward agreement (EFA) market represents standardised forward contracts usually associated with load shapes.

In the deregulated electricity industry, there will be no central decision-making process for deciding investment in generating plant unlike the old CEGB. Instead investment decisions will be based on profitability and minimising costs Generating units will be dispatched when the pool price is higher than their marginal energy costs. Lower operating costs will lead to higher revenues, and this helps to finance the capital costs of more efficient plant. The following simple model is used to characterise a system designed to minimise costs.

$$\sum_{v\geq 0}\left(\frac{Q^v c^v}{(1+i)^v}+\sum_{t\geq v}\frac{O_t^v r_t^v}{(1+i)^t}\right) \tag{3.2.10}$$

Equation 3.2.10 defines the present worth of total lifetime costs incurred in building and utilizing the capacity of vintage $[v]$ Turvey (1971) minimises these costs subject to constraints that include output from capacity of vintage $[v]$ must be less than existing capacity in year $[t]$

$$O_t^v - Q^v \leq 0 \tag{3.2 11}$$

and total outputs from capacity of all vintages in period $[t]$ must at least meet demand

$$X_t - \sum_{v=0}^{t} O_t^v \leq 0 \tag{3 2.12}$$

The Lagrangian function is set up as

$$L=\sum_{v\geq 0}\left(\frac{Q^v c^v}{(1+i)^v}+\sum_{t\geq v}\frac{O_t^v r_t^v}{(1+i)^t}\right)+\sum_{t\geq v}\frac{k_t^v}{(1+i)^t}\left(O_t^v - Q^v\right)+\frac{\lambda_t}{(1+i)^t}\left(X_t-\sum_{v=0}^{t}O_t^v\right) \tag{3 2 13}$$

Two of the Kuhn-Tucker first-order conditions are.

$$\frac{\partial L}{\partial Q^v}=\frac{c^v}{(1+i)^t}-\sum_{t\geq v}\frac{k_t^v}{(1+i)^t}\geq 0,\ \frac{\partial L}{\partial Q^v}Q^v=0 \tag{3.2 14}$$

$$\frac{\partial L}{\partial O_t^v}=\frac{r_t^v}{(1+i)^t}+\frac{k_t^v}{(1+i)^t}-\frac{\lambda_t}{(1+i)^t}\geq 0;\ \frac{\partial L}{\partial O_t^v}O_t^v=0 \tag{3.2.15}$$

Equation 3 2.14 specifies the investment rule: the discounted cost of capital is equal to the discounted shadow price of the capacity constraint. Equation 3.2.15 identifies the discounted short-run marginal cost, which is constructed in figure 3 2 3 for plants with different vintages.

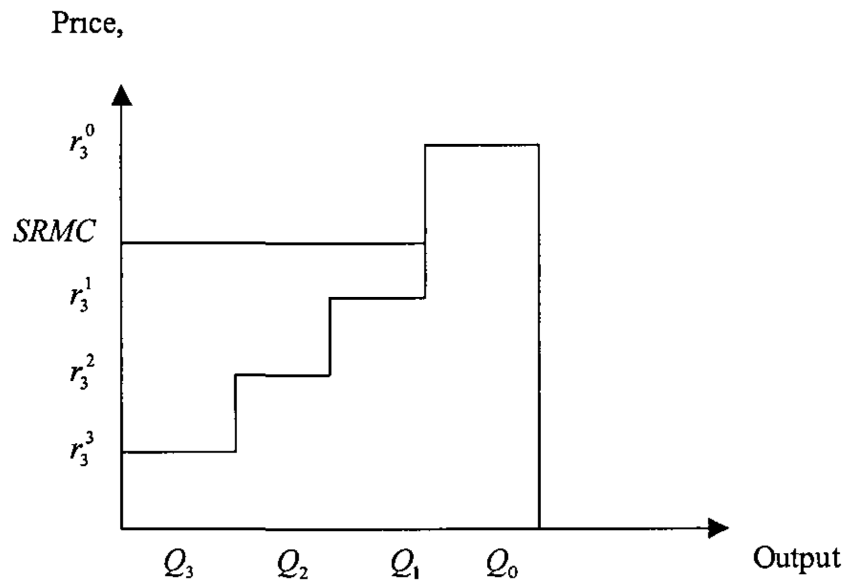

Figure 3.2.3: Shut down of plant

Plant with vintage capacity $[v = 0]$ is shut down from figure 3 2 3, if the discounted shadow price of the capacity constraint $\left[\frac{k_3^0}{(1+i)^t} > 0\right]$, because the plant will not be financially viable. This assumes there is no payment for availability If the availability payment covers the shadow price of the capacity constraint then generators will continue to operate those units. At present there is a surplus of capacity of around 20%. An NGC spokesperson has argued at an Offer seminar on trading arrangements, that they would not wish to see a reduction in this margin However there is a danger that without maintaining the present capacity payment in some form, which is designed to signal new capacity, there will be an inefficient use of plant and a shortage of capacity will develop If capacity was contracted out for a specific period of time to respond to capacity shortages, then the type of plant likely to be built for this purpose is low capital cost and high running cost plant This is unlikely to be the most efficient way to invest in new generating stock, and will lead to a sub-optimal life span for generating plants

3.3 Concern over Pool prices

Offer (1998a) conducted a study into the movement of pool prices following concerns over their high level, which commentators believed were unjustified in a competitive market The investigation found that total demand over the winter period 1997/98 "showed only a minimal increase over the two winter periods" (p.7). Plant margin over the period October to March 1997/98 was also "at the highest winter level for the last four years" (Offer 1998a p 8) Therefore the increase in SMP can not be explained by a substantial increase in demand or by a reduction in available capacity.

Increasing competition and falling costs should have led to falling prices, but although "average SMP in the spring and summer of 1997/98 was lower than in the early 1990s, it was in fact slightly higher than in 1995/96 and 1996/97" (Offer 1998a p 11). Table 3.3.1 below shows the derivation of pool purchase price (February 1998 prices). One can infer that there is an *inverse* relationship between annual average SMP and average capacity payments This means that the capacity payment mechanism is not working in the way it was intended, for recovering capacity costs and signalling when new investment should be made. The hypothesis should be that a shortage of capacity would simultaneously increase the spot price and capacity charge.

Year	SMP	Capacity Payments	PPP
1990/91	22.89	0 10	22.99
1991/92	22.92	2.20	25 12
1992/93	26 53	0.35	26 88
1993/94	25.46	0 56	26 02
1994/95	23 63	6 83	30 46
1995/96	22 45	8 71	31.16
1996/97	23 51	3 74	27.25
1997/98	29 62	1 63	31.25

Table 3.3.1 Time-weighted winter PPP (£/MWh)

A major concern expressed to Offer was that generators were pursuing a strategy of increasing SMP to compensate for low capacity payments. The level of the pool purchase price (PPP) was maintained because "the level of PPP and predictions of its future direction would significantly influence CfD renegotiations, and would be particularly important in the months leading up to the April contracting round" (Offer 1998a, p 19).

If SMP or PPP were high, the expectations would be that pool prices might rise further, or that they would not decrease in the immediate future to the extent as previously expected. This would entice customers and suppliers to sign contracts, which award a larger slice of consumer surplus to the generators

National Power and Powergen between them set SMP 70% of the time in winter 1997/98. Therefore they were better placed to influence SMP. If prices rise some generators would have to concede absolute levels of production (if demand reduced) Similarly competitive challenges wishing to expand production would lead to price reductions unless others were willing to reduce production. National Power and Powergen have reduced both output and capacity in a market whose total size has increased since Vesting. They have "closed 17,000 MW of older capacity and disposed of 6,000 MW of coal fired-plant, replacing this with about 6,000 MW of new CCGT capacity. The other generators have increased both output and capacity simultaneously. This evidence suggests that the two major players at the time were able to reduce output whilst not necessarily conceding market share.

Table 3 3 2 below shows that National Power and Powergen had load factors (LF) below 50%. National Power and Powergen, and Eastern were the major generators who had the capacity to raise output, based on their load factors. Eastern raised their output levels in 1997/98, while National Power and Powergen reduced output. An inference from this is that the actions of National Power and Powergen facilitated the increase in pool prices

Generator	Output TWh (1996/97)	Output TWh (1997/98)	% Change	Average LF %
NP	34 5	33.6	-2	46
PG	33.1	31.1	-6	47
Eastern	13 7	18.2	33	63
Nuclear Elec	26 0	24.0	-8	76
Magnox Elec	12 0	12.1	1	84
Interconnector	14.2	15 0	5	95
New Entrants	20 4	21.3	4	78
First Hydro	1.1	1.4	24	N/A
Others	1.1	0 9	-20	N/A
Total / Average	156 1	157 4	1	58

Table 3.3.2 Winter Output and Load Factors (Offer 1998a)

National Power and Powergen each reduced coal output, while Eastern increased it significantly. Average load factor over the period 1995/96 to 1997/98 "fell from 62% to 45% at National Power's coal-fired plant, and from 66% to 46% at Powergen's coal fired plant" (Offer 1998a p.29) excluding divestment of stations Eastern in contrast raised load factor of the divested plant from 53% to 61% for the winter periods This is persuasive evidence that the two main coal-fired generators have chosen to maintain margin and forsake market share Offer (1998b) submitted to the Government's Review of Energy Sources for Power Stations that recent pool prices might be "at least 10% above new entry costs of CCGTs, and that this represented a cost to customers of about £750m a year" (p 33)

3.4 Auction based models of the spot market

A strategy for generators in an auction would be to base the offer of supplying electricity into a pool based upon the cost of carrying out the contract, and information about competitors Game theory implies that if each generator correctly anticipates the strategies of competitors, the collection of strategies form *Nash* equilibria.

Hahn and Van Boening (1990) use experimental methods to compare the split-savings rule with a sealed bid-offer single price auction The split-savings rule works as follows Suppose a generator offers to sell electricity at £15/MWh, which corresponds to its marginal cost and a buyer is willing to purchase electricity for £25/MWh A broker assists in closing the trade by splitting the difference, so the price is £20/MWh. In general the broker uses the rule of bringing together the lowest price seller with the highest price buyer, and these trades continue until there is equilibrium Sellers and buyers will try to adjust their bids frequently in response to a change in the market condition For example if demand rises, generators will want to revise their bids upward to the economic value of electricity (generally system marginal price) Generators will have an incentive to overstate their costs towards the expected market price, while customers will have an incentive to reduce the value they place on electricity A split the savings rule is efficient if bids reflect the underlying cost characteristics of generating plant Inefficient dispatch is possible if the dispatcher does not have up-to-date information from generators and customers

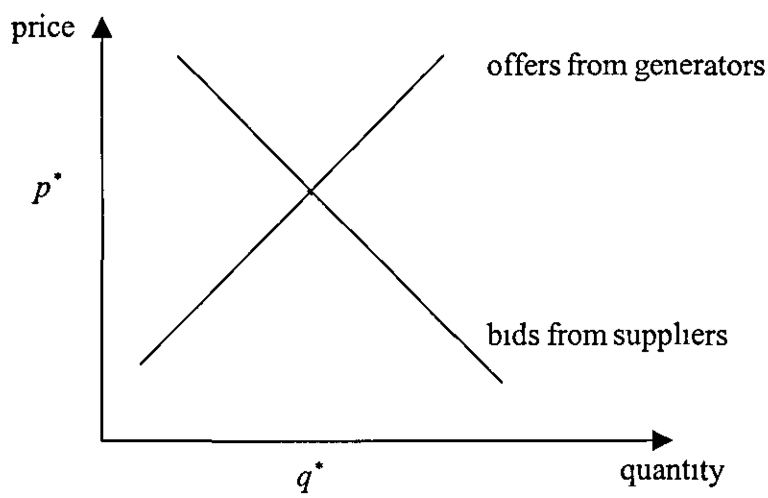

Figure 3.4.1 Single-price sealed bid

Figure 3 4 1 illustrates a single-price auction Suppliers submit sealed bids, and generators submit sealed offers. The market operator would rank the bids from high to low, and the offers from low to high. The market price $[p^*]$ is found by the intersection of the bid and offer schedules. Both forms of setting price are compared to the competitive equilibrium Hahn and Van Boening (1990) found that "efficiency was generally higher under the single price regime, but both institutions resulted in at least 90% efficiency" (p.1092). Statistical analysis also showed that under the split-savings rule, price deviations from the competitive equilibrium are more likely to be sustained.

The electricity pool in England and Wales is an example of a multi-unit auction. Wilson (1979) showed that in a uniform price auction, there are Nash equilibria that look collusive Each bidder will bid extremely aggressively for small quantities relative to her equilibrium share to deter others from bidding for a larger share of the market Firms that have infra-marginal capacity may be able to manipulate the system marginal price because of the design of the auction. Klemperer (2000) refers to an auction design where the firms have repeated common-value auctions of winning, and concludes that bidding a little more aggressively today is rational if it reinforces the bidder's reputation for aggressive behaviour tomorrow.

The electricity pool is characterised by very high frequency (daily) repetition of the auction with market participants having stable and predictable demand Klemperer (2000) argues that ascending auctions like the electricity pool are consequently more susceptible to tacit collusion, If one generator attempts to increase market share by submitting a flatter supply schedule, the marginal price will be lower for all dispatched units. In the next auction round (day $t+1$) other generators will be able to retaliate and submit even lower bids All parties concerned know this, so under this type of auction design steeper supply bids are more likely.

The unconstrained schedule in the pool consists of separate bids for each generating unit, one per day The bid includes a start-up price (£/start), no-load price (£/hour), and three incremental prices (£/MWh) for which the generator submits the range of each increment (elbow 1 and elbow 2) illustrated in figure 3.4.2 and is based on the characteristics of thermal plant generation. The start-up cost is the cost of starting up the generator, and the no-load component explains the cost per hour of being connected to the network Different incremental bids allow generators to reflect the cost characteristics of operating plant for different lengths of time and output levels.

For each unit National Grid Company (NGC) calculates the bid price as a function of output. Elbow 1 represents the second incremental price bid for output levels between elbow 1 and elbow 2. The third incremental price bid applies to output levels above elbow 2. This enables a price to be derived for each unit of plant submitted to NGC

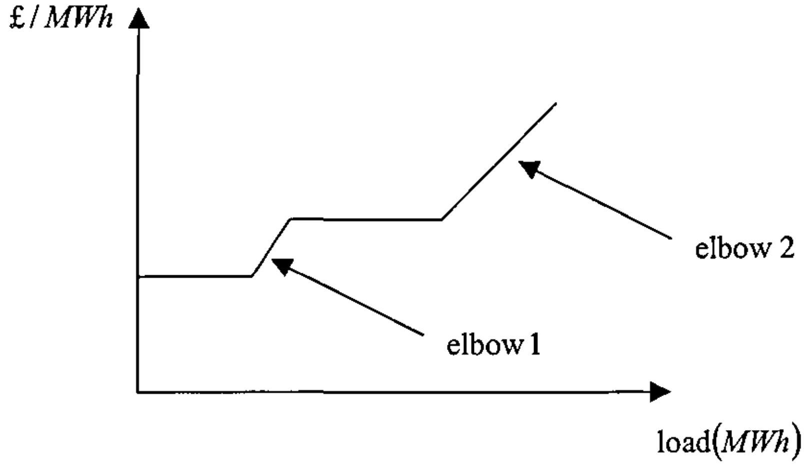

Figure 3.4.2 Multiunit bid function

The UK spot market is characterised by generators having a step-supply function (Fehr and Harbord 1993). Two generators each with 1MW of capacity will have different marginal costs unless they are symmetric One of the assumptions made by the authors is that each generator will have constant marginal costs for all units, which is not plausible for multiunit generators. This is one of the advantages of the supply function equilibria discussed in section 3 5, where linear marginal costs are assumed instead of constant marginal costs Section 3.3 identified National Power and Powergen's decision to reduce output from coal-fired mid-merit plant as a reason for high pool prices. Green (1996) shows that over a wide range of mid-merit output levels there are linear marginal costs, so this model will help to explain this argument

Fehr and Harbord look at a few scenarios, where two generators have asymmetric costs, and produce 1MW of electricity each If 1MW is demanded then the lowest bidder will be despatched, while both are despatched when 2MW is required. In a simple game, the two major generators, National Power and Powergen are bidding in response to a demand forecast from the NGC. British Energy will very often bid zero so it is always despatched, because it has low running costs and uses inflexibility markers that ensure that plant must be run. Therefore it will not determine the pool purchase price (PPP) National Power is assumed to be the more efficient generator.

Under the assumption of a competitive environment, and normalising National Power's marginal cost to zero, price equals zero. When demand $[d]$ is $1 < d \leq 2$, price equals the marginal cost of Powergen $[c]$

In a rivalry game, each generator has a strategic trade-off. bidding low reduces the risk of not being dispatched; bidding high increases the system marginal price (SMP) if it is the marginal generator. Figure 3 4.3 illustrates a step-supply function

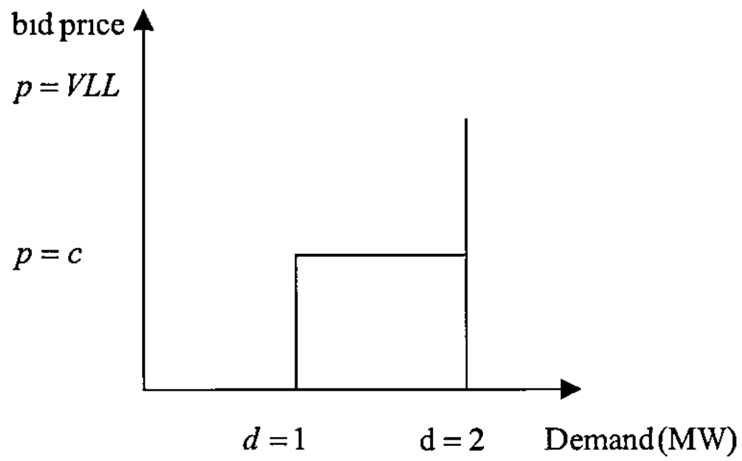

Figure 3.4.3 Step supply function

Throughout a low demand summer period, assume Powergen bids at $[p = c]$ while National Power undercuts and sets $[p = c - \varepsilon]$. This is characteristic of Bertrand competition, which was envisaged at the outset of privatisation. However the evidence does not point in this direction, rather it supports the view of a Cournot duopoly market When demand is low at $[d = 1]$, price will remain above the marginal cost of National Power. If demand is high $[d = 2]$ then both generators are dispatched, with National Power bidding at $[p = 0]$, while Powergen submits a bid $[p = VLL]$. The pay-off for each generator will be the net effect of $[SMP - MC]$ In both cases there is a *Nash* equilibrium from the pure strategies

However if demand lies between these two values, the only Nash equilibrium is one involving mixed strategies with generators randomising their bid prices according to an optimally chosen mechanism. If the probability of $[d = 1]$ is 0.75, then the probability of $[d = 2]$ is 0.25. Given expected demand of 1 25, one of the generators will not be completely despatched Subsequently there will be a substantial risk of inefficient despatch under mixed strategies. For example, if National Power bids $[c+\delta]$ but Powergen marginally undercuts, then Powergen has a payoff $[\delta]$, while National Power despatches 0.25MW and receives a lower pay-off $[0\ 25(c+\delta)]$. The risk is that the low cost generator will end up being the marginal despatcher, which is sub-optimal.

Wolfram (1998) builds on the work of Fehr and Harbord (1993). Two generators are assumed as usual, GenA (portfolio of plants) and GenB (single plant) GenA may have private information about GenB's bid based on the distribution $[F(b^B)]$ and the range $[\underline{b},\bar{b}]$ Although GenA orders the bids for $[N]$ plants $[b_1^A,\ ...,b_N^A]$, Wolfram studies the incentives for GenA to change the bid for a given plant $[b_i^A]$ GenA's expected profit is derived as

$$\text{Expected profit} = \text{Profit} \times \begin{pmatrix} \text{probability GenA} \\ \text{dispatched only} \end{pmatrix} + \text{Profit} \times \begin{pmatrix} \text{probability GenB} \\ \text{dispatched as} \\ \text{marginal plant} \end{pmatrix}$$

The first term is GenA's profit when all her plants are dispatched of which one of them will set the marginal price. The second term is associated with GenB setting the marginal price, resulting in $[i-1]$ plants contributing to GenA's profit. Using the notation of Wolfram, GenA's expected profit is

$$\pi^A\left(b_i^A, b^B\right) = \sum_{k=1}^{i}\left(b_i^A - c_k\right)x_k\left[1 - F\left(b_i^A\right)\right] + \int_{\underline{b}}^{b_i^A}\sum_{k=1}^{i-1}\left(b^B - c_k\right)x_k f\left(b^B\right)\partial b^B \qquad (3\ 4.1)$$

where $[x_k]$ is the capacity of GenA's $[k]$ plant, and $[c_k]$ is the marginal cost of that plant The first-order condition for maximising GenA's profit is:

$$\frac{\partial \pi}{\partial b_i^A} = \sum_{k=1}^{i} x_k\left[1 - F\left(b_i^A\right)\right] - f\left(b_i^A\right)\left(b_i^A - c_i\right)x_i = 0 \qquad (3\ 4\ 2)$$

How does a mixed strategy Nash Equilibrium evolve in a bidding game? A useful guide is given by McAfee and McMillan (1987) GenA assumes a given vector of bidding functions for the ith rival $\left[\underline{b}^{B}\right]$. These are used in equation 3.4 1 to generate the expected profit function for GenA, and the explicit behavioural bidding function that emerges from the implicit function in equation 3 4 2 GenB will rationalise its first order condition similarly. A mixed strategy Nash Equilibrium emerges when the set of bidding functions of A and B can be solved simultaneously and consistently. If the set of possible realisations implies that on average an equilibrium will occur from which neither would wish to deviate given that the other does not deviate, then this is a Nash Equilibrium This equilibrium is not assumed to occur in every realisation but only on average It also requires considerable costs of computation

A standard result in auction theory is that at such a mixed strategy Nash Equilibrium, the players bids are shaded less from their true valuations of being scheduled (marginal cost), the greater the number of other bidders, and it is this that allows us to infer competitive benefits to new entry in a game that assumes asymmetric information without marginal costs.

Letting $X_i = \sum_{k=1}^{i} x_k$, Wolfram (1998) presumes that any marginal changes in the bidding strategy of $\left[b_i^A\right]$ do not alter the ordering of A's plant Wolfram models the incentive that GenA has for increasing the marginal bid, so a high price is attained for all infra-marginal units when it sets the marginal price. Equation 3 4.2 is re-written to provide the following definition of the mark-up of price over marginal cost.

$$\ln\left(b_i^A - c_i\right) = \ln\left(X_i\right) + \ln\left(1 - F\left(b_i^A\right)\right) - \ln\left(x_i\right) - \ln\left(f\left(b_i^A\right)\right) \qquad (3.4.3)$$

Empirical evidence from Wolfram (1998) suggests that this mark-up is proportional to the number of plants already dispatched in the auction $\left[\ln\left(X_i\right)\right]$ There is also evidence that the mark-up decreases with plant size $\left[\ln\left(x_i\right)\right]$ because the income loss from not being dispatched is greater for larger size plants The results of this study imply that a solution to high pool prices is to reduce the number of plants that a single generator owns, so the number of infra-marginal units dispatched is smaller for the major generators. This is further examined in the next section.

3.5 Supply function equilibrium models

Klemperer and Meyer (1989) formulate a supply function equilibrium model based on uncertain demand. Green and Newbery (1992) applied these techniques to solve non-cooperative Nash equilibria. Load profiles (pattern of daily load) are not certain so these techniques appear to be suitable for an analysis of price-setting generators. Nevertheless by solving for supply functions which are deterministic functions of price and time, Green and Newbery (1992) are able to describe Nash Equilibria involving pure strategies.

Strategies are formulated for a one-period constituent game in isolation from other periods. In practice strategies are based upon a sequence of time periods, because the ex-ante day-ahead pool is repeated daily. Henceforth there is an opportunity for generators $[i]$ and $[j]$ to behave in a collusive way, leading to higher profits and a reduced level of welfare compared to the one-shot game. Green and Newbery (1992) defend the use of single-shot equilibria by arguing that "the possibility of collusion only worsens an already unattractive situation" (p.934).

The load duration curve at any moment during the day is defined as $[D(p,t)]$, where $0 \leq t \leq 1$ is time, and $[p]$ is the spot price less the marginal cost of supplying a very small amount of electricity. If generator $[j]$ has a supply schedule $[S^j(p)]$, net demand facing generator $[i]$ at time $[t]$ is calculated as $[D(p,t) - S^j(p)]$. The strategy for generator $[i]$ is a monotonically increasing supply function, mapping price to a level of output independent of time $[t]$. The reality of the pool is that a step-supply function is formed, though Green and Newbery (1992) suggest that bidding strategies may not be significantly different if a smooth supply schedule is used.

The dispatcher has the objective of minimising costs $[c(q)]$. Therefore profits attained by generator $[i]$ are derived as:

$$\pi_i(p,t) = p[D(p,t) - q_j(p)] - c[D(p,t) - q_j(p)] \tag{3 5.1}$$

Profit maximisation is found by taking the first-order derivative with respect to $[p]$:

$$\frac{\partial \pi_i}{\partial p} = q_i(p) + [p - c'(q_j)]\left[\frac{\partial D}{\partial p} - \frac{\partial q_j}{\partial p}\right] = 0 \tag{3 5 2}$$

Solving for the symmetric solution, each generator has the same electricity supply function, so that the (i) subscript is suppressed:

$$\frac{\partial q}{\partial p} = \frac{q}{p - c'(q)} + \frac{\partial D}{\partial p} \tag{3.5.3}$$

Green (1996) assumes the slope of the demand curve is constant $\left[\frac{\partial D}{\partial P} = -0\ 5\right]$, and marginal costs increase linearly with output (mid-merit output levels). Therefore each firm will have the following cost function

$$c_i(q_i) = \frac{1}{2} c_i q_i^{\ 2} \tag{3.5.4}$$

Each generator submits a schedule of prices and quantities for the day, so the supply function solution to the differential equation system 3.5 3 is linear:

$$q_i(p) = \beta_i p \tag{3.5.5}$$

Substituting equations 3 5 4 and 3 5 5 into equation 3 5.3·

$$\frac{q_i}{p} = \beta_i = (1 - \beta_i c_i)\left(\sum_{j \neq i} \beta_j - \frac{\partial D}{\partial p}\right) \tag{3 5 6}$$

where $[\beta_i c_i < 1]$ National Power and Powergen dominate the mid-merit market (coal-fired) according to the evidence in section 3 3. In this duopoly market, the slope of the supply function bids made by them is formed from equation 3.5 6 as:

$$\beta_{NP} = (1 - \beta_{NP} c_{NP})[\beta_{PG} + 0.5] \quad (3.5\ 7)$$

$$\beta_{PG} = (1 - \beta_{PG} c_{PG})[\beta_{NP} + 0\ 5] \quad (3\ 5.8)$$

Solving these two equations simultaneously produces Nash Equilibrium values of the two slopes, using an iterative process. Hence the slope of National Power's supply schedule is:

$$\beta_{NP}^{*} = \frac{\hat{\beta}_{PG} + 0.5}{1 + \hat{\beta}_{PG} c_{NP} + 0.5 c_{NP}} \quad (3\ 5\ 9)$$

Similarly the slope of Powergen's supply schedule is.

$$\beta_{PG}^{*} = \frac{\hat{\beta}_{NP} + 0.5}{1 + \hat{\beta}_{NP} c_{PG} + 0\ 5 c_{PG}} \quad (3\ 5\ 10)$$

Green (1996) assumes that Powergen is two-thirds the size of National Power, and so allocates cost parameters of £$1\frac{2}{3}/MWh$ to National Power and £$2\frac{1}{2}/MWh$ to Powergen. Table 3.5.1 shows the results of the iterative process based on these assumptions.

parameters		**guess**	β_2	**0.270756335**
c_1	1.67	Solve	β_1	0 336992295
c_2	2.5	Solve	β_2^{*}	0 270654004
$\partial D/\partial p$	-0.5	reconcile	$\beta_2 - \beta_2^{*}$	-0 00010233

Table 3.5.1 Duopoly iterative model

The slope of the supply function is derived from $[\beta_1 + \beta_2]$ If the supply function is chosen by all but one of the generators, the remaining generator's best response is to follow suit, making it Nash equilibria A move away from this strategy would make at least one of the generators worse off. The supply schedules must not cross either the lower stationary signifying competitive activity $(\partial p/\partial q = 0)$, or the upper stationary signifying the monopoly schedule $(\partial p/\partial q = \infty)$.

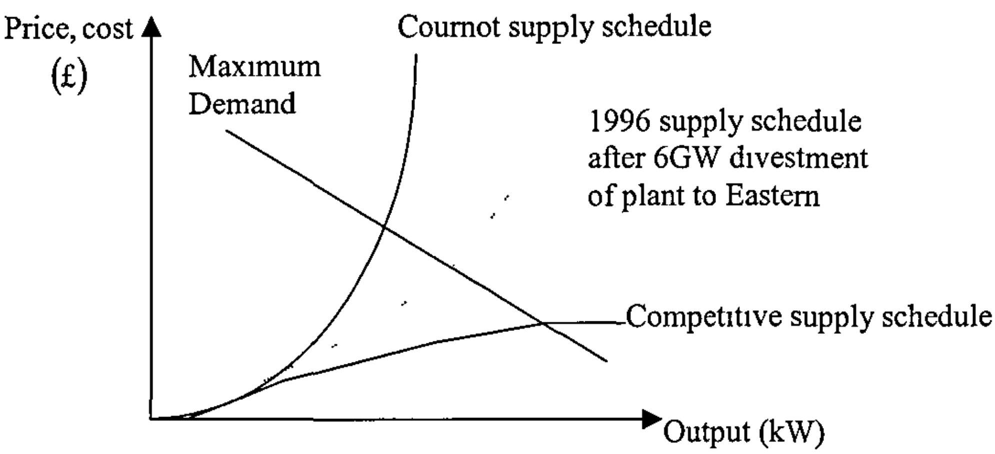

Figure 3.5.1 Supply-function equilibria

As demand increases, the gap between the Cournot and competitive supply schedule widens The interpretation behind figure 3 5 1 is that the baseload market has output and prices approaching competitive levels. The MMC report (1996) implied that the baseload market is competitive, so figure 3.5 1 appears to model the spot market closely The nature of the Cournot supply schedule implies that pool prices can rise to very high levels Offer has found evidence that over 1998 and early 1999, the incidence of price spikes increased dramatically, as table 3 5 2 illustrates. They use three definitions of price spikes· price exceeding £60/MWh, £70/MWh, and £80/MWh

No. of times SMP >	Q4 1996	Q4 1997	Q4 1998	Jan 1999
£60/MWh	11	178	234	180
£70/MWh	4	121	138	96
£80/MWh	3	93	117	59

Table 3.5.2 SMP price spikes (Offer 1999 table 1 p.4)

These price spikes occurred in periods of relatively low demand This is not consistent with the operation of an efficient market where prices reflect the underlying fundamentals Although average SMP for the first twelve months to 1998/99 have remained similar, the price spikes have increased significantly. This increases the risks (fluctuating pool prices), so contractual negotiations are likely to lead to higher premiums that are unjustified

For $[n]$ identical suppliers operating under Cournot assumptions, the highest output is given by:

$$q = \phi\left[\frac{n}{n+1}\right]; \qquad \phi' > 0 \tag{3.5 11}$$

This follows the standard Cournot result that an increase in the number of generators will move output closer to the competitive level After National Power and Powergen disposed of 6GW of plant to Eastern in 1996, figure 3 5 1 suggests that the supply function would have shifted down. Moreover the maximum price will be decreasing with the number of generators in the market, since the price function is stated as·

$$p = \psi\left(\frac{1}{n+1}\right); \quad \psi' < 0 \tag{3.5.12}$$

There is still a concern that the major generators are able to abuse their market power in the non-baseload market. The department for trade and industry (DTI) has accepted this argument, which has led to both National Power and Powergen disposing of a further 4GW of price-setting plant each in 1999. Therefore the supply function schedule should move closer to the competitive outcome Whether this will lead to a competitive generation industry remains to be seen If there is still an abuse of market power, further divestment of plant should take place, bearing in mind that if coal price-setting plant were divided among five firms of similar size, output would be $5/6$ the competitive level.

3.6 Contracts Market

Volatile pool prices increase the risks for both suppliers and generators If either of them hedges this risk in the contracts market, the financial risk is passed to another participant who is willing or able to bear the risk, or is in a better position to control it. For example a new entrant generator may want to insure against fluctuations in price, so the risk is shared with the counter-party on the other side of the contract who is exposed to the risk that the pool price will be lower than the price agreed in the contract. Since participation in the contracts market accounts for up to 90% of total output, this has to be considered when examining market power issues. Contracts are capable of reducing volatility, which covers the opportunity costs of risk averse traders.

Allaz and Vila (1993) noted that contract sales pre-commit the seller to more aggressive spot market behaviour, which induces rivals to sell additional contracts. In the current electricity trading arrangements, contracts for differences (CfDs) are the main type of financial contract used to hedge the risk of participants A one-way CfD is normally defined as a call option. The buyer will call this CfD when the pool purchase price (p) is higher than the contract price (f_{Gt}). The generator will subsequently transfer the difference to the buyer who hedged against the risk of higher electricity prices A generator does not have to supply the fixed volume of electricity stated in the contract. If other generators can produce electricity below its short-run avoidable cost, then it will choose to purchase in the pool instead of supplying itself. The pool therefore acts to improve the efficiency of generators A two-way CfD combines call and put options If the pool purchase price lies above or below the contract price, the generator will be paid the contract price, which is why a two-way CfD is equivalent to a forward contract

An initial portfolio was enshrined at Vesting, containing coal-backed contracts between British Coal and the two conventional generators, National Power and Powergen. At the same time, CfDs were agreed between the generators and the RECs These contracts protected British Coal until March 1993, when a new contract was agreed, and would run until March 1998.

Powell (1993) develops a contract model for examining the issue of market power in the generating industry Marginal generating costs are assumed constant, and generators are risk neutral. These are very improbable assumptions, since portfolio generators are unlikely to have constant marginal costs, and all generators do not have the benefit of a guaranteed market, so they are more likely to display risk-averse characteristics Using the assumption of risk-neutral generators, profit accruing to each generator is defined as:

$$\pi_{Gi} = pq_{Gi} - kq_{Gi} - x_{Gi}(p - f_{Gi}) \qquad (3\ 6.1)$$

where $[q_{Gi}]$ is output from the $[i]$ generator, $[k]$ is the constant marginal cost, $[x_{Gi}]$ is the forward output of generator $[i]$ from the CfD, and $[f_{Gi}]$ is the forward contract price. Assuming demand is uncertain, the inverse demand function is

$$p = A - q_{Gi} - q_{Gj} + \varepsilon \qquad (3\ 6.2)$$

Powell (1993) further assumes that both generators have symmetric costs. Substituting $[p]$ into equation 3 6 1, and differentiating with respect to $[q_{Gi}]$, the standard Cournot Nash output is

$$q_{Gi} = \frac{A - k + x_{Gi}}{3} \qquad (3\ 6\ 3)$$

Curtailing the ability of the generators to reduce quantity and hence raise the spot price by increasing contract cover is inferred from equation 3.6.3. The model assumes there are two dominant generators (representing a duopoly generating industry), who establish a strike price for CfDs based on the expectation of the pool price. The twelve England and Wales RECs then decide how much electricity to hedge, which involves them exhibiting Cournot characteristics in the contract market They maximise welfare by subtracting away the degree of risk aversion caused by the variation in profits that accrue to each of them. Green (1999) argues that suppliers are more risk-averse than generators because "they sell on very thin margins" (p 117).

Profit for each of the RECs is stated as:

$$\text{profit} = \text{pool quantity} \times \begin{pmatrix} \text{tariff - } & \text{expected} \\ \text{price} & \text{pool price} \end{pmatrix} + \text{contract quantity} \times \begin{pmatrix} \text{expected} - & \text{contract} \\ \text{pool price} & \text{price} \end{pmatrix}$$

Welfare $[W]$ is constructed as·

$$W = q_{Rt}(t - E(p)) + x_{Rt}(E(p) - f) - b(q_{Rt} - x_{Rt})^2 \sigma^2 \tag{3 6 4}$$

where $q_{Rt}(t - E(p))$ is the difference between the customer's tariff and the expected pool price, $x_{Rt}(E(p) - f)$ explains the cost of the hedge if the spot price is lower than the strike price; and $b(q_{Rt} - x_{Rt})^2 \sigma^2$ explains the risk to the REC of electricity being un-contracted The optimal amount of electricity contracted is:

$$\frac{\partial W}{\partial x_{Rt}} = -q_{Rt} \frac{\partial E(p)}{\partial x_{Rt}} - 2bx_{Rt}\sigma^2 + x_{Rt} \frac{\partial E(p)}{\partial x_{Rt}} + [E(p) - f] \tag{3 6 5}$$

Therefore the optimal futures hedge is

$$x_{Rt} = q_{Rt} + \frac{E(p) - f}{2b_{Rt}\sigma^2 - \dfrac{\partial E(p)}{\partial x_{Rt}}} \tag{3.6 6}$$

The incentive for the generators to raise the contract price is greater when RECs are characterised by a high degree of risk aversion, because the demand for hedging contracts becomes more inelastic. Based on the assumption that the generators act as a monopolist, and thus collude in both spot and contract markets, Powell proves that the equilibrium quantity of contracts is less than total output generated Hence the spot price will exceed a competitive market scenario When the market is fully contracted, pool prices will converge towards the competitive level.

A liberalised supply market for all consumers is likely to lead to a decline in multi-year contracts, and "increase the importance of the annual contract round" (Green

1999, p.108), which takes place each winter. Green (1999) designs a contracts model using backward induction from the supply function equilibria, and shows that a generator with Bertrand conjectures (total output fixed) and hence $[\partial x_j / \partial x_i = -1]$ will cover all of its expected output in the contract market This will drive the price down to short-run avoidable costs A generator with Cournot conjectures (other firm's output is fixed) defined by $[\partial x_j / \partial x_i = 0]$ will sell no contracts in equilibrium

The objective of each generator in this model is to maximise profits, given the revenue from pool and contract sales, so equation 3.5.1 is re-written as:

$$\pi_i = p^* q_i(p^*) + (f - p^*)x_i - C_i(q_i(p^*)) \qquad (3.6.7)$$

Equation 3 5 2, which denoted the profit-maximising supply function $q_i(p)$ is now modified to take account of the contract market

$$q_i(p) = x_i + [p - c_i q_i(p)]\left[b - \frac{\partial q_j}{\partial p}\right] \qquad (3\ 6\ 8)$$

where demand is defined as $[A - bp]$, and linear marginal costs are assumed Under the Cournot supply schedule,

$$\frac{\partial q}{\partial p} = 0 \Rightarrow q^a = \frac{bp^a + x}{1 + bc} \qquad (3.6\ 9)$$

Substituting $[q = \alpha + \beta p]$ into equation 3 6 9, the result shows that as the first firm increases the number of contracts sold $[x_i]$, the slope of the supply function $[\beta]$ will become steeper Faced with this, the optimal strategy for a rival firm will be to offer a lower quantity at each price, and so the first firm has been able to use contracts to increase market share. The rival generator will behave less competitively in the spot market, which will keep prices high. Green (1999) also throws more light upon why most electricity is contracted, and contract prices are often higher than pool prices

Equation 3 6.7 is adjusted to include risk-aversion on behalf of buyers, so expected profits are:

$$\pi^e = E\left[p\left(x_i, x_j\right)\right]\left[q_i\left(x_i, x_j\right) - x_i\right] + f\left(x_i, x_j\right)x_i - \frac{1}{2}cq_i\left(x_i, x_j\right)^2 \qquad (3\ 6\ 10)$$

Differentiating with respect to contract sales:

$$\begin{aligned}\frac{\partial \pi_i^e}{\partial x_i} = &\left[\frac{\partial p^e}{\partial x_i}\left(q_i^e - x_i\right) + \left(p^e - c_i q_i^e\right)\frac{\partial q_i^e}{\partial x_i} + f - p^e + x_i\frac{\partial f}{\partial x_i}\right] \\ &+ \frac{\partial x_j}{\partial x_i}\left[\frac{\partial p^e}{\partial x_i}\left(q_i^e - x_i\right) + \left(p^e - c_i q_i^e\right)\frac{\partial q_i^e}{\partial x_i} + x_i\frac{\partial f}{\partial x_i}\right]\end{aligned} \qquad (3\ 6.11)$$

Green (1999) uses the mean-variance utility employed by Powell (1993) to derive

$$f = p^e + \lambda\sigma^2\left(\left(q_i^e + q_j^e\right) - \left(x_i + x_j\right)\right) \qquad (3\ 6\ 12)$$

and prove that under the Cournot conjecture the generators sell contracts but $\left[\left(q_i - x_i\right) > 0\right]$ whereas under the Bertrand conjecture $\left[\left(q_i - x_i\right) = 0\right]$ This infers that generators have been able to earn a hedging premium from their strategies in the pool, giving them an additional incentive to sell contracts.

Power purchase agreement (PPA) contracts were issued in the UK (and throughout Europe) in the early 1990s to facilitate entry for independent power producers (IPPs) OFFER allowed RECs to hold equity stakes in IPPs because it was seen as a way of increasing the competitiveness of the generating industry However a higher number of generators at privatisation would have assisted the coal industry because pool prices would be lower than they are, thus reducing the rate of return for potential entrants. Newbery and Pollit (1997) investigated the restructuring of the CEGB, and found that it increased efficiency, but with excess entry of gas that would mitigate those gains.

If the incumbent generators limited the average price to just below entry price, by increasing contract cover, they could deter entry Profit maximisation occurs here because a higher price would induce entry, and hence lower the average price down to competitive short-run avoidable costs The advantage for incumbents is that they can raise additional revenue by increasing the spread of pool prices between baseload and mid-merit markets. An increase in volatility will increase the premium paid in the contract market for hedging the risk This is the type of strategy that is implied by Green (1999). The effect of entry deterring contracts is shown in figure 3 6 1 below.

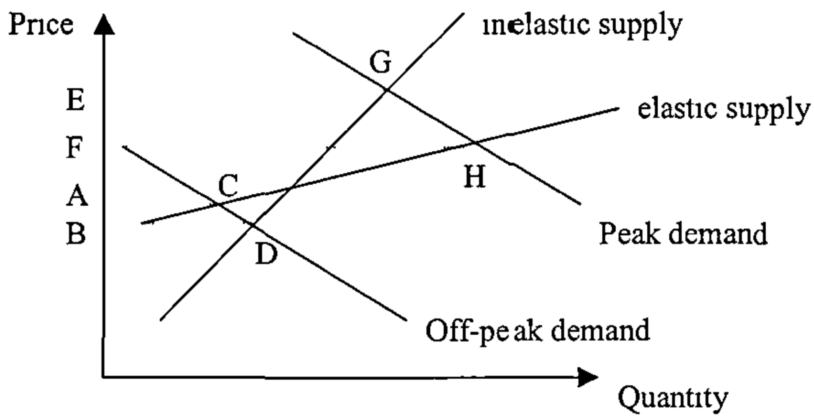

Figure 3.6.1 Gains and losses from elastic and inelastic supply functions

The customer gains from lower prices with an inelastic supply function in off-peak periods, denoted by the area ABCD In contrast it loses from higher prices in peak periods, by area EFGH The net effect is that customers will be better off under a more elastic supply function The variability in prices will be lower under this regime As the number of generating companies increase, the supply function becomes more convex, and with this brings the desired lower range of pool prices Newbery (1998a) concludes that more volatile prices are evidence of a less competitive generating market. If entry is characterised by lower variable costs (modern CCGT units) compared to the incumbents, new plants would run continuously on baseload and supply inelastically with variations provided by older plant. Most importantly, the number of price-setting generators would remain unchanged, and the evidence from Offer (1998a) appears to support this argument

The combination of more efficient CCGT plant, and an expansion in nuclear generation as a result of increased output and availability, will push less efficient

CCGT plant into mid-merit generation. This is reinforced by evidence given by Powergen (MMC, 1996) who estimated that 21GW of baseload capacity is required by the year 2000, but 38GW will be available Merz and McLellan in evidence to the MMC (1996) argued that there is no technical reason for CCGT plant not being adapted to run as mid-merit plant They estimate that an additional 6GW of capacity is required by the year 2001/2002, and suggest that CCGT plant is the most economic method to meet this demand These events may enable IPPs to set the Pool prices more often, and thus increase competition into the generating industry. However this assumes there is free entry and exit into the market, which is clearly not reflected in the market given the selective gas moratorium on CCGT plants applied by the DTI

3.7 The problems of the existing electricity trading arrangements (ETA)

The guiding principle in the deregulation of the electricity industry in 1990 was to open up the supply and generation markets to competition, since these two sectors were not characteristic of natural monopolies. The pool structure (figure 3 2 2) was created to facilitate vertical unbundling of the electricity supply industry. Nevertheless the pool soon came in for criticism particularly from consumer bodies If short-run avoidable cost set pool prices for most of the time, and in the long-run the marginal cost of expansion is close to the average cost, fixed costs will be recovered in a small number of half-hours, implying very volatile pool prices Volatility in pool prices had led to repeated demands for reform. In October 1997, the government took up the challenge and announced a review of current trading arrangements. However one of the important parts of the jigsaw was left out of the investigation. Namely the market power of the major generators was explicitly ignored in the review. This is strange since if the demand for pool reform was largely as a result of high electricity prices, then the review should have included the dominance of the price-setting generators.

Capacity withholding by the major generators led to both short-term distortions in making plant available and long-term investment decisions An entrant who observes high prices may believe that when additional capacity comes on stream, payments for capacity will fall substantially, thus deterring entry The high degree of sensitivity caused by the probability mechanism may also have led to plant being commissioned when it was inefficient to do so. Moreover it has not provided a long-term signal for future investment because relatively small changes to plant margin can lead to very large changes in capacity payments, particularly in peak periods

Newbery (1997) argues that the loss of load probability $[LOLP]$ greatly overestimates the risk of system failure, since it is not an estimate of the risk of failure on peak days, "but on randomly chosen days, assuming negligible supply responses, little demand responses, and based on out-dated information" (p 16). Patrick and Wolak (1997) studied demand responses to pool prices for large customers paying pool prices in one REC's region. They found that own-price elasticities at the peak were typically less than –0 025, suggesting that demand responses were very low when high electricity prices kicked in. Furthermore it suggests that customers were prepared to pay a large premium to continue to demand electricity and avoid load reduction This would provide support for increasing $[VOLL]$ and reducing $[LOLP]$.

A competitive generating market rather than the removal of capacity payments is the key to lower pool prices When surplus capacity is high and capacity payments are low, the generators simply raise SMP to cover avoidable costs, so pool prices will not be affected by removing capacity payments (Offer 1998a). The ability of generators to manipulate the market has brought this mechanism into disrepute by failing to provide the intended signals, but the basic idea behind it is sound. Under a more competitive environment, capacity payments could provide a responsive signal to build more capacity, scrap obsolete plant, and ensure plant is available when most needed as argued by Tilley and Weyman-Jones (1997 BIEE). Capacity payments that provide remuneration for the sunk costs of new investments, which is important for an efficient market to function should not be scrapped.

The selective moratorium on building new gas-fired generating units diminishes contestible markets, because there is a smaller threat of entry Therefore it will be harder for lower cost CCGT plants to replace older generating sets, which act as a constraint on the market power of incumbents. Over-investment in capacity by incumbents has also been used to curtail potential entry. Another concern is that the ability of RECs to sign long-term contracts with IPPS weakens following the liberalisation of the supply market. RECs had previously taken equity stakes in independent power producers (IPPs), and used the franchise market to finance this investment. Without a guaranteed supply market, there are additional risks with pursuing the policy further, thus impeding the threat of entry.

Newbery (1998b) concluded that "divestiture would make no difference to bidding behaviour" (p 5). This was because the Eastern Group were required to make payments to Powergen and National Power of 0 6p/kWh, equivalent to a shadow price of coal pollution, because emissions targets set by the Environment Agency were binding This is explained by auction theory which says that when there is "almost common values" one firm will have an advantage over the other. However since April 2000 Eastern no longer make this payment to Powergen

Non-firm offers and bids remove most of the costs and risks associated with plant failure away from generators and transfer them to suppliers and customers The pool has been criticised for being a one-sided pool with no demand bids. It would be more efficient if customers and suppliers were responsible for demand forecasts rather than NGC, since it would place the risks in the hands of participants who can control them. A potential security of supply issue is the interaction of the gas and electricity markets A CCGT plant can be scheduled in the Pool day-ahead market, but since this is not a firm commitment, it has the option to sell gas into the gas spot market on-the-day, via the flexibility mechanism if profits from this sales are higher than selling into the electricity pool Offer hold the view that closer interaction between the two markets could improve security and competitiveness of both markets, so commercial decisions will be based on underlying opportunity costs and market conditions.

Governance arrangements allow for voting blocks to prevent change and respond to demand by participants The regulator cannot take steps to secure change to the Pool directly because there is no licence The most important reform of electricity trading arrangements in my view are the governance arrangements I believe that the ability to quickly respond to demand and change arrangements is vital. Innovations both domestically and abroad could then be adapted to the electricity market

3.8 Concerns over the review process

All markets have a short-term power exchange to facilitate the balancing of supply and demand Offers by generators and bids by suppliers and customers are firmer than in the England and Wales market. There is a separate Balancing Market (BM) to increase efficiency and real-time balancing because it allows participants to fine-tune their positions, compared to the day-ahead stage Capacity payments do not exist in most other countries. The Market Operator (MO) ensures appropriate mechanisms for resolving disputes, monitor the conduct of participants, and allow for market rules to be updated and changed where necessary Boards concentrate on policy issues and subsidiary committees act as the primary forum for discussion and development of rule changes All changes have to be approved by the regulator.

A major concern about the review has been the apparent willingness by Ofgem to accept that many of the alternative models from other countries could be implemented in the England and Wales model. Clearly the electricity market in Norway is different from the electricity market in California, and both are different to the England and Wales market What might have helped in aid of the review was to examine a model that resolved some of the problems with the existing arrangements but built into it a more competitive generating and supply sector.

The Scandinavian model that adopts a balancing market close to real time is dependent on hydro reserves In systems that are able to store the commodity like gas, a balancing market is advantageous. But in the England and Wales model, which at present uses fossil fuel as a large proportion of its fuel base, a balancing market may not be desirable Indeed it may even have problems which reduce the likelihood of lower electricity prices Generators, suppliers, and customers will have to contract for electricity without the insurance of having the opportunity to sell output through a liquid compulsory pool Although 90% of electricity is already traded under forwards contracts, what effect will a balancing market have on new entrants, when a compulsory pool is no longer an option? The risks will increase because there are no outside options to the contract except for a shallow balancing market. This may make entry less likely, so the prospects of lower prices in the long-term are diminished.

Newbery (1998b) notes that there is "essentially no difference from the present trading arrangements" (p.9). The dominant generators in the balancing market are likely to be those with flexible plant, who are the same dominant players in the present compulsory pool, so the issues of market power remain A thin balancing market will make prices less predictable, forcing participants to trade outside the Pool. A financial contract replicates a physical bilateral contract, but the former has desirable efficiency qualities for cost minimising dispatchers. A financial contract for difference (CfD) allows a generator to purchase all of it's contracted electricity in a compulsory pool if costs are lower in the pool compared to producing electricity themselves in a specific half-hour. The ability of generators to perform this role in a thin balancing market is limited.

3.9 Proposed Trading Arrangements

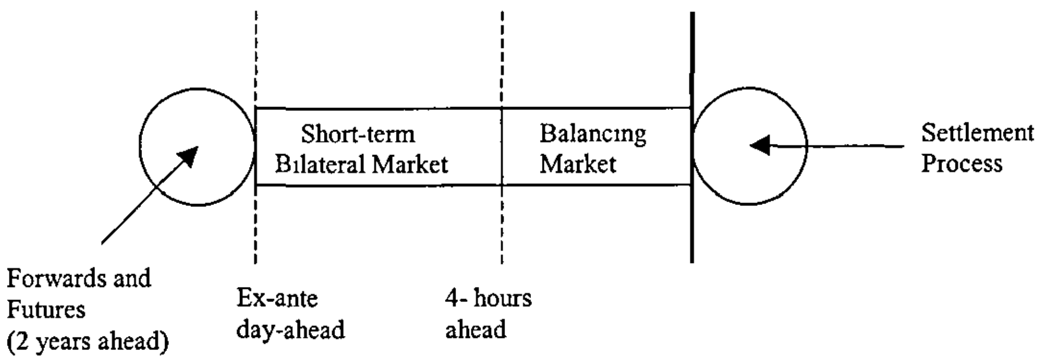

Figure 3.9.1 New trading arrangements

There would be forwards and futures markets where trades would take place bilaterally, via an exchange Reporting could be instantaneous via a screen-based system An options market would offer standard products. A short-term bilateral market organised by the market operator would operate continuously until the balancing market opens, 4 hours before real-time. It will have a screen-based system (displaying last accepted trade and outstanding offers and bids), with a clearinghouse under-writing the contracts. Offers and bids for standardised products are posted, modified and withdrawn until accepted, where they then become *firm*.

The balancing market is designed to enable the system operator to balance the system Generators, suppliers and customers submit location-specific offers and bids to the balancing market. Calculation of imbalances would need to take account of transmission losses If market participants did not balance their requirements, they are exposed to imbalance charges. These are calculated as the volume-weighted average of all trades accepted by the System Operator

The System Operator receives initial physical notification from participants by 15.00 on the day-ahead Transmission constraints that are likely to occur during the next day are estimated and the Balancing Market is used by the System Operator to alleviate constraints by accepting increments and decrements of output. The costs of constraints are recovered by comparing the costs of trades that took place, with an ex-post calculation of the costs of trades that would have been undertaken by the System Operator to balance the system in the absence of constraints Generators in the South would tend to withhold output in forwards, futures and short-term bilateral markets to secure greater volume in the Balancing Market Conversely those in the North have a greater incentive to increase output in those markets in the hope of having decrements accepted in the Balancing Market (see chapter five)

Governance arrangements are required to deliver change and respond to the needs of participants, without a blocking minority. Governance has been left to the market operator in both the forwards and futures, and short-term bilateral markets A balancing and settlement code is proposed that will govern the relationships of all participants in the Balancing Market. A panel consisting of stakeholders will have the role of oversight in the way rules are changed As the panel does not establish or implement policy, Ofgem argues that independents are not required. The Director General of Electricity Supply (DGES) would have the ability to block inappropriate rule changes. If this framework follows the success of the network code for gas, then rules are more likely to be changed quickly to respond to the need for change. This development would be welcomed

If financial and derivative markets developed, this would aid price discovery, and encourage new entry into the generating market However Ofgem have refused mandatory price reporting of forward contracts allowing instead for discretionary price reporting, believing that it will lead to product innovation. A concern that I have relates to new entrants who may not have confidence in the market as a result, because the forwards market may continue to remain thin. Mandatory price reporting would appear essential in the early stages to aid price discovery, particularly since there will no longer be a deep pool publishing price information on a daily basis, although it is not clear how this will happen.

3.10 Conclusion

The present trading arrangements could be developed into a two-sided deep pool Modifications to the firmness of bids and other rules of the pool could be made in time, provided an effective governance structure was in place. This would be a cheaper option than changing to completely new arrangements, and would aid in a proper cost-benefit analysis of a compulsory pool under market-orientated supply conditions

Ofgem (1999c) have indeed considered some modifications to the existing pool rules which may reduce the ability of *strategic behaviour* on the part of the major price-setting generators. The rise in system marginal price (SMP) since 1996/97 has run contrary to changes in generating fuel costs, which have fallen significantly for both coal and gas. Between 1993 and 1995, the new entry cost of CCGT generating plant fell by up to 25%, and "remains significantly below pool prices" (p.4)

A generator can structure bids so a high SMP is charged for the last few MW of its output, which in recent times have not reflected the cost of producing these few remaining MW of output For example a generator may have a bid of zero start-up and zero no-load and a zero first incremental bid However it may bid a very high second incremental bid, which is illustrated by the cost curve in figure 3.10 1 below

When the system elbows requires this relatively small increment of energy, SMP is set by the high incremental price, which is open to manipulation. Some generators have adopted a bid offer that resembles high no-load prices, combined with small differences between elbow points and variation of plant throughout the day (availability profiling). Thus generators have been able to raise SMP in off-peak periods. To combat this Ofgem did consider a simple bid, which offers one incremental price, and scraps no-load and start-up prices, which appears a sensible measure

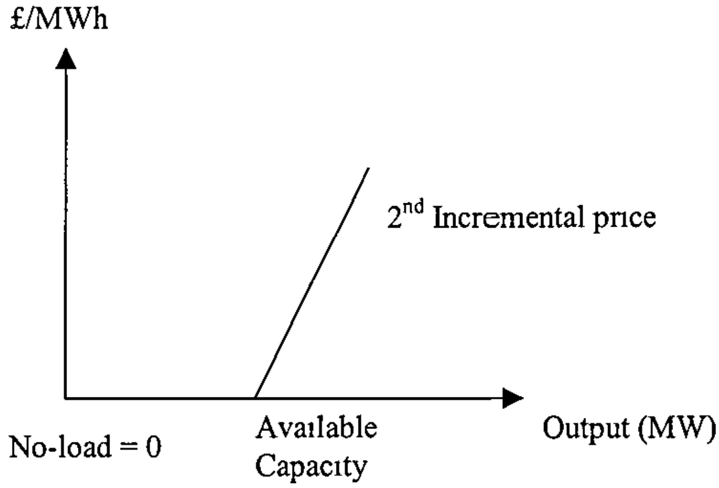

Figure 3.10.1 Incremental cost curve (Ofgem 1999c)

The problem of complex bids cited by financial markets as a reason for the illiquid nature of the forwards market would be addressed by this measure. It would be sensible to assess how pool prices behave under a simple bid system.

The other major concern is the widespread misuse of inflexibility markers. These markers were intended for plant that had to be dispatched for technical reasons. Consequently they did not contribute towards the derivation of system marginal price (SMP). Strategic behaviour is the key reason behind its increased use. Ofgem (1999c) argue that if this occurs "in conjunction with high second incremental bids, the likelihood of a price spike is increased" (p.9) Table 3 10.1 shows that flexible plant had diminished in 1998 compared to 1997, from 75% of output to 57% for the days considered in the study This leads to a reduction in price setting competition, and the further manipulation of pool prices.

	1997	1998
Flexible output	75	57
Totally inflexible output	23	39
Partially inflexible plant	2	4

Table 3.10.1 Inflexible Output

Removing all flexibility markers is therefore desirable, particularly since generators would still be able to submit a wide range of dynamic technical parameters for operation including ramping rates, minimum times for generation, minimum levels of stable generation and synchronisation time The combined removal of inflexibility markers and simple bidding would remove a large amount of complexity surrounding the pool, and improve transparency in the process. This may help to improve confidence in the existing deep pool, and lead to a high volume of innovative forwards and futures contracts. This will aid entry into the generating industry because as plant margin declines, the forward price should increase, thus signalling demand for new capacity up to two years ahead. Combined with a further divestment of price-setting plant, the modified Pool arrangements may herald an era of competitively based pool prices

The failure to conduct a proper cost-benefit analysis of switching to the new electricity trading arrangements based on a sealed first-price bid does not provide confidence Under this pay-as-bid system there is a trade-off between a high probability of being dispatched from a low bid and her surplus from being dispatched. The sealed first-price bid is more likely to be reflective of the winner's cost than an ascending uniform bid (resembles a second-price auction), and the prospect of tacit collusion is diminished A higher cost generator (lower value on being dispatched) will on the otherhand have a better opportunity of winning in a sealed first-price bid auction, so efficiency will decline relative to the ascending uniform bid. Ofgem however favour the sealed first-price bid auction because generators who have infra-marginal bids cannot use these costless threats to support the high price Nash equilibria in a current trading arrangements

Interestingly Ofgem (2000a) accept that there will still be opportunities for generators to exert market power. Very short term "balancing of the electricity market, coupled with inelasticities of demand, supply and the inability to store electricity can be expected to be an enduring characteristic of wholesale electricity markets close to real time" (p 30). This is why the regulator wants to introduce a *market abuse* condition, because there is potential for a *squeeze* in the market. A squeeze may occur when a player has significant influence over supply and uses this is conjunction with an on-exchange position to force other market users to settle with him at arbitrary and abnormal prices This work indicates that it is unlikely that the £1bn cost of switching is outweighed by the benefits derived from the new model

Chapter 4 Empirical study of Pool prices

4.1 Introduction

The previous chapter reviewed the literature on electricity trading arrangements One of the main conclusions of the chapter was that there was a concern that the proposals would end the advantages that currently exist with a compulsory liquid pool while failing to tackle the main problem of imperfect competition in the generating industry. OFFER view their proposals as a significant improvement, claiming that it will reduce the prices paid by suppliers and customers, for electricity generated by up to 10%. This figure does not appear to be substantiated in their reports except to say that the sequencing of contracts will aid in the decrease of prices.

If prices are assumed to be too high, then the nature of competition in the respective industry has to be reviewed. Chapter four endeavours to investigate pool prices since 1990 to contribute towards this debate If there is insufficient competition, then the argument follows that price setting generators should be required to divest further capacity, until the supply function schedule converges towards the competitive horizon, as illustrated by figure 3 5.1 in chapter 3

Helm and Powell (1992) analysed pool prices from the time of Vesting (April 1990) until August 1991 The centrepiece of the analysis consisted of an event study, because the objective of the research was to ascertain whether the pool purchase price was higher after the first Vesting contract ended on 22nd March 1991. *An event will be defined as public information that may impact upon the pool purchase price, such as contracts and regulatory statements and proposals*

The null hypothesis tested by Helm and Powell (1992) is that there would be no effect on pool prices after the first Vesting contracts expired. Results of the study concluded that the model under-predicted the pool purchase price after rejecting the null hypothesis. This is substantiated by the fact that regional electricity companies reduced the amount of electricity hedged after the first contracts ended Thereafter an incentive was provided for generators to increase profits by raising the pool purchase price. The previous chapter outlined a model by Powell (1993) based on financial market theory, and showed that when a generator's output is fully covered by contracts, revenue would not be dependent on pool prices RECs benefited from a fixed price in the franchise market, while generators were able to hedge the cost of investments. Contracts may lead to collusive behaviour by generators, particularly since the pool operates in a repeated game environment. This is why a study of pool prices in conjunction with contracts is necessary to understand the movement in the pool purchase price.

4.2 Choosing the observations underlying the forecast

This study builds on the work by Helm and Powell (1992) by making forecasts of prices using traditional price-demand analysis Half hourly pool purchase prices $[P]$ and demand forecasts for the next day $[DF]$ were obtained from Midlands Electricity. Electricity prices were deflated by the March 1998 RPI price index Helm and Powell (1992) used average daily data for their analysis of pool prices. However a simple daily average will smooth out the effects of dominant generators in the non-baseload market This is the market that the study is concentrating on given that there appears to be a strong contestable market in baseload generation (MMC 1996 report) Therefore half-hourly data is used to focus on the time periods where price-setting generators who have significant infra-marginal capacity, are able to tacitly collude and manipulate pool prices.

One of the problems with an event study is that a large time frame window may include more than one event for deriving a forecast of electricity prices The underlying influences of prices are therefore difficult to ascertain Therefore it is important that the time frame window within which the context of the study is based is not too large. Therefore it is proposed to employ a time frame window of sixty days to avoid more than one major event influencing the pool price in most cases It is also important that events are not too closely packed together, because there is the risk of significant differences arising following a regulatory statement, a concern noted by Dnes and Seaton (1995a and 1995b) when testing for abnormal returns and regulatory capture in the electricity distribution sector and British Telecom.

A load profile is defined as the pattern of electricity demand for a customer or group of customers over a period of time. Daily demand is summed over the forty-eight half-hours and a profile coefficient is calculated, defining the proportion of electricity consumed in each of the half-hours Figure 4 2 1 below provides a plot of an average weekday load profile between April 1997 and March 1998.

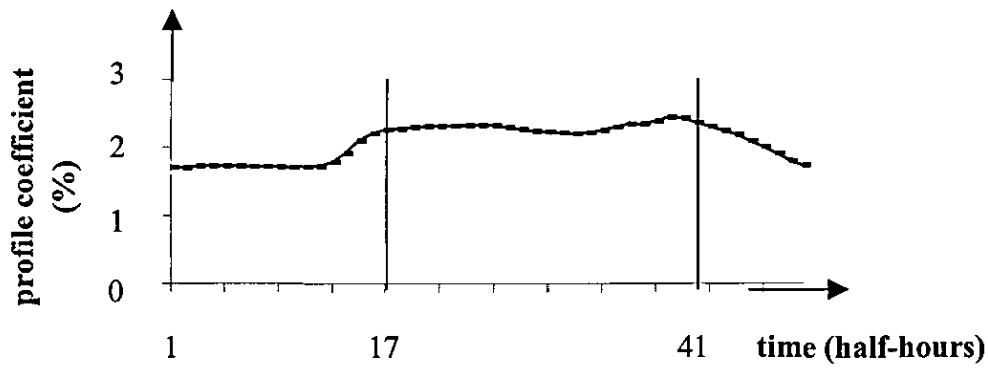

Figure 4.2.1 Average Load profile

I have inferred from figure 4 2 1 that the typical non-baseload market is covered by the time period between half-hour 17 and half-hour 40 (8am to 8pm) which provides 24 observations for each day used in the analysis. Load profiles for weekends and public holidays differ from a typical weekday, and so there is a danger that using the same time-period for non-weekday observations would lead to competitive half-hours being included in the analysis Since the study is concerned about imperfect competition in the non-baseload market, it was decided to base the regression models exclusively on weekdays (excluding public holidays). For a thirty-day month with four weekends, twenty-two days would be used in the analysis either side of the event, leading to a typical sample size of 1056 observations

Assume time $[T]$ represents the day when the event takes place. The regression constructed for forecasting electricity prices for non-contract events will be based on the following data:

$$P_T, P_{T-1}, \ldots, P_{T-N} \tag{4 2 1}$$

$$DF_T, DF_{T-1}, \ldots, DF_{T-N} \tag{4 2 2}$$

where N represents the number of weekdays included in the forecast prior to the event on day $[T]$ taking place The pool is an ex-ante market, so the price of electricity for each half-hour on day $[T]$ is calculated a day-ahead. However when contracts are defined as an event, the pool price on the day of the event will reflect the new environment. Therefore data in day $[T]$ are used to assess the accuracy of the prediction, and extrapolate whether the forecast is significantly different from the published pool purchase price.

4.3 Events to be studied

Dates	Events
22/03/91	1st set of Vesting contracts expire
01/04/92	New contracts come into force
22/10/92	DG examines plant closure of NP / PG
31/03/93	2nd set of Vesting contracts expire
01/04/96	New contracts come into force
01/04/97	New contracts come into force
08/05/97	3rd Consultation paper – support for max price limits
30/06/97	DTI announces review of utilities regulation
15/10/97	DG investigates 3 plant closures by NP and PG

Table 4.3.1 Events to be modelled

This section seeks to justify the inclusion of the events listed in table 4.3.1 for this study. Following the signing of the brokered government contracts at Vesting in 1990, over 95% of generating output were covered by contracts in the first year Helm and Powell (1992) studied the break-up of the first set of Vesting contracts, proving that incumbent generators had adopted a low price strategy to prevent new generators entering the market and increasing the competitive environment. This event was used as a control study

The second Vesting contracts expired on the 31st March 1993, so this seemed an appropriate event to examine whether similar conclusions could be drawn with the first Vesting contracts. Annual contracts in general are a useful test, because they may enlighten the reader on the type of strategy embarked upon during contract negotiations Therefore new contracts for 1992/93, 1996/97, and 1997/98 are defined as events in the study.

However I have omitted the contracts covering 1994/95, and 1995/96, because as part of the agreement brokered between the regulator, National Power and Powergen in late 1993, pool price caps were imposed for those two years. Divestment of plant and pool price caps were the quid-pro-quo for preventing the director general of electricity regulation from referring the two generators to the MMC. Consequently time-weighted and demand-weighted average pool price ceilings incentivised the two generators to maximise revenue up to this level Price distortions will result leading to potentially significant fluctuations in prices as the generators seek to meet the criteria set out by the regulator. Therefore it was deemed appropriate to exclude these two years from the analysis.

A Labour government was elected in the UK in May 1997. Policies between the previous and new government were similar in many areas, but there were some major differences, especially towards utility regulation. Consequently the possibility arose that the dominant generators may have reviewed their strategy following the election of the new government An event study is used to reflect any possible changes in their behaviour in the first six months following the election, since there were significant announcements directed towards the electricity industry that may have caused the generators to pause and reflect

In May 1997 the regulator published a third consultation paper that contained support for the introduction of maximum price limits for customers supplied by regulated supply businesses. Although the market was in the process of being liberalised, regulation is there to protect those customers who in the short-term are unable to benefit from competition. Suppliers will no longer be able to pass on the cost of purchasing electricity under these new proposals The new mechanism created incentives for suppliers to purchase efficiently, and so generators may take the view to maximise profits while they can. Of equal importance was the new government's proposed windfall tax on the privatised utilities, including National Power and

Powergen. Therefore the event would help to explain whether electricity prices have moved in an upward direction to help finance the cost of this tax

The Department for Trade and Industry (DTI) announced a review of utility regulation in June 1997 In opposition, the Labour party floated the idea of sliding scale-regulation, so the benefits of efficiency could be passed onto customers much quicker than the current arrangements, which have a price review every four or five years. If the generators feared that the review might lead to an investigation in their market structure, they may hedge this risk by strategically lowering the pool price. Alternatively the generators may perceive the threat of investigation as inevitable, and hence adopt a strategy that maximises short-run profits A study into this event would help to clarify these propositions.

During 1997/98, industrial users, consumers, suppliers, and traders were concerned about the level of system marginal price (SMP) In October 1997, the government responded to those concerns by announcing a review of the electricity trading arrangements (ETA) discussed in chapter 3. This coincided with the regulator announcing an investigation into the closure of three plants by National Power and Powergen on the previous day These events were combined because they had the potential to undermine the profitability of the generators in the long-term if proposals included an overhaul in the structure of the generating industry

4.4 Regression Strategies

For this study it is important to test whether there is an underlying relationship between the pool purchase price $[P_t]$ and demand forecast $[DF_t]$. Consider the following model·

$$\ln(P_t) = \alpha + \beta \ln(DF_t) + \varepsilon_t \qquad (4\ 4\ 1)$$

The assumptions of a classical regression model require that both $\ln(P_t)$ and $\ln(DF_t)$ observations are stationary and errors have a zero mean and finite variance. A series is stationary if the mean, variance, and autocorrelations can be approximated by long-time averages based on a single set of observations. Monte Carlo studies have shown that there is a high probability of the model appearing to have a significant relationship even though the true value of $[\beta]$ is zero Granger and Newbold (1974) show that a spurious regression as defined above will occur in the presence of non-stationary variables. This is where two variables are independent of each other, but there is a high degree of autocorrelation as demonstrated by equation 4 4 2.

$$\varepsilon_t = e_{\ln(P_t)} - \alpha - \beta e_{\ln(DF_t)} \tag{4 4 2}$$

where independent random walks have been assumed i.e. $\ln(P_t) = a_1 \ln(P_{t-1}) + e_{\ln(P_t)}$ and $\ln(DF_t) = a_2 \ln(DF_{t-1}) + e_{\ln(DF_t)}$. Dickey-Fuller tests could be used to test for the presence of a unit root ($a_1 = 1$ and $a_2 = 1$) If for example the components of equation 4.4.1 each contain unit roots, but a first difference reject the null hypothesis of the presence of unit roots, $\ln(P_t)$ and $\ln(DF_t)$ are classified as $I(1)$ stationary. The study however has used autoregressive distributed lag (ARDL) techniques to test for the existence of a cointegrating relationship between $\ln(P_t)$ and $\ln(DF_t)$. The advantage of using this estimation method is that it can be "applied irrespective of whether the regressors are $I(0)$ or $I(1)$", so it eliminates the problem of testing for stationarity (Pesaran, and Pesaran 1997, p 303)

The procedure consists of two stages. The first stage tests for existence of a long run relationship between price $[P_t]$ and demand $[DF_t]$. If the computed F-statistic falls outside a critical band, a long-run relationship is assumed to exist Table 4.4.1 below provides the critical value bounds of the F-statistic with an intercept and no trend for the model that regresses $\ln(P_t)$ onto $\ln(DF_t)$

95% confidence	95% confidence
I(0)	I(1)
4.934	5.764

Table 4.4.1 Critical value bounds

A maximum of four lags are applied to each log-log regression constructed The constant elasticity model is used because the log-log form gives a better fit than the linear model It is also useful when dealing with a large sample size vulnerable to price spikes to consider the change in price for a given percentage change in demand, regardless of the absolute level of demand. Therefore I proceeded with this method. The ARDL model is defined as:

$$\beta(L)\ln(P_t) = \alpha + \gamma(L)\ln(DF_t) + u_t \qquad (4\,4\,3)$$

where $\beta(L) = 1 - \beta_1 L - \beta_2 L^2 - \beta_3 L^3 - \beta_4 L^4$

$$\gamma(L) = \gamma_0 + \gamma_1 L + \gamma_2 L^2 + \gamma_3 L^3 + \gamma_4 L^4$$

and L is a lag operator such that $L\ln(P_t) = \ln(P_{t-1})$ For a variable defined as y_t, $y_t = \Delta y_t + y_{t-1}$, and $y_{t-1} = y_{t-1} - \sum_{j=1}^{s-1} \Delta y_{t-j}$, $s = 1,2,3,4$ Applying this general result to equation 4.4.3, the error correction model that tests for cointegration is

$$\Delta\ln(P_t) = \alpha + \sum_{i=1}^{4} \beta_i \Delta\ln(P_{t-i}) + \sum_{i=1}^{4} \gamma_i \Delta\ln(DF_{t-i}) + \delta_1 \ln(P_{t-1}) + \delta_2 \ln(DF_{t-1}) + u_t \qquad (4\,4.4)$$

If the computed F-statistic is within the critical value band at the 95% level of significance, we can not say that we have stationarity of residuals Unit root tests would then be carried out to test whether the variables are $I(0)$ or $I(1)$ stationary.

$$H_0 . \delta_1 = 0 \qquad (4\,4.5)$$

Rejection of the null hypothesis at the 95% level of significance means that we can reject the null hypothesis of no long-run relationship between $\ln(PPP_t)$ and $\ln(DF_t)$

$$H_1 \;\; \delta_1 \neq 0 \qquad (4.4\,6)$$

The significance of the lagged level variables explaining $\partial \ln(DF_t)$ is then considered by adjusting the error correction model as represented by equation 4.4.7.

$$\partial \ln(DF_t) = \alpha + \sum_{i=1}^{4} \beta_i \partial \ln(P_{t-i}) + \sum_{i=1}^{4} \gamma_i \partial \ln(DF_{t-i}) + \delta_1 \ln(P_{t-1}) + \delta_2 \ln(DF_{t-1}) + u_t \quad (4\ 4\ 7)$$

The null hypothesis is now stated as:

$$H_0 : \delta_2 = 0 \quad (4\ 4.8)$$

If the null hypothesis is rejected then this confirms that a long-run relationship exists between $\ln(P_t)$ and $\ln(DF_t)$ The statistical relationship does not in general determine the direction of causality The research undertaken however has adopted the approach of $\ln(DF_t)$ explaining $\ln(P_t)$ since the pool auction will select least-cost plant until supply meets expected demand

The second stage estimates the coefficients of the long-run relationship. Forecasts of pool prices after the event has taken place are made from equation 4.4.3. A test of prediction is used to consider whether any change in the pool purchase price is significant The direction of change may be predicted following an event arising, and so a one-tailed test was employed in the analysis.

$$\ln(P_t) = \alpha + \gamma \ln(DF_t) \quad (4.4.9)$$

$$\ln(P_t) = \alpha + \gamma \ln(DF_t) + \mathrm{S}\delta \quad (4.4.10)$$

Equation 4 4 9 represents the first sample (prior to event), while equation 4 4 10 is used to formulate the prediction (where S represents the matrix of dummy variables, one dummy for each observation in the second period) The null hypothesis of the predictive failure test is

H_0 · event has no effect on the pool purchase price (4.4.11)

This implies that the underlying estimated relationship from the forecast predicts well Intuitively, the strategy of the generators in the pool has remained unchanged Rejection of the null hypothesis means

H_1 event has a significant effect on the pool purchase price (4 4 12)

Therefore the underlying estimated relationship does not predict well One interpretation is that it provides evidence of strategic behaviour by the generators in the pool following an event occurring For example suppose an event is defined as the regulator contemplating a referral of the generators to the MMC The generators might be expected to lower their bids into the pool, so the hypothesis in equation 4.4.11 is rejected if pool prices are significantly lower than predicted Evidence of the generators manipulating pool prices in an attempt to head off an investigation by the competition authorities is implied by this conclusion

The standard econometric procedure of introducing lags to equation 4 4 3 is applied in the event of serial correlation A plot of the residuals is used to infer potential outliers When a dummy variable is applied to a specific observation, it is equivalent to deleting that observation. The coefficient on the dummy variable measures the forecast error, so if the null hypothesis is rejected at the 5% level of significance, implying that the observation represents an outlier

If the diagnostic tests indicate the presence of heteroscedasticity, weighted-least squares $[WLS]$ is used to produce a constant variance across the number of observations. Feldstein (1967) used the likelihood ratio test for hospital cost regressions to resolve heteroscedasticity because the number of observations (177) was large A likelihood ratio test is a general large-sample test based on the maximum likelihood method. The first stage is to divide the residuals estimated from the *ARDL* regression into $[k=4]$ equal groups with $[n_i]$ observations in the *ith* group. Residuals are ordered in ascending order of $\ln(DF_t)$. However when the ordering is not satisfactory (constant variance among the four groups when the diagnostic tests rejected the null hypothesis of homoscedasticity) the ordering of the residuals is based on $\ln(P_t)$. From this process $[\lambda]$ is derived as:

$$\lambda = \left[\prod_{i=1}^{k}(\hat{\sigma}_i)^{ni}\right] \Big/ \hat{\sigma}^n \qquad (4.4\ 13)$$

where $\left[\hat{\sigma}^n\right]$ is the estimate of the standard deviation of the total sample set, and $\left[\hat{\sigma}_i^{\ ni}\right]$ represents the estimate of the standard deviation of the sub-set $[i]$. The likelihood ratio test consists of calculating $[-2\log_e \lambda]$ and comparing its value to the 1% or 5% significance point for the χ^2-distribution with $(k-1)$ degrees of freedom. The hypothesis are stated as:

H_0 · no significant difference in the variance of errors between the 4 groups (4 4.14)

H_1 . significant difference in the variance of errors between the 4 groups (4 4.15)

If the null hypothesis of homoscedasticity is rejected as the diagnostic tests indicate, the observations are weighted in proportion to $1/\hat{\sigma}_i$. Feldstein (1967) normalised the weights to make their average equal to unity. The overall effect of this strategy is to produce a constant variance between the groups Equation 4.4.3 is then re-estimated using these weights.

One of the econometric problems that has persisted throughout the study is non-normality As the frequency of data increases the probability of random observations increases. Half-hourly pool prices are likely to fall into this category because there is a high degree of volatility in these prices. This may be influenced by a large number of independent variables, which have not been explicitly introduced into the regression. On the assumption that no one constituent of the residuals dominates, the requirements of the central limit theorem are met, and the assumption of normally distributed errors may be justified

When time-series analysis is performed, the error term in OLS may be unconditionally homoscedastic, but there may be an alternative non-linear estimator that is more efficient. Autoregressive conditional heteroscedasticity models (ARCH) are designed to model and forecast conditional variances. A prediction of the pool price variance for period (t) is made by forming a weighted average of a long-term average (h), the forecasted variance from the previous period $(\sigma^2{}_{t-1})$, and information about the volatility observed in the previous period $\varepsilon^2{}_{t-1}$ as defined by equation 4 4.16.

$$\sigma_t^2 = h + \mu\varepsilon_{t-1}^2 + \rho\sigma^2{}_{t-1} \qquad (4.4.16)$$

Estimates for μ and ρ are made but they must sum to no greater than unity. However for all the events the process did not converge (using an iterative process), even after adjusting the estimates of μ and ρ

4.5 Results of the nine events

Table 4.5.1 reviews the results of the study for nine of the events. There are two events where no structural change in the pool purchase price is recorded, being when new contracts come into operation in 1992 and 1997. Therefore the strategy of the generators has not changed following the introduction of the new contracts. The remaining seven events are discussed below, where there is evidence of a structural change in the pool purchase price after the event has taken place.

Event	Structural change in prices
1st set of Vesting contracts expire	Yes
New contracts come into force in 1992	No
DG examines plant closure of NP / PG	Yes
2nd set of Vesting contracts expire	Yes
New contracts come into force 1996	Yes
New contracts come into force 1997	No
3rd Consultation paper by OFFER/new government	Yes
DTI announces review of regulation	Yes
DG investigates 3 plant closures	Yes

Table 4.5.1 Review of results (see appendix A for diagnostic tables)

(a) First Vesting Contracts expire

After resolving the problems of serial correlation and outliers using the strategy outlined in the previous section, a cointegrating relationship between the pool purchase price $[P_t]$ and demand forecast $[DF_t]$ is found when equation 4.51 is modelled:

$$\beta(L,2)\ln(P_t) = \alpha + \gamma(L,3)\ln(DF_t) \tag{4.5.1}$$

Figure 4.5.1 below displays the forecast of pool prices following the break-up of the first Vesting contracts in 1991. This suggests that on average the model under-predicted pool prices after the first Vesting contracts ended in March 1991, given that the mean predicted error is $[+0.096]$. A test for accuracy of predictions rejects the null hypothesis that the event has no effect on pool prices, $\chi^2(432) = 252.92[0.000]$, at the 5% level of significance.

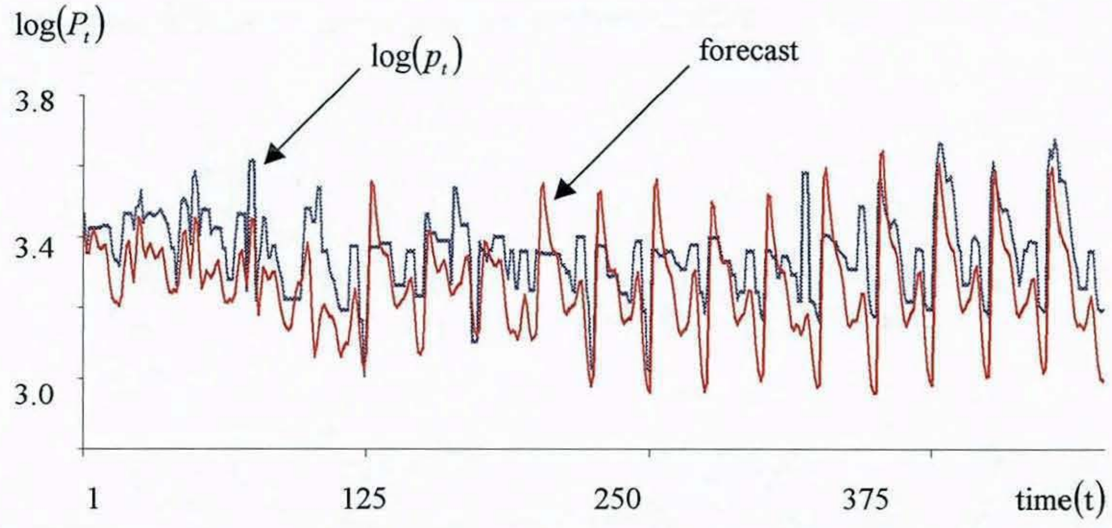

Figure 4.5.1 Forecast of $\log(P_t)$

Table 4.5.2 below provides details of the contraction in output covered by contract-for-differences (CfDs) by National Power $[NP]$ and Powergen $[PG]$ in 1990/91 and 1991/92, obtained from Green (1999). This shows that contract cover for generated output fell from over 100% to 87% for National Power and from 94% to 77% for Powergen. Therefore optimal hedging theory suggests generators were then in a position to significantly increase pool prices. A fully contracted output cover will move pool prices in the direction of a competitive outcome because pool prices are independent of the total revenue that a generator can accrue.

Year	NP Output	NP CfDs	PG Output	PG CfDs
1990/91	121.8	122.5	76.1	71.2
1991/92	117.1	102.0	75.2	57.6

Table 4.5.2 Contract and Pool sales (TWh) in 1990/91 and 1991/92

Strategic behaviour was achieved in two ways according to table 4.5.3 below. Although demand for electricity fell from 38,412MWh to 35,826MWh after the event, surplus capacity declined from 15,645MWh to 12,632MWh. The strategic behaviour that lies behind a reduction in availability of plant is for capacity payments (CP) to increase. Capacity payments on average increased from zero to £0.65/MWh. Price-setting generators also increased system marginal price from £27.93/MWh to £28.27/MWh. In a competitive environment the expectation would be of lower pool prices following a decrease in demand. This substantiates the findings made by Helm and Powell (1992) who found that dominant generators were able to take advantage of a reduction in hedged contracts by systematically increasing the pool purchase price.

	P	$\sigma(P)$	SMP	$\sigma(SMP)$	CP	$AVAIL$	DF
Ex-ante	27.93	3.51	27.93	3.51	0.00	54057	38412
Ex-post	28.91	3.31	28.27	2.58	0.65	48459	35826

Table 4.5.3 Average price and demand data between 8am and 8pm

(b) Director General investigates plant closures in 1992

The best regression used for forecasting the pool purchase price is:

$$\beta(L,3)\ln(P_t) = \alpha + \gamma(L,3)\ln(DF_t) \qquad (4.5.2)$$

A test for the accuracy of predictions rejected the null hypothesis of no structural change at the 5% level of significance, $\chi^2(500) = 2157.6[0.000]$, following this announcement by the regulator. Figure 4.5.2 provides evidence of fluctuating prices. A conclusion that can be drawn is that the model appears to have difficulty predicting pool prices. In a competitive environment, financial traders are confident of predicting prices into the future. However the results of this study do not justify any confidence in the competitive model in predicting pool prices, and so this represents a form of strategic behaviour. A lower level of contracting in 1991/92 (table 4.5.2) has precipitated this outcome. Price spikes increase the risk for suppliers, and hence the premium paid for contracts in the next contract round.

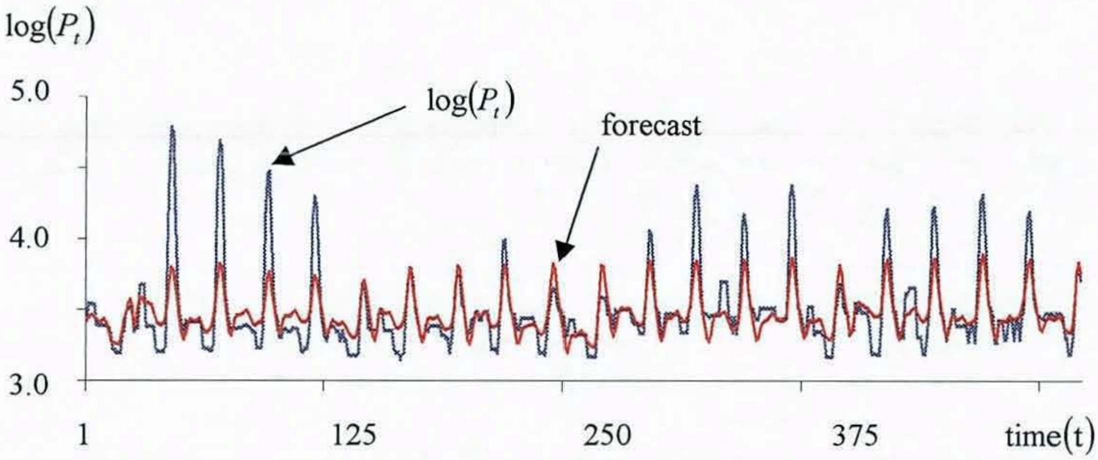

Figure 4.5.2 Forecast of $\log(P_t)$

When pool prices are compared, table 4.5.4 shows there has been a marked increase in fluctuations following the announcement by the regulator. Increases in capacity payments explain most of the rise in pool prices.

	P	$\sigma(P)$	SMP	$\sigma(SMP)$	CP	$AVAIL$	DF
Ex-ante	30.95	3.43	30.69	3.15	0.26	48916	36065
Ex-post	34.19	12.74	31.07	4.83	3.12	52448	39131

Table 4.5.4 Average price and demand data

The probability mechanism, and hence the capacity payment are vulnerable to significant variations, even with small changes in demand. Electricity data for a day in October 1992 is used to illustrate this phenomenon (table 4.5.5). Between 16:30 and 18:30, there was a significant increase in capacity payments following a decline in surplus capacity. The regulator eventually changed the calculation of the capacity payment so events of the previous seven days would have to be taken into account when deriving the loss of load probability, so this type of strategic behaviour would be mitigated.

An interpretation of the results is that the dominant generators did not believe that a radical change in the structure of the generating industry was credible. If they thought an MMC investigation was likely after the conclusion of the investigation into plant closure, rational expectations would suggest benign or lower than expected pool prices to demonstrate adequate competition in the industry. An alternative proposition is that unpredictable pool prices are caused by the willingness of the price-setting generators to use market power for maximising revenues before the regulator intervenes and curbs their power.

Time	*AVAIL*	*DF*	*SURPLUS*	*SMP*	*CP*	*P*
1500-1530	51065	37698	13367	24.56	0.09	24.65
1530-1600	51113	38520	12593	24.56	1.05	25.61
1600-1630	51126	40136	10990	39.97	10.86	50.83
1630-1700	51126	42050	9076	31.80	53.35	85.15
1700-1730	51126	43500	7626	49.58	69.71	119.29
1730-1800	51139	42612	8527	49.58	65.61	115.20
1800-1830	50961	41542	9419	39.97	24.84	64.82
1830-1900	50388	40380	10008	31.09	7.39	38.48
1900-1930	50412	39258	11154	31.09	1.66	32.75
1930-2000	50321	37735	12586	29.58	0.27	29.85

Table 4.5.5 Electricity data for 26th October 1992 (1998 prices)

(c) Break-up of second set of Vesting contracts

After taking account of two major outliers, a forecast of pool prices is based on the regression:

$$\beta(L,2)\ln(P_t) = \alpha + \gamma(L,2)\ln(DF_t) \tag{4.5.3}$$

with a mean predicted error for the forecast of $[0.208]$. The null hypothesis of no structural change in pool prices was rejected at the 5% level of significance, $\chi^2(480) = 782.8450[0.000]$. Therefore we can infer that on average pool prices were significantly higher than predicted from equation 4.5.3. Figure 4.5.3 below clearly demonstrates that for most of the observations the model under-predicts $\log(P_t)$.

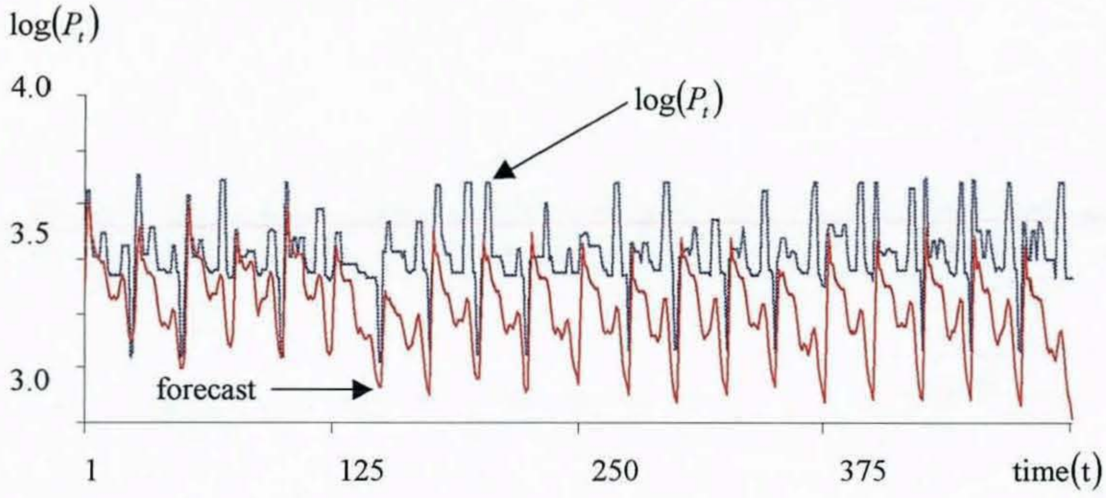

Figure 4.5.3 Forecast of $\log(P_t)$

Table 4.5.6 reveals that demand fell from 37,898MWh to 34,534MWh, while surplus capacity rose slightly, so the higher than expected pool purchase price emerges as a consequence of the dominant generators bidding higher into the day-ahead auction.

	P	$\sigma(P)$	SMP	$\sigma(SMP)$	CP	$AVAIL$	DF
Ex-ante	29.21	3.86	28.96	3.34	0.25	53654	37898
Ex-post	30.91	4.01	30.87	3.99	0.04	50593	34534

Table 4.5.6 Average price and demand data

Figures from the Digest of United Kingdom Energy Statistics (1997) show that the average price of coal purchased by the major UK power producers fell from 0.611p/kWh (current terms) in 1992/93 to 0.528p/kWh in 1993/94. As coal prices were also falling in real terms, these reductions might have been expected to be passed onto the customer.

After the second Vesting Contracts expired, there was political pressure on the government to provide support for the beleaguered coal industry. This led to a new five-year back-to-back contract (for a smaller quantity of coal) brokered by the government. The level of output hedged by Recs with National Power declined considerably between 1992/93 and 1993/94, while less than 75% of Powergen's output was hedged by Recs in 1993/94 as table 4.5.7 shows. Hence there was plenty of scope for generators to manipulate pool prices because of the decline in contracted output.

Year	NP Output	NP CfDs	PG Output	PG CfDs
1992/93	108.6	108.2	73.5	55.8
1993/94	94.6	79.6	70.2	51.7

Table 4.5.7 Contract and Pool sales (TWh) in 1992/93 and 1993/94

(d) New contracts come into force in 1996/97

A forecast of pool prices is based on the weighted-least squares regression:

$$w\beta(L,2)\ln(P_t) = w\alpha + w\gamma(L,3)\ln(DF_t) \tag{4.5.4}$$

The model rejects the null hypothesis of adequate predictions $\chi^2(1) = 0.14832[0.700]$ at the 5% level of significance. Evidence of a structural change in pool prices after the 1996/97 contracts come into operation is provided by this result. Figure 4.5.4 below shows the weighted-least squares regression leading up to the event.

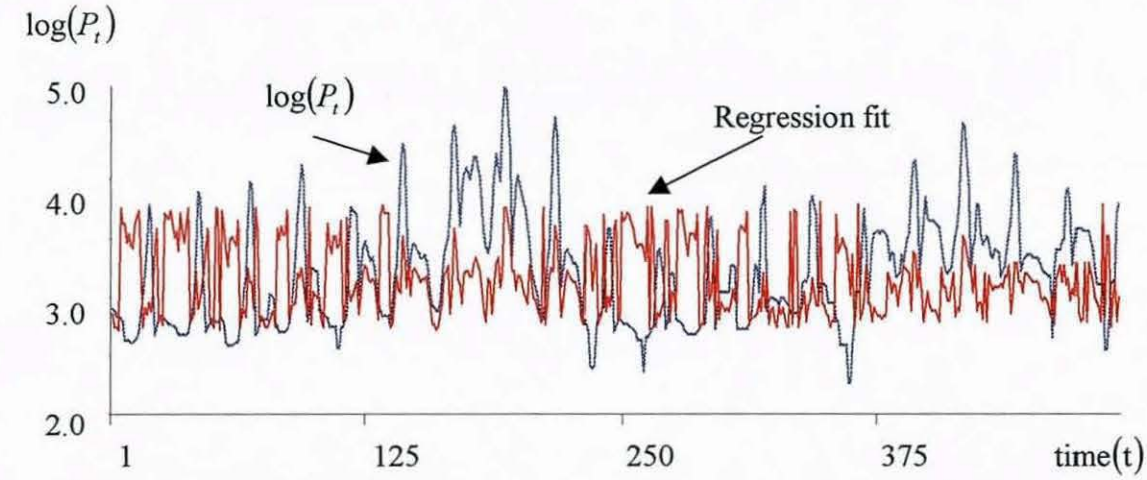

Figure 4.5.4 Goodness of fit

The unpredictability of pool prices prior to the event is likely to be due to the pool price caps that were imposed between 1994/95 and 1995/96. Strategic behaviour in March would revolve around maximising revenue while ensuring that average time-weighted and demand-weighted pool prices did not exceed the ceiling imposed by the regulator for the year.

Figure 4.5.5 shows an improvement in the predictability of the model following the removal of the pool price caps on 1st April 1996.

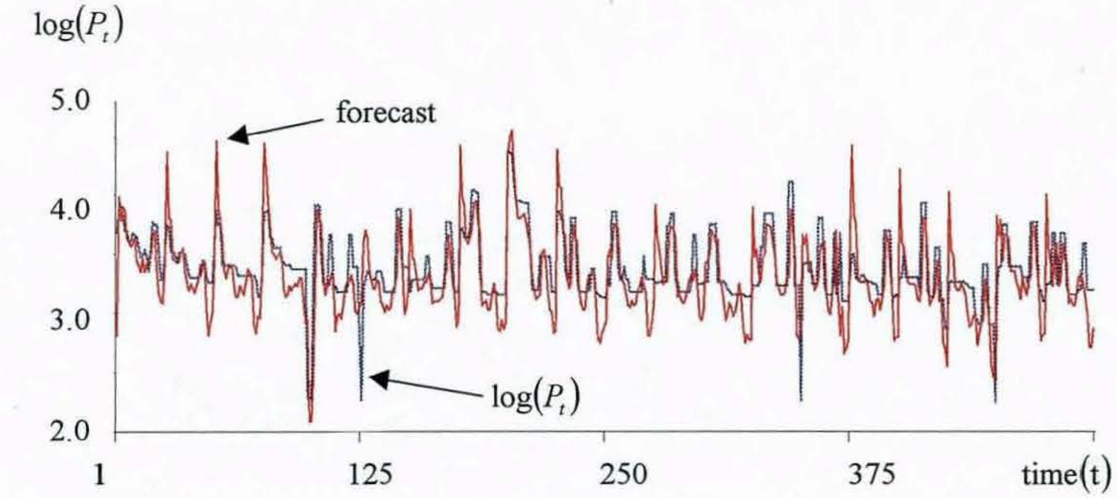

Figure 4.5.5 Forecast of $\log(P_t)$

Tighter regulation may explain the improvement in the predictability of the model. A statement from the regulator on whether the two generators adhered to the price caps concluded that

"The two generators were able significantly to increase the differential between peak and off-peak prices. They were also able to reduce average SMP by 70 per cent over the course of two weeks in January 1995, and to hold it at an unprecedentedly low level for two months. To some extent these bidding prices were geared to meeting the Undertaking. Nevertheless, they constitute further clear evidence of the market power of the two major generators" (Offer June 1996 press release).

The regulator has indicated a willingness to continue to monitor pool prices, which in due course could lead to further changes in the structure of the industry if evidence of further market dominance was found. The experience of monitoring pool prices over the last two years makes it easier for the regulator to track changes in pool prices. Generators may have accepted that the position taken by Offer was credible particularly in the light of a general election approaching in the near future.

When the new contracts came into operating in April 1996, average SMP was over £10/MWh higher as table 4.5.8 shows below though it was artificially low prior to this event. Furthermore capacity payments were approaching £8/MWh on average before the pool price caps ended, but fell to negligible levels after 31st March 1996. British summer time (BST) in part will explain the reduction in capacity payments, as lower demand will increase spare capacity in the system. Hence the probability of shedding load decreases. Moreover the variability of capacity payments prior to April 1996 suggests that generators may have used plant availability as a strategic device for meeting the price cap ceiling, therefore producing an inferior model of pool prices prior to the event.

	P	$\sigma(P)$	SMP	$\sigma(SMP)$	CP	$\sigma(CP)$	$AVAIL$	DF
Ex-ante	27.99	16.06	20.02	7.13	7.97	13.44	51847	40794
Ex-post	30.77	9.64	30.47	9.35	0.30	9.64	49502	36718

Table 4.5.8 Average price and demand data

(e) 3rd consultation document into price restraints after 1998

A forecast of pool prices is based on the regression:

$$\beta(L,1)\ln(P_t) = \alpha + \gamma(L,3)\ln(DF_t) \tag{4.5.5}$$

The predictive failure test rejects the null hypothesis of no structural change at the 5% level of significance, $\chi^2(480) = 645.89[0.000]$. Therefore one can surmise that the combination of a new government committed to a windfall tax and the regulators support for maximum price restraints have coincided with higher than forecasted pool prices according to figure 4.5.6. Which of these two events seems the most likely to explain this outcome? The result appears to reinforce the view that a windfall tax is not a painless option. Given the dominance of the non-baseload market by National Power and Powergen, it would not be sensible for them not to systematically raise the level of their bids into the day-ahead auction as a means of financing their tax liabilities. This method would protect their profits and shareholder value, while forcing customers to pay the tax indirectly through higher electricity prices. If the generating industry were competitive in the non-baseload market, it would be more difficult for National Power and Powergen to raise prices, because their market share of this important revenue market would be hit considerably.

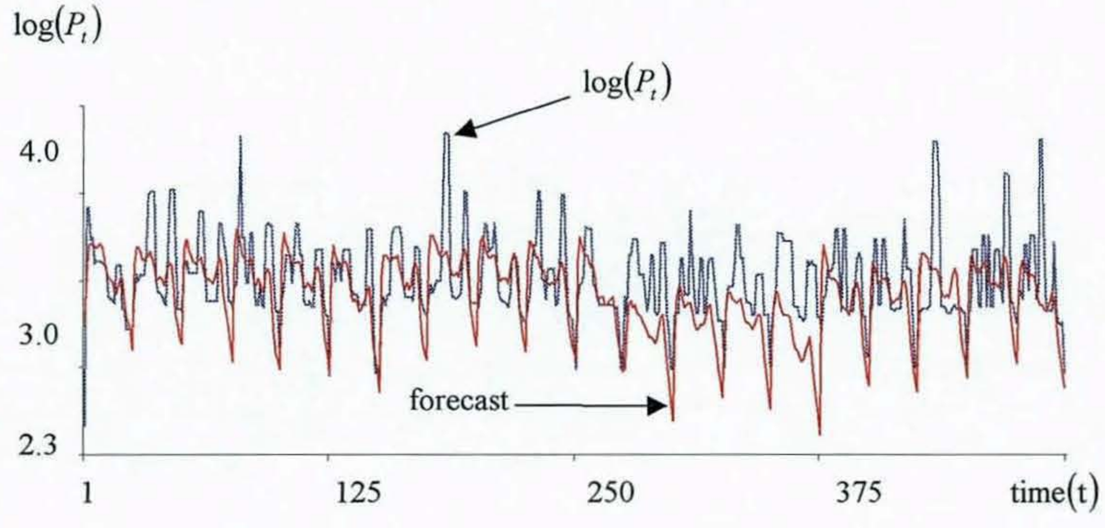

Figure 4.5.6 Forecast of $\log(P_t)$

Table 4.5.9 shows that after 8th May 1997, average demand fell by nearly 2000MWh, leading to an average reduction in the pool purchase price of over £1.20/MWh. Nevertheless, although pool prices responded in the right direction to a decline in demand, the forecast and predictive failure test implies that even lower pool prices would have been expected if the strategy adopted prior to the event continued thereafter.

	P	$\sigma(P)$	SMP	$\sigma(SMP)$	CP	$AVAIL$	DF
Ex-ante	29.48	8.07	29.27	7.93	0.21	51266	36348
Ex-post	28.26	7.72	27.99	7.55	0.27	48587	34665

Table 4.5.9 Average price and demand data

(f) DTI review of regulation

The regression that is preferred for this event is:

$$\beta(L,2)\ln(P_t) = \alpha + \gamma(L,1)\ln(DF_t) \tag{4.5.6}$$

The null hypothesis is that the generators would constrain their market power to prevent the review leading to a restructuring of the generating industry. Hence we would expect the forecast to overestimate pool prices.

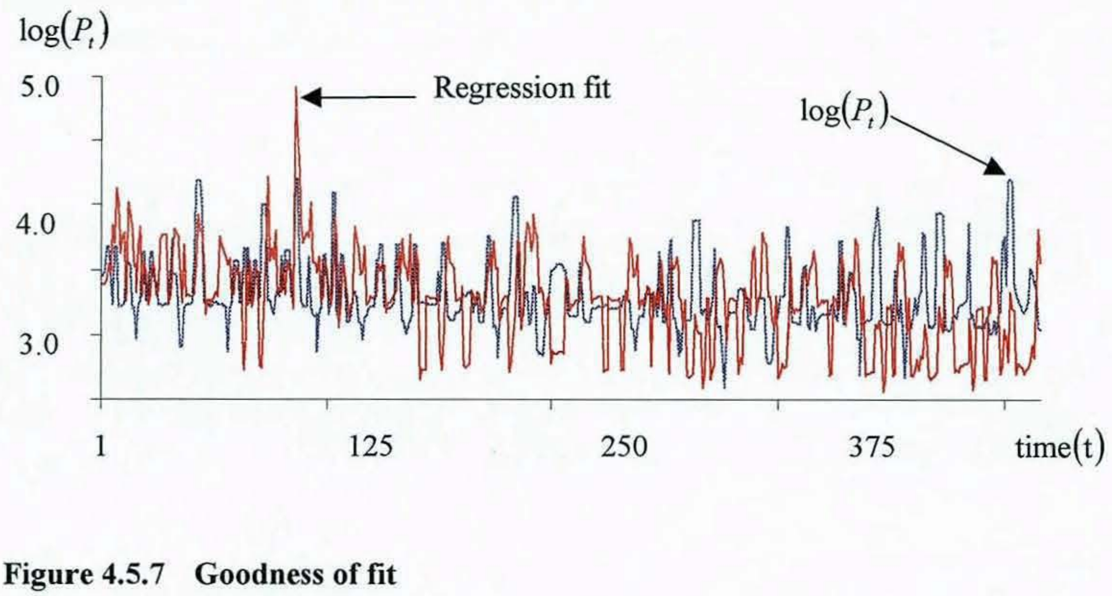

Figure 4.5.7 Goodness of fit

The predictability of the model, prior to the announcement by the secretary of state of a review into utility regulation is low. After the announcement of the review by the DTI, the model rejects the null hypothesis of the predictive failure test at the 5% level of significance, $\chi^2(500) = 311.47[0.000]$, so the forecast is more predictable after the event as figure 4.5.8 demonstrates. An interpretation of this result would be that generators were cautious not to draw attention to the government, over the issue of pool prices being above competitive levels. The strategy adopted included a reduction in the fluctuations in pool prices, and an overall reduction in this price, so the forecast over-estimated pool prices.

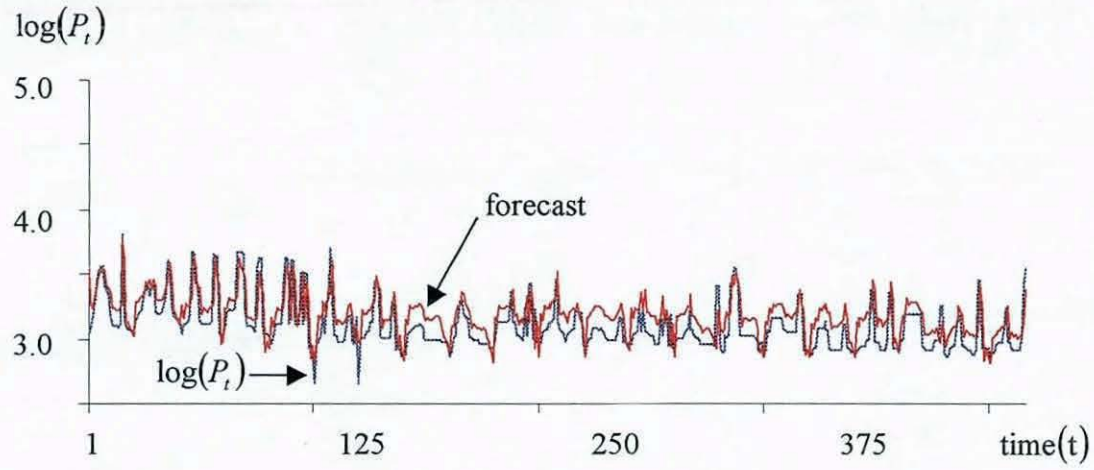

Figure 4.5.8 Forecast of $\log(P_t)$

Average demand forecasts before and after the announcement of a DTI review are broadly equivalent according to table 4.5.10 below. However the generators have reduced the level of their bids and the standard deviation in the auction after the event by over £5/MWh, which explains the lower pool purchase price. Unless the 200MWh of additional demand before 30th June 1997 cost £5/MWh more to supply, I would argue that the dominant generators have deliberately reduced SMP, strengthening the view that they are able to control non-baseload pool prices to suit their commercial aspirations.

	P	$\sigma(P)$	SMP	$\sigma(SMP)$	CP	$AVAIL$	DF
Ex-ante	25.48	8.50	25.13	8.23	0.35	48655	35185
Ex-post	20.41	4.43	20.05	4.09	0.36	48546	34967

Table 4.5.10 Average price and demand data

(g) Regulator investigates 3 plant closures

The model that was selected for constructing a forecast of pool prices is:

$$\beta(L,1)\ln(P_t) = \alpha + \gamma(L,3)\ln(DF_t) \tag{4.5.7}$$

with a forecast that overestimates the pool price. The predictive failure test shows that the overestimate in pool prices is significant at the 5% level of significance, $\chi^2(500) = 739.6[0.000]$, and is illustrated by figure 4.5.9. The combination of this investigation and the review of electricity trading arrangements may have forced National Power and Powergen to reconsider their bidding strategy into the pool.

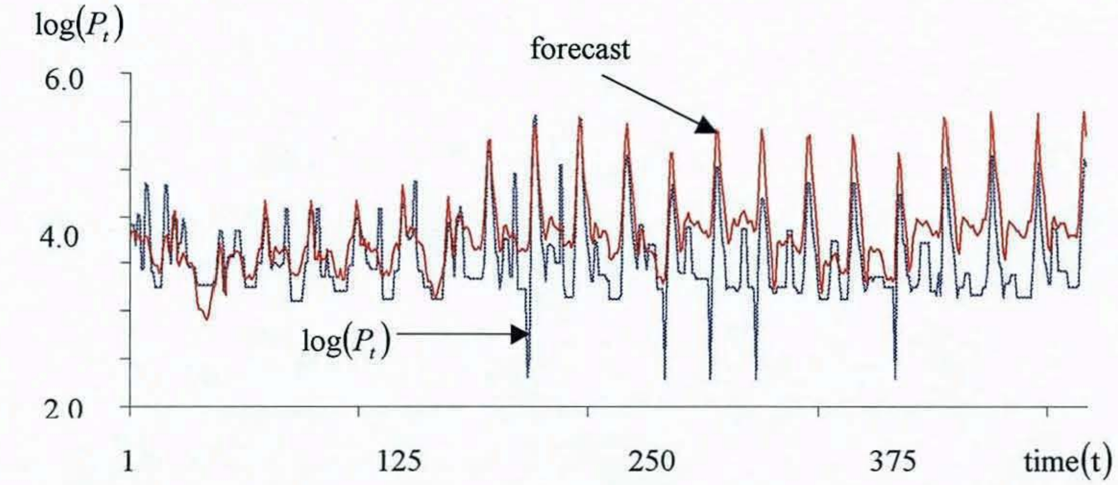

Figure 4.5.9 Forecast of $\log(P_t)$

Figure 4.5.9 shows that the regression is less predictable after the event has occurred, and further evidence of this increase in volatility is provided by table 4.5.11 below. The signal from the Minister for Science and Technology that pool prices should be lower may have been taken seriously by the generators.

	P	$\sigma(P)$	SMP	$\sigma(SMP)$	CP	$AVAIL$	DF
Ex-ante	32.60	13 29	32.15	12.81	0 44	51171	37118
Ex-post	46.93	24.52	43.18	16.59	3 75	56481	40457

Table 4.5.11 Average price and demand data

4.6 Comparison of pool prices in 1996 and 1997

To help set the scene, table 4 6 1 below summarises price and demand data for April in 1996 and 1997. Demand forecast remained similar in both years, while surplus capacity increased by 3GWh. An increase in availability should reduce the bids into the pool under the conditions of a competitive market place, as generators compete for market share. Instead the dominant generators have held SMP high to maintain margin payments in return for lower total sales.

Year	P	SMP	CP	$AVAIL$	DF
Apr-96	30.77	30 47	0 3	49502	36718
Apr-97	30 4	30 26	0.14	51850	36199

Table 4.6.1 Average price and demand data

Table 4 6.2 provides price and demand data for September in 1996 and 1997. When demand is similar in both years and underlying costs are equivalent in both years, then an increase in supply, which raises surplus capacity, should lower the system marginal price in a competitive environment. An increase in supply lowers the probability of shedding load, so capacity payments should also fall However there is an inverse relationship between the system marginal price and capacity payments, because although capacity payments were cut to negligible levels, the system marginal price increased from £19.89/MWh to £28 19/MWh.

Period	P	SMP	CP	$AVAIL$	DF
Sept 1996	40.00	19 89	20 11	45984	35519
Sept 1997	28 30	28 19	0 11	49497	36011

Table 4.6.2 Average price and demand data

4.7 Conclusion

Analysis of pool price behaviour was produced to complement the theory of price setting established in the generating market, and to consider the implications of some of the statements made in the literature Wolfram (1998) argued that the mark-up of prices over marginal costs is proportional to the number of infra-marginal units already accepted in the auction The ability to influence pool prices is also heightened by a firm who owns large scale plant compared to smaller size, predominantly combined cycle gas turbine plants.

Green (1999) develops on the contract model outlined by Powell (1993) to show that in a duopoly strategic environment, as characterised by the industry, the first firm would increase the number of contracts because the effect would be to increase the slope of the supply function. The optimal strategy for the second firm reduces the competitiveness of the pool because lower quantities at each price would be offered Furthermore Green (1999) has shown that the model is able to detect the ability of generators to earn a premium in the contracts market following their strategies in the pool. Ofgem have also been concerned about price setting behaviour of the major generators, leading to the idea of a change in their licence to force generators to behave with best intentions (market abuse condition) or face being referred to the Competition Commission

Four types of strategic behaviour have been inferred from the study of pool prices The break-up of the two Vesting contracts provided an opportunity for National Power and Powergen to exploit their dominance in the day-ahead auction Powell (1993) showed that if there is a level of contracting which is less than total generated output, the generators have the ability to exploit this by raising pool prices. Full contracting of electricity demand at Vesting implied that pool prices were constrained by the threat of new entry, because their level did not influence revenue streams. Strategic behaviour employed after these two events can best be summed as raising pool prices to increase revenue streams, constrained by keeping average pool prices below entry price.

A second type of strategic behaviour that is gleaned from the study is when the generators increase short-run profits This appears to have taken place following investigations into plant closures in 1992 and the regulatory support for maximum price restraints in 1997 An interpretation of this result is that profitability may be reduced by these political and regulatory events and so a policy that increased profitability before the trading environment tightened may have been adopted. However it may be difficult to argue that an anticipated windfall tax would force up pool prices if prices/outputs were already at profit maximising levels

A third type of strategic behaviour is associated with the credibility of reviews and investigations. A high degree of credibility from the regulator will induce generators to moderate their bids in the auction because they believe that the threat of intervention in the generating market is real, and could lead to a harder trading environment This is inferred from the regulatory investigation into three plant closures and the review of trading arrangements where forecasts of pool prices overestimated the true value Credibility may also explain why pool prices were higher than expected after the investigation into plant closures was announced in 1992 However in this case, the credibility of the regulator was not a significant factor.

The final type of behaviour that is inferred from the study concerns the decision by National Power and Powergen to reduce fluctuations and improve the predictability of the model after an event has taken place This was a symptom of the annual contract round in 1996/97 after the pool price cap expired, and the DTI review of regulation in 1997 This may be explained by the possibility of tighter regulatory action that would adversely impinge on the generators. To avert such a move, the generators may have calculated that it would be wiser to limit their dominance, which would otherwise increase awareness of their market power in the generating market.

These examples of strategic behaviour suggest that the generating market has failed to live up to predictions at privatisation that the market exhibited Bertrand competition. Moreover the study supports the models of Green (1996) and Green and Newbery (1992) that imply that there are considerable welfare gains that can be attained by divesting generating plant until there are five competing generators of a similar size in the market. Although Eastern is now in a position to create rivalry to National Power and Powergen, the incumbents have responded by reducing output in exchange for margins.

This work lends support to the divestment of a further 8GW of price-setting plant owned by National Power and Powergen in 1999. Will the new owners attempt to increase market share and hence lower their bids into the day-ahead auction? How will National Power and Powergen respond to the increase in competition? If pool prices remain unrepresentative of the underlying cost factors then further reform of the structure of the generating industry will be required

Chapter 5 Transmission Pricing

5.1 Introduction

Generation stations are situated all across England and Wales. There are also interconnections with Scotland and France, allowing electricity to be mostly imported to the England and Wales market Current transmission pricing strategy involves averaging the cost of constraints and losses across all electricity customers. Planning restrictions have played a role in limiting the potential sites in Southern England, but nevertheless this policy has provided weak economic signals, culminating in a bias towards generating stations being situated in the North of England. This is probably explained by the distribution of coal fields. However demand for electricity exceeds supply in the South of England. Electricity has to be transported into homes and businesses, which is achieved through the National Grid's transmission, and high and low voltage distribution networks. Electricity is essentially just like any other commodity, although it is expensive and difficult to store Hence most electricity has to be generated as it is consumed.

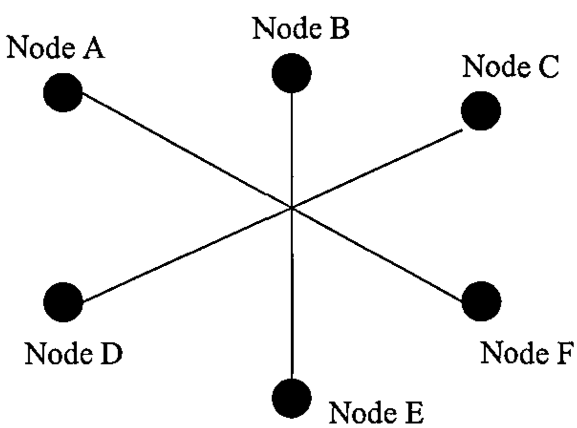

Figure 5.1.1 Simple transmission network with six nodes

A generator will supply electricity into the general system (network) at a location (node) on the system Figure 4 1.1 consists of three nodes where the generators are based in the North of England (A, B, and C) while electricity is withdrawn by suppliers at all six nodes. However electricity flows according to Kirchoff's laws, "essentially following the path of least resistance" (Hogan 1992, p.215) Therefore consumption at node F cannot be identified with generators at any particular node

The system operator is responsible for the day to day operation of the network. It maintains system balance between supply and demand at all times, to avoid power outages. Close co-ordination between generators and the transmission network is vital to endure equilibrium. Prior to privatisation it was thought that economies of scope between generation and transmission were so great that they might jointly exhibit natural monopolistic conditions, even though chapter three identified generation as a competitive industry. It was decided at privatisation that the costs of any losses from co-ordination were small compared to the gains in competition in generation

Suppose that electricity has to be transported from a node based in the North of England on the transmission network, defined as node A, to a Southern based node defined as node B A system operator (SO) will have an objective to minimise the total cost of energy going through the network This is attained when the differences between the economic value at node B and node A equals the marginal cost of energy production caused by extra power flows along the line connecting the two nodes. Assume the price of electricity at node A is equal to the marginal cost of generating at that node. Furthermore assume that this criteria also applies to node B The difference between the price of electricity at the two nodes represents the price of transporting electricity from node B to node A, shown by equation 5.1.1.

$$\text{transport price} = P_B - P_A \tag{5.1.1}$$

If the marginal cost of transporting electricity from node A to node B is less than the difference in the marginal generating costs at the two nodes, it is efficient for the system operator to call on extra generation at node A and transmit this to node B. As the supply of electricity across the line increases, so the probability of a constraint appearing on the line rises In an electric network there are two types of power, real power which runs appliances and reactive power which is stored and then consumed over a cycle so no actual energy is consumed However there are costs attached to reactive power because fluctuations in the local voltage across a line mean higher levels of current are required for a given amount of real power to be supplied The higher the resistance of a line the smaller the power flows across the line, thus acting as a constraint. There will also be some energy loss across a line that is converted into heat. A thermal limit for each line is required dependent upon heat dissipation, which restricts power flow across the line.

If there is a constraint in the network arising from the capacity of the line, between two zones, say for example X and Z that reflects certain parts of the England and Wales transmission network, then the price of transporting electricity should rise, if the correct economic signals are in place Consequently the price of consuming electricity in the exporting zone (X) should fall as the demand for higher-cost plants recedes. As supply of electricity declines in the importing zone (Z), the price of consuming electricity will tend to rise. The signals therefore encourage new entrants in the generation industry to locate in the importing zone (Z) because the returns are higher

As more plant locates in zone Z, so the price difference between the two zones should decline. The difference in the price between two nodes reflects the "shadow price" of constraints In an optimal efficiently regulated transmission system, the price of transporting electricity should be set at the marginal cost, taking into account the shadow price of network externality costs A new customer should pay the cost of reinforcing the network if as a direct result of connecting to it a constraint materialises on another part of the network.

So far, the model has represented a very simple transmission system, which has assumed no transmission losses, reflecting the desire to take away the complexities of such a network and look at the problem from first principles Clearly in an electricity network which is dominated by over 200 nodes, this simplistic approach has to be taken further to address the fundamental characteristics of England and Wales. Nevertheless the discussion above is an important starting point. Is it possible to incorporate these broad objectives into a transmission system for England and Wales?

5.2 Understanding of the issues of transmission pricing

Green (1997a) states six principles that should be at the centrepiece of transmission pricing. They are:

1 Promote efficient day-to-day operation of the bulk power market
2. Signal locational advantages for investment in generation and demand
3 Signal the need for investment in the transmission system
4. Compensate owners of existing transmission assets
5. Be simple and transparent
6 Politically implementable

In England and Wales, adding generation at the right place on the system (such as the South West of England or the South East interconnector) can reduce transmission constraints and result in significant cost savings. Marginal costs at one location depend on the rest of the system. Subject to constraints, economic efficiency requires the system co-ordinator to meet demand at the lowest cost possible. In a transmission network, the short-run marginal cost (SRMC) is the price of rationing demand along a line to remain within capacity limits An increment in energy flows will lead to a cost associated with the incremental losses, which occur as power flows from one node to another. This may also reduce spare capacity on the line A binding constraint will reduce cheap generation from the input side of the constraint and increase the dispatch of more expensive generation on the other side of the constraint

Long-run marginal costs (LRMC) include the cost of expanding the system and any remaining losses in the system By this we mean that the discounted present value of all losses and constraints on the present system is above the minimum cost of a new system with additional lines added. Expansion will occur until the marginal generation savings from importing electricity equal the marginal cost of building additional capacity. Line losses nevertheless will still materialise in an expanded system

Marginal costs can be split into two components

1. Costs of system losses
2. Opportunity cost of transmission constraints

Marginal transmission losses are caused by an increase in line flow (MWh) as is given by equation 5.2.1:

$$\text{marginal losses} = 2IR \qquad (5\ 2.1)$$

where I = current, and R = resistance of the line. Since current is proportional to line flow, then marginal losses are due to the additional current which materialises due to the increase in line flow. The consequences of transmission losses can be illustrated by figure 5.2.1.

Figure 5.2.1: Transmission Losses

If a generator at node A supplies 50 MWh to customers situated at the exit node at B, customers at node B will only receive 43 MWh The marginal physical losses total 7 MWh from this example, and so the marginal cost of supplying 50MWh at node B is calculated as:

$$MC_B = \frac{MC_A}{1-\lambda} = \frac{5}{1-(7/50)} = 5.81\text{MWh} \qquad (5.2\ 2)$$

where λ measures the proportion of the losses So long as additional line flow moves in the same direction as existing line flow, then the longer the distance from one node to another, the higher the losses But if the additional line flow moves in the opposite direction, in this case from node B to node A, the losses will fall. Using figure 5 2.1, 43 MWh is required to supply customers at node A with 50 MWh of electricity Hence the monetary gain is 81p/MWh, because the customer will only be charged

£5/MWh. For example if a generator and customer are in the same zone, the net value of the marginal loss is zero However if there is a notional national balancing point from where all electricity flows, and is then dispersed to exit nodes, then there will be positive and negative costs from the transmission of electricity

There are three types of transmission constraints· thermal limits, voltage limits, and stability limits. Assuming there are no transmission losses, the marginal costs of generation at nodes A and B will be equal when constraints are not binding Moreover the transmission costs will be zero. However if the capacity (MW) of the line linking nodes A and B for example exceeds the unconstrained level of transmission, then generation at node A will be reduced, and demand will be met by additional higher cost plants located at node B. The difference between the marginal costs at the two nodes represents the SRMC of transmission.

Constraints bind for only the last few MW units, so absolute savings from releasing constraints are small although the marginal cost of bringing on generators higher up the merit order may be high. Hence the merchandising surplus (revenue exceeds cost of constraint) may be used by the system operator to contribute towards the fixed cost of transmission Inevitably due the laws of physics, the closer generation and demand are sited together, the lower will be the costs of transmission

Transmission prices can be used to signal new investment. Green (1997a) however states three potential problems.

1. Most investments are lumpy, so after relieving the congestion, the price difference between nodes is largely eroded
2. Increasing the capacity of one link may reduce the capacity of others, so internalising positive and negative externalities
3. The transmission owner is likely to receive significant revenue from marginal cost pricing in heavily loaded lines, which cause constraints or high line losses.

Taking the first point, investment in strengthening a transmission line is characterised by indivisibilities, so a simple spot price for transporting electricity will not cover the cost of the link. This is because once the line is strengthened, it will be able to supply more electricity than was constrained previously. Hence this additional cost will fall quickly to negligible levels. If there were no indivisibilities, the system would only provide for existing customers, and would require immediate expansion to accommodate new customers

Indivisibilities are a common cost allocation problem. Suppose the total cost of strengthening the link between nodes A and B is given by equation 5 2.3

$$TC = \alpha + \beta x \qquad (5\ 2.3)$$

where x is the size of the expansion, α represents costs common to all users, and β is the marginal cost of strengthening the line. Setting a transmission price equal to SRMC will not cover the total cost of the improvement. Williamson (1966) looked at the peak-load pricing problem and using a social welfare function identified that off-peak users should pay the short-run marginal cost, while peak users would the combination of an incremental operating cost and incremental capacity cost This has led to the idea of common costs being allocated to those customers whose demand is least sensitive to price changes (inelastic demand curve) so investment is not distorted. This is a characteristic of Ramsey pricing

A market operator is responsible for the organisation of the day ahead spot, ensuring electricity dispatch meets the cost minimisation criteria. If the market operator could signal to users of the network the price of electricity at every node, then the price of transmitting electricity from one node to another is referred to as nodal pricing. However if the price of nodes within a zone is similar, zonal transmission pricing may be used, an approach adopted by the Norwegian electricity market

Since there are economies of scale due to lumpy investment in the transmission network, one of the objectives of transmission pricing must be to provide adequate revenue to function as a National Grid Company. Ramsey prices would differentiate prices inversely proportional to the elasticity of demand and is efficient because it maximises "consumers' surplus, using only the minimal monopoly power required to raise the required revenue" (Wilson 1993 p.121). In practice it has proved difficult to ascertain the elasticity of demand. Furthermore some customers will be disadvantaged by these proposals A pareto improving non-linear tariff is superior to Ramsey pricing and is demonstrated by the following menu of contracts.

$$P_1(q) = p_1 q \tag{5.2.4}$$

$$P_2(q) = P_2 + p_2 q \tag{5.2.5}$$

where P_2 = common costs, p_1 = uniform price, $p_2 < p_1$. Nonlinear pricing offers quantity discounts so a critical mass is reached which will provide benefits to the customer of expanding the transmission network whilst at the same time meeting the revenue adequacy criteria. Furthermore self-selection of tariffs overcomes the problem of adverse selection unless information asymmetry is very serious.

The three problems noted by Green (1997a) can also be solved as long as incentives are placed on NGC which discourage revenue being raised from constraints on the system NGC already has incentives placed on them, with the transport uplift component taken out of pool price derivations, which has been successful in minimising this component Investment in the infrastructure of the transmission network requires planning of many years. It would be cost effective to bring forward investment if the net present value of future expected investment is greater than the current cost of this investment. This is often the case because of economies of scale due to lumpiness So one of the challenges of setting out a structure for transmission pricing is how to insure the risk that an investor incurs, when it decides to build additional lines based on expectations, when future demand may not materialise The Arrow-Lind theorem says that the only investor who can be risk neutral with respect to GNP fluctuations is the accumulated mass of society/taxpayers, since its loss of income to each is likely to be small.

5.3 Transmission pricing in England and Wales

The national grid company (NGC) provides two licensed services: Use of System, and Connection NGC levies an annual connection charge for the provision of the physical assets that provide access to the transmission system for generators and suppliers. The charge is based on the connection assets provided, capital and maintenance costs of these assets, and to ensure a reasonable rate of return. Use of System is divided into the *Transmission Network Use of System* and *Transmission Services Activity.*

Centrally despatched generators and all suppliers who use the transmission system incur a Transmission Network Use of System (TnUOS) tariff, which is calculated using the *investment cost related prices* (ICRP) transport model The model calculates the marginal cost of investment in the transmission system which would be required as and when demand or generation increases at each node on the system NGC groups nodes of similar cost characteristics into zones. It is this part of the TnUOS tariff that reflects cost reflective geographical signals

Defining the distance from node (i) to node (j) as C_{ij} and the corresponding flows as x_{ij}, the transmission pricing model is designed to minimise the distance between nodes (equation 5 3 1) subject to the constraint that the flow between the nodes equals the difference between generation (G_i) and demand (D_i) at that node The primal with balance is written as:

$$\text{Min} \sum_i \sum_j c_{ij} - x_{ij} \qquad \text{(allow flows in both directions)} \qquad (5\ 3.1)$$

$$\text{s t} \ \sum_j x_{ij} = (G_i - D_i) \equiv S_i \qquad x_{ij} \geq 0$$

Re-writing the model as a weak inequality:

$$\text{Min} \sum_i \sum_j c_{ij} - x_{ij} = C^* \qquad (5\ 3.2)$$

duals

$$\text{s t} \ \sum_j x_{ij} \leq (G_i - D_i); \qquad w_i$$

$$\rightarrow -\sum_j x_{ij} \geq (D_i - G_i)$$

The dual of the transmission pricing model can be expressed as:

$$Max \sum_i (G_i - D_i) w_i \qquad (5.3\ 3)$$

s.t. $w_i \leq c_{ij}$

The marginal cost at node (i) is derived from the model as:

$$w_i = \left[\frac{\partial C^*}{\partial (D_i - G_i)} \right] \qquad (5.3.4)$$

ICRP recovers less than a quarter of the required revenue allowed by Offer under the present price control. The remaining tariff zone is accounted by a uniform Security and Residual charge, which is not differentiated by location. In his proposals for NGC price controls in 1996, the regulator suggested "there is a danger that NGC's charges artificially stimulate the demand for more transmission lines" (Offer 1996a, p.32).

A quarter of the revenue is collected from generators and three-quarters from suppliers. Zonal differences reflect the differences in marginal costs A low tariff implies that the generator of supplier concerned contributes proportionately less to transmission constraints compared to a high tariff The dual of the problem is used to explain the negative generation charges in the South of England A one unit increase in generation will lower the costs of reinforcing the transmission network. This is because net electricity power flows from a node based in the North to a node located in the South will be smaller, and hence the need for additional capacity is reduced

NGC demand charges are based on a per kW of triad demand (average system demand over three half-hours between November and February, reflecting the highest and the next two highest, separated from each other and the highest by at least ten days). However these charges are not the shadow prices of solving equations 5.3 2 and 5.3.3.

The present system operates *shallow entry pricing* When a new customer is brought onto the system, the costs assigned to the area will change, but the marginal cost is not reflected in this customer's transmission charge because the change in costs will be reflected in the charges to all users in that area. In contrast *deep entry* charges would allocate all the increase in network costs to the new customer However politicians with parliamentary constituencies in the South of England realise that a switch towards *deep entry* charges will increase the bill for their customers This is the externality argument in favour of *shallow entry pricing* because the politicians will argue that customers in the South should not be penalised as a result of geographical location.

The regulator expresses his opinion that "more cost-reflective use-of-system charges would better inform the future location of new generation plant and closure decisions of existing plant" (Offer 1996a p.32). NGC's 1996 seven-year statement reported that in four northern zones very little additional generation could be accepted without inter-zonal transmission reinforcement. In contrast at least 2 GW in-merit generation could be accepted without such need in the Peninsula, Wessex, and Inner London

Green (1997b) identifies NGC zones 9 and 10 (South Wales and the adjacent part of England), where there is 4GW of plant, but 3.5GW belongs to National Power alone. If the zones were affected by an import constraint, one of the company's stations might be constrained-on and paid it's own bid price Changing to zonal prices for constraints would increase the income of plants that normally run, and give the constrained-station an "undesirable incentive to raise its bid". Nevertheless Green (1997b) estimates that the "regional differential in transmission prices should increase by at least 50%" (p.192) Higher regional prices would increase the number of new entrants in the area, thus improving the competitiveness of the market

As a licensed monopolist, NGC does not require external price signals for investment purposes. It has to operate an efficient and economical network. Green (1997b) points out that internal signals would be useful for NGC to identify where investment is required For example a significant difference in prices between nodes would imply either large constraints or there are considerable marginal losses. The present arrangements do not provide such a signal. Instead of electricity following the path of least resistance (Kirchoff's law), NGC assumes electricity flows by the shortest route. They also implicitly assume that a line is at full capacity In practice line losses may be so high that it is cheaper to operate a line at half its rated capacity. System security also necessitates spare capacity.

NGC's Ancillary Services Business buys reactive power, short-term reserve, and other services from generators, and passes the cost onto the pool. Transmission constraints were paid for in a charge known as 'operational out-turn'. In 1994, NGC was provided with incentives to minimise costs by completing maintenance more quickly, minimising the number of circuits out of commission etc Therefore the costs that NGC could influence were included in the Uplift Management Incentive Scheme (UMIS) in 1994, and the Transmission Services Scheme (TSS) in April 1994/95 TSS sought to identify the costs of constraints more accurately by:

1. Calculating an ex-post unconstrained schedule (EPUS) for each settlement run using actual demand and actual availability corrected for generator shortfall
2. Difference between this schedule and the dispatched schedule of generation plant is due to transmission constraints.

TSS allowed NGC to recover a regulated target level of transport and reactive power uplift costs plus a 20% bonus or penalty for beating or falling short of the target. Changes were made to the Pooling and Settlement Agreement and the Transmission Licence in 1997, which required NGC to pay out turn costs of Transport Uplift into the Pool, and NGC would make a Transmission Services Use of System charge

$[TSE_{cd}]$. On the last day of the year, NGC's revenue will equal maximum allowed revenue TSE_{cd} payable by customer (c) on settlement day (d) as is neatly shown by equation 5 3.5.

$$TSE_{cd} = [(CBT_d - CBT_{d-1}) + (CBR_d - CBR_{d-1})] \bullet \frac{\left(\sum_{j}^{A} TAD_{cj}\right)}{\left(\sum_{c}\sum_{j}^{A} TAD_{cj}\right)} \qquad (5\ 3\ 5)$$

where CBT_d is the transmission services uplift balance of income to date; CBR_d is the reactive power uplift income to date; TAD_{cj} denotes the MWh share of Table A gross demand taken by each customer in each settlement period

The Pool Committee has recently attempted to address the issue of transmission losses. The present policy is to adjust metered demand, by adding average losses so that it equals metered generation Therefore the price of demand for everyone is increased to reflect average losses There are no locational signals however in this methodology. In future, the pool has recommended that metered demand and generation in each zone would be adjusted by a *scaled marginal loss factor*. This will have the effect of reducing prices in the North and raising them in the South, but would avoid the problem of marginal transmission losses driving average costs.

The objective is to ensure that the expected cost of losses is met by net revenue. Previously the demand-side was responsible for all losses. However to provide appropriate signals for the location of generating plant, transmission losses will be shared equally between the demand and supply side. Therefore demand charges are expected to fall or rise at a slower pace A consequence of this change is that if the threat of entry keeps prices down, Northern generators will be expected to bear much of the cost of losses

If losses are ignored in the merit order, Northern stations with lower bids will be scheduled, even though total system costs would be lower by using Southern stations which initially submitted higher bids. Referring back to the possibility of transferring

105MW of generation in the North for 95MW in the South-West, Green (1997b) calculates that this measure would save 10% in capital costs Operating costs would also be lower, so total gross savings might be £10m-£15m per year per GW of each new plant The net savings would be lower as the cost of transporting gas to the station would rise. Nevertheless locational prices based around transmission losses can provide appropriate signals for investment in the network

The interaction of gas and electricity is becoming increasingly important, particularly since CCGT generating stations have come on stream. Investors in Combined Cycle Gas Turbines (CCGT) have a choice between investing in the North of England and transmitting electricity to the South, or locating in the South of England and transporting the gas used to drive the turbines down Transco's pipes Effective locational signals for transporting energy from North to South requires:

$$LRMC_{transco} - LRMC_{NGC} = \text{Transco charges} - \text{NGC charges} \qquad (5.3.6)$$

5.4 An overview of contracts for transmission

Clearly the discussion above has concentrated on how to provide incentives for the National Grid Company to invest in the network, without exploiting its monopoly position At the same time the generators and customers to a lesser degree require information about geographical differences in the cost of transporting electricity, when deciding where to locate plant and businesses. Without such a mechanism, transmission prices will remain inefficient.

System users in an ideal model should be charged the short-run marginal cost for crossing a constraint in the network, and for transmission losses Concentrating on the former, we know that these costs can vary significantly from one period to another. Users will therefore wish to insure against the risk of such volatility A long-term contract could be used to hedge this risk, in the same way as a financial contract-for-differences (CfDs) has been successfully used by generators and suppliers for hedging the risk of energy price fluctuations.

A generator or supplier could take out a cfd for a fixed volume of electricity to cross a particular line, which was vulnerable to bottlenecks Volume not covered by the contract would be traded at the spot price, defined as the difference between the marginal cost of generating electricity at two nodes (equation 5.1.1). This has been referred to as *nodal pricing*. Financial CfDs have the advantage that economic dispatch is not affected, and so unlike physical contracts, they do not have to be traded to achieve the optimality. Furthermore the possibility arises of introducing forwards and futures contracts for transmission alongside energy use for up to five years out. This would assist NGC in forward planning, hedging risk, and price discovery. It would also provide increased competition for generators and suppliers, as financial institutions compete with industry players.

An example would assist in understanding the financial contract.

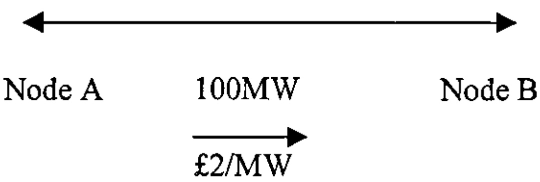

Figure 5.4.1 Financial Transmission Contract

In figure 5 4 1, I have assumed that a generator at node A has signed a financial CfD with NGC for a fixed volume of 100MWh to be transferred from its injection node A to node B for £2/MWh. Suppose that there is a constraint on the line, which limits the line flow to 75MWh, and the cost of transmission increases to £3/MWh The generator would owe NGC £200. NGC would owe the generator £300. Therefore NGC would pay the generator £100

Generators and suppliers could purchase firm transmission rights. These rights would enable the holder to transport a specific volume of electricity at all times. In the case that NGC denies access to the network, compensation would be paid out. The cost of the firm right would be based on the expected costs of the constraint, which would be directly attributable to the user Hence contracts would reflect "deep entry costs". Losses could also be included in this, based on the expected cost of buying energy to meet the losses. NGC would have to decide if it is more economic to invest in the network and save on constraints.

5.5 Options for implementing transmission contracts

There are two types of power flows in a network, and they are real power flows and reactive power flows. Consequently there are two types of constraints. Thermal constraints are attributed to real power flows, whereas voltage magnitude constraints occur with reactive power flows In their seminal paper, Schweppe et al (1988) concentrate on real power flows, and derive spot prices. In their model, marginal operating costs are assumed to exceed average variable operating cost, thus the excess revenue collected contributes but may not entirely cover the capital costs, under conditions of optimal dispatch.

Hsu (1997) summarises the model by Schweppe et al (1988).

$$Max\,\Omega = \qquad (5\ 5\ 1)$$

$$\sum_k B(d_k) \qquad \text{“sum of customer benefits”}, \quad B'(d_k) \equiv p_k \qquad (5.5\ 2)$$

$$-\left\{\sum_j G_j(g_j)\right. \qquad \text{“generators fuel and maintenance cost functions”} \qquad (5\ 5\ 3)$$

$$+\gamma\left[\sum_j g_j - \sum_j \bar{g}_j\right] \qquad \text{“total generation constraint”} \qquad (5.5.4)$$

$$\left.+\sum_j \mu_j^m (g_j - \bar{g}_j)\ \right\} \qquad \text{“individual generation constraints”} \qquad (5.5\ 5)$$

$$-\left\{\sum_i \mu_i^Q (z_i - \bar{z}_i)\right\} \qquad \text{“individual line constraints”} \qquad (5.5.6)$$

(where $z_i = z_i(\underline{g}^*, \underline{d}^*)$ depends on generation less generation at swing node, and demand less demand at swing node).

$$-\mu_e\left[\sum_k d_k + \sum_i L(z_i) - \sum_j g_j\right] \qquad \text{“total energy balance equation”} \qquad (5.5.7)$$

(where $d + L(z) = g$).

It is important to note that $z_i = z_i(g_1^*, \; , g_j^*, d_1^*, \ldots, d_k^*)$, which says that power flow through line (i) depends on generators and demand at every node, by every generator and every customer except at the swing node There are no constraints at the swing node since this is the location of the marginal generator who will not be operating at full capacity.

Nodes are implicitly defined by generator(s) (g_j) and customer(s) (d_k). Hsu treats customer (k) and location (k) as the same Kuhn-Tucker first-order conditions are

$$\frac{\partial\Omega}{\partial d_k} \le 0; \;\; d_k \frac{\partial\Omega}{\partial d_k} = 0 \qquad (5\ 5\ 8)$$

$$\frac{\partial\Omega}{\partial g_j} \le 0, \;\; g_j \frac{\partial\Omega}{\partial g_j} = 0 \qquad (5\ 5.9)$$

$$\frac{\partial\Omega}{\partial \gamma} \le 0, \;\; \gamma \frac{\partial\Omega}{\partial \gamma} = 0 \qquad (5.5\ 10)$$

$$\frac{\partial\Omega}{\partial \mu_j^m} \le 0; \;\; \mu_j^m \frac{\partial\Omega}{\partial \mu_j^m} = 0 \qquad (5.5\ 11)$$

$$\frac{\partial\Omega}{\partial \mu_i^Q} \le 0, \;\; \mu_i^Q \frac{\partial\Omega}{\partial \mu_i^Q} = 0 \qquad (5\ 5\ 12)$$

$$\frac{\partial \Omega}{\partial \mu_e} \leq 0, \quad \mu_e \frac{\partial \Omega}{\partial \mu_e} = 0 \tag{5.5.13}$$

Assuming equations 5 5.10 to 5 5 13 hold with equality and binding constraints, Hsu concentrates on re-arranging equation 5.5.8 and 5 5.9.

$$p_k = \mu_e \left[1 + \frac{\partial \sum_i L_i}{\partial d_k} \right] + \sum_i \mu_i^Q \frac{\partial z_i}{\partial d_k} \equiv p_k \tag{5 5 14}$$

$$-\left[\gamma + \frac{\partial G_j}{\partial g_j} + \mu_j^m \right] - \sum_i \mu_i^Q \frac{\partial z_i}{\partial g_j} - \mu_e \left[\frac{\partial \sum_i L_i}{\partial g_j} - 1 \right] = 0 \tag{5.5.15}$$

$$\rightarrow \left[\frac{\partial G_j}{\partial g_j} + \gamma + \mu_j^m \right] \equiv p_j = -\mu_e \left[\frac{\partial \sum_i L_i}{\partial g_j} - 1 \right] - \sum_i \mu_i^Q \frac{\partial z_i}{\partial g_j} \tag{5.5.16}$$

At any node where generator (j) and customer (k) coincide, efficiency is equally affected by an increase in generation (g_j) exactly offset by a decrease in demand (d_k), implying $p_k = p_j$

The price paid to generators is the sum of equation 5 5 17 and 5 5 18.

$$\left[\frac{\partial G_j}{\partial g_j} + \gamma + \mu_j^m \right] \tag{5 5 17}$$

$$\left[-\mu_e \left(\frac{\partial \sum_i L_i}{\partial g_j} - 1 \right) - \sum_i \mu_i^Q \frac{\partial z_i}{\partial g_j} \right] \tag{5.5 18}$$

The price paid by customers is:

$$p_k = \mu_e \left[\frac{\partial \sum_i L_i}{\partial d_k} + 1 \right] + \sum_i \mu_i^Q \frac{\partial z_i}{\partial d_k} \qquad (5\ 5\ 19)$$

The price paid to generators can be interpreted as:

[generators costs + generators capacity shadow price + individual capacity shadow price]

$$-\left[\text{total line loss shadow price} + \sum_i \text{individual line capacity shadow prices} \right]$$

Likewise the price paid by generators is explained by

$$\left[\text{total line loss shadow price} + \sum_i \text{individual line capacity shadow price} \right]$$

The next stage is to choose a reference point, defined as the reference node containing the marginal generator at time (t). This will therefore change every half-hour. By definition the generators and demand at the swing node are excluded from g^* and d^*

At the swing node, $\frac{\partial z}{\partial g^*} = 0$ and $\frac{\partial \sum_i L_i}{\partial g^*} = 0$, so the generators price at the swing node is defined as.

$$p^* = \mu_e = \frac{\partial G}{\partial g^*} + \gamma + \mu_j^m \qquad (5.5\ 20)$$

However if the swing has the marginal generator, it is below capacity and so $\mu_j^m = 0$

$$p^* = \mu_e = \left[\frac{\partial G}{\partial g^*} + \gamma \right] = [\lambda + \gamma] \qquad (5.5.21)$$

where λ is system λ Replacing μ_e with $[\lambda + \gamma]$ the price paid by customers is·

$$p_k = \left\{ (\lambda+\gamma) \right\} + \left\{ (\lambda+\gamma)\frac{\partial \sum_i L_i}{\partial z_i}\frac{\partial z_i}{\partial d_k} \right\} + \left\{ \sum_i \mu_i^Q \frac{\partial z_i}{\partial d_k} \right\} \qquad (5\ 5\ 22)$$

$$\downarrow \qquad\qquad\qquad \downarrow \qquad\qquad\qquad \downarrow$$

$$\left\{\begin{array}{l}\text{marginal variable}\\ \text{generating costs +}\\ \text{generating system}\\ \text{capacity premium}\end{array}\right\} + \left\{\begin{array}{l}\text{network marginal}\\ \text{losses valued at}\\ \quad(\lambda+\gamma)\\ \end{array}\right\} + \left\{\begin{array}{l}\text{line congestion}\\ \text{premium}\end{array}\right\}$$

The first term represents the system marginal price (SMP) in the electricity pool plus (i) premium for overall capacity shortage or, (ii) value of lost load (VOLL) or, annualised cost of a peaking plant needed for system stability Customer dependent transmission line losses are explained by the second term. If a customer (k) experiences line congestion, the shadow price for line (i) measures the opportunity cost of either transmitting power across a congested line or using higher cost generating units on the other side of the line as defined by the third term This enables the system operator to alter the dispatch of electricity to meet demand. Equation 5 5 22 is simplified so the spot price for location (k) is:

$$p_k = (\lambda+\gamma) + \eta_{Lk} + \eta_{Qk} \qquad (5\ 5\ 23)$$

If $\eta_{Qk} < 0$ then customer (k) lowers system congestion by increasing consumption. This is identified as a positive externality In the England and Wales model, marginal generating units are located in the South, which is an importing region. Therefore if customers in the North (exporting region) raises demand then power flows from the North to South are reduced, thus relieving congestion and lowering $(\eta_L + \eta_Q)$ component for every customer at location (k)

The difference between prices at two locations is defined as:

$$\Delta p_{12} = p_2 - p_1 = (\eta_{L1} + \eta_{Q1}) - (\eta_{L2} + \eta_{Q2}) \qquad (5\ 5\ 24)$$

Treat η_{Lk} as operating costs of the transmission system (i.e. losses) and η_{Qk} as congestion premium of line capacity. Therefore if the buyer withdraws power at node 2 and the seller injects power at node 1, Δp_{12} will produce the efficient transmission charge to the parties

The focus of the remaining part of the chapter will be on how to signal efficient transmission prices There are three alternative models for dealing with the ownership of transmission capacity rights:

1. Contract path
2. Contract network (Hogan 1992)
3. Property rights / network externality model (Chao and Peck 1996)

Joskow and Schmalensee (1983) conclude "decisions at any point in a power system affect costs everywhere in the system" (p.63), and they argue that externalities can be reduced by horizontal and vertical integration. In brief the externality arises because the transmission capacity between any two nodes in a network depend on both the physical characteristics of the network and the pattern of power transactions. Kirchoff's laws of power flowing along a line of least resistance lead to a divergence between the contract path and physical path of power flows. Therefore the private cost and social cost do not converge.

A contract path is inefficient in short-run marginal cost terms because it is based on a postage stamp or per MW mile contract As such least cost dispatch will only occur by accident The other two methods however are consistent with providing the pricing signals for efficient dispatch, and hence meet the condition of equation 5.5.23. Hogan (1992) outlined a centralised system for a defining long-term capacity rights while ensuring the short-run efficient use of the transmission network. The system operator at each node allocates capacity rights based on the feasibility constraints of the network.

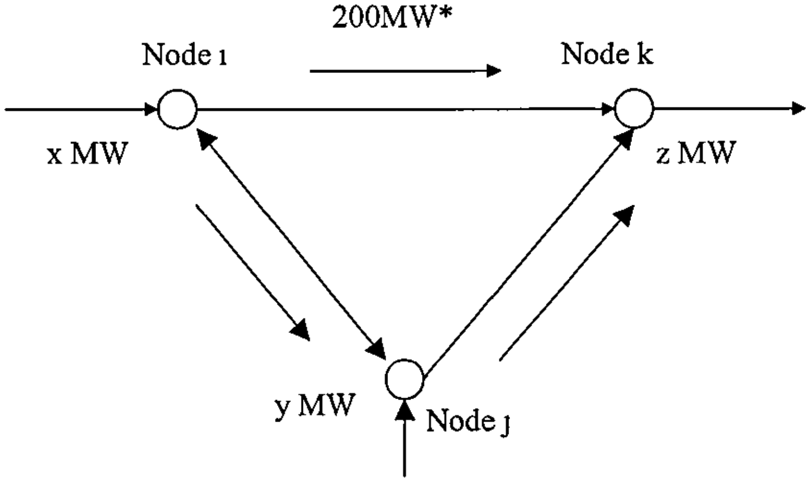

Figure 5.5.1 Contract model based on Hogan's capacity rights

When the capacity limit of 200MW connecting node k to node i is binding node j must be used as the injection node to meet an increase in demand at node k A binding constraint means that nodal prices will not be equivalent, and so the system operator will collect congestion rent from customers at node k. Generators will receive revenue for selling electricity at nodes i and j. The system operator will use the congestion rent (premium) and distribute this to the holders of the capacity rights. For example if generators at node i hold all the feasible capacity rights, then the congestion rent is derived as the opportunity cost of not being able to sell this amount of electricity at node k, and instead having to purchase electricity at node k to meet the contracted demand. The opportunity cost payment is made by the user who created the constraint, thus exhibiting the characteristics of "deep-entry" pricing

Hsu (1997) showed how a contracts network can help finance investment in the transmission network Total line losses are proportional to the square of the power flows in a transmission network, implying that marginal losses exceed average losses Consequently total revenue collected by the system operator will exceed average losses of the network, which Hsu refers to as a merchandising surplus

Chao and Peck (1996) showed that a distribution of property rights can always be found so that the market mechanism is able to overcome the externality problem in a decentralised system as opposed to the centralised approach outlined by Hogan (1992) This corresponds to the Coase theorem (1960) and is subject to the qualifying assumptions on transaction costs that usually hold High transaction costs will inhibit the efficient organisation of the market mechanism Pigou (1920) argued that a party who caused a nuisance should be required to pay damages, using the principle of common law. Economic efficiency is attained by internalizing social costs. The Coase theorem disagrees with the idea that centralisation is required to achieve efficiency Instead the principles of property rights are enshrined to replicate a social optimum

To illustrate, a holder of the transmission congestion contract (TCC) between two nodes has the right to send electricity between these nodes. However the holder can sell this right to another participant in exchange for a sum of money Regardless of the initial allocation of transmission rights, trading between industry and non-industry participants will continue to trade until there are no potential gains from such activity. This occurs when other participants do not value existing contracts higher than the current holders do. Under this assumption transmission rights are allocated efficiently

Chao and Peck (1996) incorporate a trading rule in their decentralised system of transmission rights Participants who directly create transmission losses will be required to pay for this externality. However the model embodies the principles of Coasian property rights to deal with transmission congestion. They obtain a derivation for the price of electricity at node (l) as:

$$p_l = p_k + p_n \lambda_{kl} + \sum_{i=1}^{n} \sum_{j=1}^{n} \left(\pi_{ij} + p_n \phi_{ij} \right) \beta_{ij}^{kl} \qquad (5\ 5.25)$$

Equation (5.5.25) shows that $\left[\beta_{ij}^{kl} \equiv \beta_{ij}^{k} - \beta_{ij}^{l}\right]$ units of transmission capacity rights on the link (i, j) are required for purchasing a unit of power at node k for sale at node l. Coasian property rights are defined as $\left[\pi_{ij} \beta_{ij}^{kl}\right]$, which is zero when the link (i, j) is not congested, Pigouvian externality for the link (i, j) is $\left[p_n \phi_{ij} \beta_{ij}^{kl}\right]$; and the cost of the transmission losses is $p_n \lambda_{kl}$. Moreover we can say that this result is analogous the efficient pricing model of equation (5 5 23) which demonstrated optimal dispatch

Cournot competition is where firms typically withhold generating capacity to raise price. Given all suppliers assume that all other suppliers will hold their output constant, a supplier will bid their marginal cost up to their limiting quantity. Stoft (1999) showed that a transmission congestion contract (TCC) could affect this strategy. Assume that no generator will bid a quantity into the pool less than its TCC hedge. If there is excess generating capacity (total generating capacity less line capacity) and it is lower than the capacity of largest generator, the largest generator is able to exercise market power by withholding sufficient capacity to prevent congestion of the line

However if excess capacity exceeds the capacity of the largest generator, the largest generator will not be able to withhold capacity to increase the nodal price Stoft (1999) suggests that a TCC has a strategic value as a hedging instrument under this condition A TCC in this circumstance will have a value equivalent to the competitive congestion rent. When there is no congestion, generators will receive revenue $q(p_k - p_i)$, and this is shown to be indifferent to the revenue it would receive if there were congestion. Consequently owners of transmission network will receive their competitive value of the TCC, while generators will not be able to capture the congestion rent

5.6 Conclusion

The privatised electricity industry supported inefficient transmission prices Transmission losses and constraints are two network externalities that exist in the transmission system. In general the greater the distance electricity flows on the system, the higher the level of losses Since electricity tends to flow from the North to South of England, new generation capacity in the North of higher demand in the South tends to increase transmission losses and constraints.

NGC can reduce the level of transmission losses by increasing the capacity of the system, and investing in low loss transformers. Furthermore it is able to influence the pattern of generation and demand via the structure of transmission charges. This is what chapter five investigates to minimise losses and constraints. The charging structure should ensure that price signals encourage new generation to be sited near demand. Increased differentials in charges between Northern and Southern zones may lead to new generation being located in high demand Southern zones On the otherhand if generators invested further in Northern zones, this might necessitate a strengthening of the transmission system, which is inefficient under average pricing By bringing price signals into line with costs, the structure of charges encourages new generation and demand to be located closer together

Non-economic factors deterring investment in new generation such as planning consents and environmental generators may dampen the effects of locational pricing in the short-term In the longer term, they may be expected to increase plant investment in the South either through delayed plant closures or new plant development, thus reducing capital expenditure of NGC, which will benefit customers Therefore distance-related pricing will remove some of the demand for more transmission lines.

A market mechanism has been shown to resolve these problems by Chao and Peck (1996) using the ideas of trading property rights to achieve the social optimum Locational pricing raises potentially significant externalities because customers in the South-West of England would be expected to incur a higher transmission charge compared to customers located in the North-East This is because the largest constraints on the network occur where power flows from Northern generators to Southern customers. Efficient pricing would assist NGC in finding out the value placed on upgrading the grid by generators and customers, and whether it is economic to go ahead with it

Thus it is recommended that the Coasian property rights approach be used to achieve efficient transmission pricing whilst ensuring marginal losses are financed adequately. Environmental concerns will have to be balanced with plans to relieve congestion If customers do not want plant located in the South, they should be expected to pay more for electricity because power has to flow in the direction of the congested line. At least the correct signals are in place to show that such a move will be lead to higher transmission charges for customers in the South and generators based in the North.

Chapter 6 Performance of the distribution companies since privatisation

6.1 Introduction

This chapter presents the results of a study into total factor productivity growth of the twelve England and Wales distribution companies between 1990/91 and 1997/98 The Conservative administrations in the 1980s replaced government ownership by economic regulation as part of the privatisation programme, which was designed to bring in private sector practices while raising much needed resources for the government. Traditionally governments used publicly owned companies to pursue general economic goals such as full employment. However this would have the perverse effect of reducing the efficiency of these companies

Economists have several definitions of efficiency or explanations of inefficiency. *Scale efficiency* means that it is efficient for a monopolist to operate the regional distribution network. This is because the costs of constructing two competing local networks are large relative to the operation, maintenance, and reinforcement costs of transmitting electricity into each home There are also economies of scope, since the costs of supplying domestic, commercial and industrial customers is less than the sum of supplying each of these types of customers separately

Wolak and Patrick (1997) identified in a study of the England and Wales pool that consumers have low elasticities of demand for electricity supply. This means that an un-regulated distribution company could charge access prices to the local network, which result in prices tending to be set way above marginal cost for customers who have inelastic demand. Since this is second-best pricing for a monopolist inefficient consequences should be secondary to delivering appropriate incentives for cost reduction.

Companies are profit maximising monopolists as the discussion above has indicated Ramsey pricing is consistent with this approach but there are concerns that incentive schemes may not lead to the magnitude in reductions of operational and capital expenditure in a secure market place. The current regime provides a bias in favour of reducing operating expenditure because companies are able to keep all the gains whereas in net present value terms a reduction in capital expenditure will only lead to 40% of the savings being kept, since the price control element of capital is based on an allowable return and depreciation. Furthermore strategic behaviour may lead companies to not make the fully efficiency savings possible in one price control period, so there is sufficient slack to remove in the following price control whilst meeting the demands of shareholders expectations. Incentive-based regulatory regimes such as a price cap are designed to minimise costs wherever possible and introduce innovative products (dynamic efficiency) in the same way as firms behave in competitive markets. As indicated above further refinement in the treatment of operating and capital expenditure trade-off is required *Dynamic and technical efficiency* effects are judged to be more important in the long run than deadweight welfare loss considerations, because productivity improvements will be passed on directly to the customer who will benefit from more competitive prices.

Prior to privatisation, the twelve area electricity boards of England and Wales purchased wholesale electricity on a bulk supply tariff from the Central Electricity Generating Board (CEGB). The emphasis was on setting price at long-run marginal cost, which in effect characterised cost-plus regulation. Weyman-Jones (1995) argues that these contracts, which encouraged X-inefficient behaviour in asymmetric information games, characterised by moral hazard "was one of the reasons for the emphasis given to the privatisation programme of recent years". In the 1980s, the Conservative government introduced stricter financial controls for the utility industries, in preparation for their eventual sell-off to the private sector.

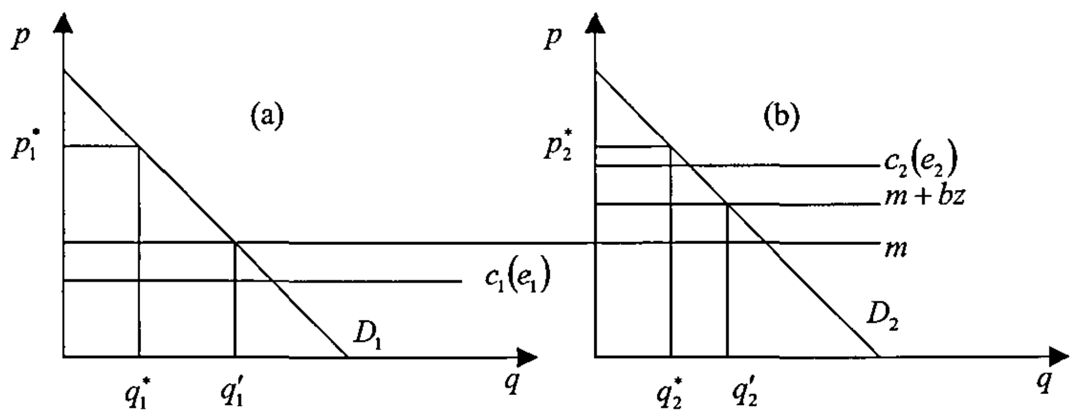

Figure 6.1.1 Yardstick price-cap model

The distribution business has been characterised by an average revenue price cap. One form of a fixed price contract suggested by Shleifer (1985) is where comparable regional monopolists have a price cap determined by the mean unit cost of others in the group. Figure 6.1.1 above illustrates the case where there are two firms, and firm one exhibits lower costs $c_1(e_1)$ when effort $[e_1]$ is applied compared to firm two who display higher costs $c_2(e_2)$, associated with effort $[e_2]$. Mean unit costs that determine the price cap are stated as $[m]$

If the regulator believes that firms differ because of exogenous characteristics of the operating environment $[z]$, the price cap is amended to $[m+bz]$. Firm one will be left with the residual claimant on the profits from reducing costs below the price cap. However firm two will need to exert costly effort in order to realise a profit, since $[c_2(e_2) > m+bz]$ Therefore if there are exogenous characteristics, firm two will attempt to use strategic behaviour to amend the price cap during a review process, so that it is able to limit the amount of costly effort required to achieve profitability If the firm is able to successfully change the impact of $[z]$ in it's favour, the first-best outcome does not materialise. This follows the arguments set out by Besanko and Sappington (1987).

REC	X factor	REC	X factor
Eastern	0.25	Norweb	1 40
East Midlands	1.25	Seeboard	0 75
London	0.00	Southern	0 65
Manweb	2.50	South Wales	2 50
Midlands	1.15	South Western	2 25
Northern	1.55	Yorkshire	1.30

Table 6.1.1 Initial regulation of electricity distribution

Table 6.1.1 shows that the initial choice of X factors was set to finance reinforcements and improvements to the network and to make the share prospectus attractive. Political pressures after the 1994 price control review reduced the reputation of the regulator This was because the price control was deemed to be overgenerous to the companies, since the market interpreted the announcement by delivering a soaring increase in the share price of the public electricity suppliers (PESs). The regulator reviewed the price control in 1995, which heralded tighter proposals based on an acceptable rate of return, only one year after the previous review This goes against the principle of a fixed regulatory period, and created uncertainty in the industry as a consequence. Uncertainty increases the risks for participants, so there is a danger that the regulator's actions increased the cost of capital for the distribution businesses

6.2 Theory of Data Envelopment Analysis and Total Factor Productivity

Efficiency and productivity calculations can be based on two types of approaches The first is a complex version of bottom-up studies, which involve looking at the different processes within a firm and areas for improvement. This will take considerable time and expense to understand how the full business operates, and the indicators only provide a measure of performance at a single point in time. The objective of this analysis is to review performance of the distribution industry since privatisation. Therefore a top-down approach is applied to the study, which has the advantage of using data for a number of businesses over a period of time, as well as looking at specific points in time

The study seeks to compare distribution businesses within England and Wales by determining which firms lie on the efficient frontier of the industry's production function This follows the arguments of Leibenstein (1966) who said that in the absence of external pressure and competition, managers would not pursue cost-reducing or efficiency-maximising behaviour. Farrell (1957) introduced the concept of an index of efficiency, based on ideas of Debreu (1951). A non-parametric methodology called Data Envelopment Analysis (DEA) is one way of measuring an index of efficiency

Distribution businesses that lie away from a best practice isoquant are judged inefficient under DEA. Pollitt (1997a) argues that a major practical advantage of the non-parametric approach is that "the actual costs incurred by the decision making unit (DMU) are not compared against some hypothetical least cost DMU but against best practice DMUs in the sample" (p 57) The models may also suggest cost-reducing changes based on policies actively implemented by lower cost DMUs If input prices were available, allocative efficiency could also be calculated, as derived by Fare, Grosskopf, and Logan (1985) A major theoretical advantage of DEA is that, unlike alternative methods such as stochastic frontier analysis, the investigation is not required to state a parametric functional form nor to impose the conditions for cost minimising behaviour in competitive markets in order to carry out the efficiency measurement. A drawback of this method is that inefficiency is assumed to account for all of this observed variation among firms

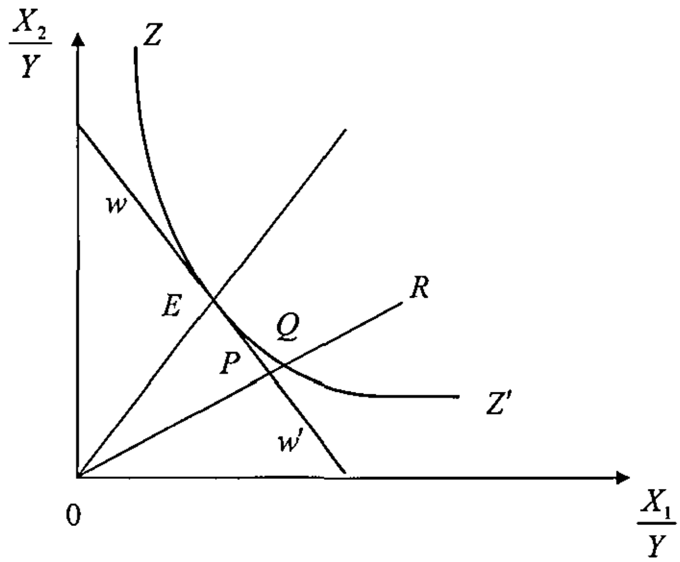

Figure 6.2.1 Farell efficiency model

Figure 6.2.1 above illustrates the basic ideas of DEA. The diagram represents a simplified version of the Farrell model, with two inputs and one output. If the axis is denoted as the input to output ratios then $[ZZ']$ will represent the unit isoquant (best practice) under constant returns to scale. Efficiency can be broken down into two parts Using figure 6.2.1:

$$\text{Technical efficiency} = \frac{OQ}{OR} \qquad (6\ 2.1)$$

$$\text{Allocative efficiency} = \frac{OP}{OQ} \qquad (6\ 2\ 2)$$

$$\text{Overall efficiency} = \frac{OP}{OR} \tag{6.2.3}$$

Input prices in practice are hard are to obtain for assembling an allocative efficiency index, so overall efficiency is difficult to measure Fare, Grosskopf, and Logan (1985) are one of the few authors to measure allocative efficiency in their study of the relative performance of publicly owned and privately owned electric utilities. Radial measures were used by Farrell (1957), to calculate efficiency. A ray is drawn from the origin to the point where the firm lies in the isoquant space. The distribution company at point E in figure 6.2.1 above is efficient in choosing the cost-minimising production process given the ratio of input prices presented by the slope of the line $[ww']$. In contrast the distribution company at point R is above the reference frontier $[ZZ']$. Subsequently the firm would have to reduce labour and capital inputs in proportion to $(1-e)$, to operate on a best practice frontier, where $[e]$ is an efficiency index.

Charnes, Cooper and Rhodes (1978) extended the work of Farrell (1957) by constructing a linear programming algorithm, which measured the technical efficiency of a multiple input-output individual decision making unit Apart from identifying best practice, DEA also allows for the provision of environmental variables, which a company is unable to control due to exogenous factors. In the distribution industry, service area and route km are two variables which can not be altered in the short term, and hence they may have a negative impact on performance.

Waddams-Price and Weyman-Jones (1996) in a study of gas distribution use customer density in each region as an environmental control variable. Customer density is given by the ratio of the number of customers to service area covered by the REC, and the conjecture is that as customer density increases, the network line length will decline. A smaller network will reduce line losses, costs, and improve the efficiency of the company operating the system. Similarly if market structure, defined as the ratio of industrial kWh to total kWh was used as a control variable, a higher ratio would increase the proportion of HV lines used across the region, culminating in a reduced demand for transformers. Provided there is a theoretical basis for their inclusion and an understanding of their likely role, environmental variables should be incorporated in this study

Figure 6 2.2 below shows six distribution companies, A, B, C, D, E. and F operating under constant returns to scale, and producing a single output $[y]$ using two inputs, $[x_1, x_2]$. The efficient frontier is defined by the highest ratio pairs of $\frac{y}{x_1}$ and $\frac{y}{x_2}$ Company A, B, and D are efficient, since they all lie on the frontier, while the remaining three companies are not characterised by best practice

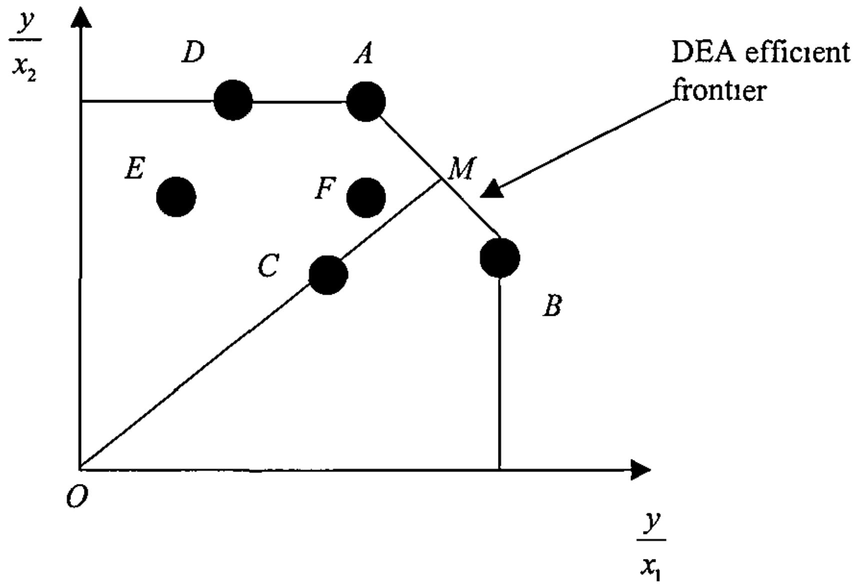

Figure 6.2.2 DEA efficient frontier

For example company C has a DEA efficiency of $\left[\frac{OC}{OM} < 1\right]$. In practice, modelling efficient frontiers will involve multiple inputs and multiple outputs, so the number of firms that lie on the frontier at any one time may be large. Furthermore in consultations with the regulator, a firm may suggest that a specific input-output ratio would take account of a peculiar characteristic which is only evident in it's region. Moreover it would argue that an allowance for this characteristic would shift it onto the unit isoquant.

Distribution studies therefore use the principles of DEA to calculate total factor productivity (TFP), which avoid these problems The Energy regulator will base the new price control starting in 2000/01 upon expectations of future productivity growth. An analysis of total factor productivity since privatisation is produced to assist in this review process Malmquist (1953) derived a quantity index for use in consumption analysis, but in recent years this method has been applied to production The methodology can be used to construct indices of productivity growth, which have desirable qualities, because they do not require input or output prices.

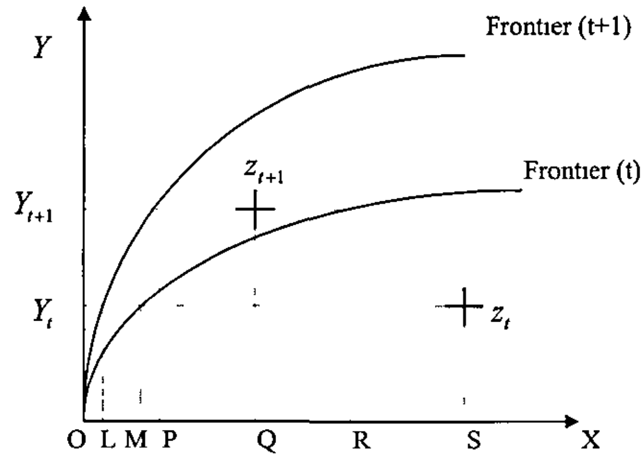

Figure 6.2.3 Malmquist index and productivity changes over time

A production frontier represents the level of output $[Y]$ that can be produced from a given level of input $[X]$. Over time the frontier shifts as a result of technological change and innovation. Figure 6.2.3 shows that the firm at $Z(t)$ in period (t) is inefficient because it lies below the frontier To move onto the efficient frontier for a given level of output $[Y(t)]$, inputs should be deflated by the horizontal distance ratio

$$\frac{OM}{OS} \qquad (6\ 2\ 4)$$

In the next period (t+1), inputs should be multiplied by the horizontal distance ratio:

$$\frac{OR}{OQ} \qquad (6.2.5)$$

to compare technical efficiency with the reference frontier (t) Subsequently the Malmquist index is calculated as

$$M = \frac{OR/OQ}{OM/OS} \tag{6.2 6}$$

Weyman-Jones and Waddams-Price (1996) decompose the Malmquist productivity index into a "catching-up effect" (MC) and a "frontier shift effect" (MF) This is attained, by re-scaling the Malmquist index by a factor $[OP/OQ]$, synonymous with the relative distance of $Z(t+1)$ from the frontier in period $[t+1]$.

$$M = \left(\frac{OP/OQ}{OM/OS}\right) \times \frac{OR}{OP} = MC \times MF \tag{6 2.7}$$

The catching-up effect explains how a firm has moved closer to the reference frontier $[t]$ in period $[t+1]$ relative to period $[t]$. The relative distance between the two frontiers measures the frontier shift effect Waddams-Price and Weyman-Jones (1996) adopted the base-weighted Malmquist index, which uses the initial year as the reference set for all subsequent comparisons. This is now deemed preferable to the chain-weighted index suggested by Fare et al (1994) following the arguments in Grifell-Tatje and Lovell (1996).

Use of the Malmquist index as a productivity growth measure does not depend on the assumption of efficiency variation amongst companies, and the original Caves, Christensen, and Diewert (1982) formulation is based on the assumption of productive efficiency. In addition, the use of the Malmquist index does not presuppose a particular estimation methodology. However by choosing the DEA based approach which can be performed without input prices, the investigator has the advantage of avoiding to specify both functional form and error distribution form. The only assumption needed in the existence of a production correspondence, states that each input vector maps to one or more output vectors

The procedure adopted uses a mathematical programming solution algorithm For each of the twelve RECs, $j = 1,.. ,12$, there are m inputs $\left(x_{ij}, i = 1, . \ , m\right)$ to make s outputs $\left(y_{rj}, r = 1,....,s\right)$. The observations for a single distribution company are represented by the vectors (x) and (y), while the industry reference set containing all twelve distribution companies are defined as (X) and (Y), using the weights, λ_j. These observations are split into two periods

$$A = \text{reference set period } t \tag{6.2.8}$$

$$B = \text{period } t+1 \tag{6.2.9}$$

A comparison of the REC in period $[t+1]$ with the reference technology set in period $[t]$ is denoted by (C) This enables the decomposition of the Malmquist index to be performed, as described in equation 6 2.7. The Malmquist index is based on the reciprocal of the input distance function, which is defined as the smallest ratio by which an input bundle can be multiplied and still be a member of the production possibility Waddams-Price and Weyman-Jones (1996) assert that it is "equivalent to the measure of technical efficiency proposed by Farrell (1957)" (p 32), and corresponds to figure 6.2 3. The three Farell efficiency indices computed are:

θ^A = relative efficiency of a firm in A compared to the frontier in A (6 2.10)

θ^B = relative efficiency of a firm in B compared to the frontier in B (6.2.11)

θ^C = relative efficiency of a firm in B compared to the frontier in A (6 2 12)

The following linear programmes are employed to solve these three indices

$$\min \theta^A \tag{6 2.13}$$

$$\text{s.t.} \quad X^A\lambda^A - \theta^A x^A \le 0$$

$$Y^A\lambda^A \geq y^A$$
$$\lambda^A \geq 0$$

$$\min\ \theta^B \tag{6 2 14}$$

$$\text{s t.}\quad X^B\lambda^B - \theta^B x^B \leq 0$$
$$Y^B\lambda^B \geq y^B$$
$$\lambda^B \geq 0$$

$$\min\ \theta^C \tag{6 2.15}$$

$$\text{s t}\quad X^A\lambda^C - \theta^C x^B \leq 0$$
$$Y^A\lambda^C \geq y^B$$
$$\lambda^C \geq 0$$

The Malmquist index that measures total factor productivity is re-written as

$$M = \frac{\theta^C}{\theta^A} = \frac{\theta^B}{\theta^A} \times \frac{\theta^C}{\theta^B} = MC \times MF \tag{6 2 16}$$

An improvement in productivity in period $[t+1]$ compared to period $[t]$ is denoted by $M > 1$ when the Malmquist index is based on the reciprocal of the input distance function, as described by equations 6 2.13 – 6 2.15. A decline in productivity on the other hand is demonstrated by an index value of $M < 1$. The reference set is based on the inputs and outputs of the industry players in 1991 for each year. Hence annual changes in productivity need to de derived before constructing an average productivity change index between 1990/91 and 1997/98. Fare, Grosskopf, Lindgren, and Roos (1992) defined a Malmquist productivity change index by constructing a geometric mean Applying these techniques to the study, average productivity change is constructed as:

$$r = 7\sqrt{(M_{92} \times M_{93} \times M_{94} \times M_{95} \times M_{96} \times M_{97} \times M_{98})} \qquad (6\ 2.17)$$

where M_{92} is the annual change in productivity for 1991/92

A linear program is constructed for measuring the relative efficiency using non-parametric frontier methods when environmental variables are incorporated in the model Using observed inputs $[X_1]$, outputs $[Y]$, and an environmental variable $[X_2]$, overall efficiency is calculated by solving the problem:

$$\min \theta \qquad (6\ 2.18)$$

$$\begin{aligned} \text{s t} \quad & X_1\lambda - \theta x_1 \leq 0 \\ & X_2\lambda = x_2 \\ & Y\lambda \geq y \end{aligned}$$

The second constraint encapsulates the environmental variable The unit is "only compared to a constructed frontier along which the value of the environmental variables are equal to those of the unit being analysed" (Pollitt 1997, p.65) Relative efficiency is adjusted for differences in the operating environment of the different utilities. In this way, regions with favourable population densities are prevented from appearing efficient on this assumption alone

Figure 6 2 4 below illustrates when a firm is not at the optimal long-run scale of operation as defined by Fare et al (1985) Assume that points $[E]$, $[S]$, and $[R]$ all represent the same level of output

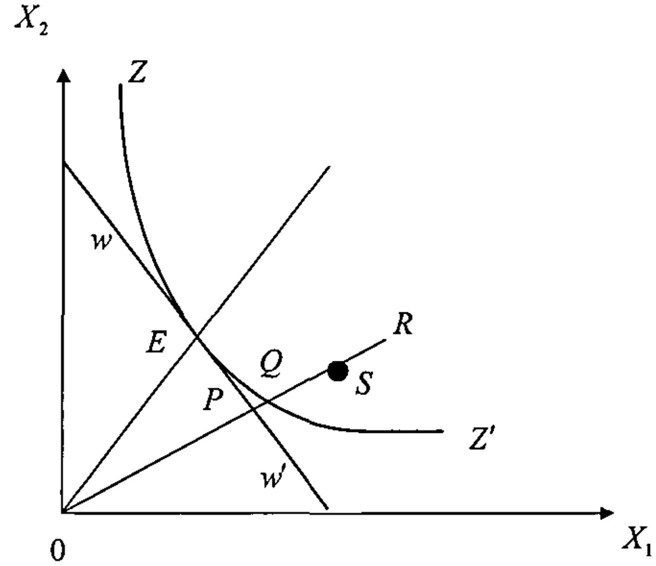

Figure 6.2.4 Scale efficiency model

The firm who is at point $[R]$ may experience non-constant returns to scale. Therefore it could produce its current output level with fewer inputs if the scale is adjusted to the optimal long-run constant returns to scale isoquant $[ZZ']$ which characterises a long-run competitive equilibrium. A further constraint is required when constant returns to scale are assumed·

$$\sum_i \lambda_i = 1 \tag{6.2.19}$$

Scale efficiency in figure 6.2 4 is defined as $\frac{OQ}{OS}$, while pure technical efficiency is $\frac{OS}{OR}$ For each period, scale efficiency is constructed as the "ratio of the distance function satisfying constant returns to scale to the distance function restricted to satisfy variable returns to scale" (Fare et al 1994, p 75) Hence the reciprocal input distance Malmquist index is further decomposed into:

$$M_i\left(x^{t+1}, y^{t+1}, x^t, y^t\right) = \Delta T \bullet \Delta E \bullet \Delta S \qquad (6\ 2\ 20)$$

where ΔT = technical change, ΔE = technical efficiency change and ΔS = scale change Using the notation of equation 6.2.16.

$$\Delta E \times \Delta S = \frac{\theta_V^B}{\theta_V^A} \bullet \left[\frac{\theta_C^B}{\theta_V^B} \bigg/ \frac{\theta_C^A}{\theta_V^A} \right] = \frac{\theta_C^B}{\theta_C^A} \qquad (6.2\ 21)$$

The literature on productivity indexes has been extended further by Fare et al (1997) They introduce the notion of biased technical change based on Hick's neutral technical change, which maintains the ratio of the marginal products under constant returns to scale. Technology exhibits *implicit Hick Output Neutrality* if technical change shifts all of the output vectors by the same amount i e. marginal rates of output transformation remain the same after technical change Therefore the technical change function only depends on time (t). Likewise technology exhibits *implicit Hicks Input Neutrality* if technical change shifts all the input vectors by the same amount i e. marginal rates of input substitution remain consistent after technical change is experienced If the technology has explicit joint input and output neutrality, Fare et al (1997) define technical change as:

$$\Delta T = \frac{\hat{A}(t+1)}{\hat{A}(t)} = \frac{\hat{B}(t+1)}{\hat{B}(t)} \qquad (6\ 2.22)$$

The reciprocal input distance Malmquist index is re-stated as

$$M_i = \frac{D_i^{t,t+1}}{D_i^{t,t}} = \left[\frac{D_i^{t,t+1}}{D_i^{t+1,t+1}} \right] \bullet \left[\frac{D_i^{t+1,t+1}}{D_i^{t,t}} \right] = MF \bullet MC \qquad (6.2.23)$$

where $[MF]$ defines the technical change, and $[MC]$ is the efficiency change. The distance function $\left[D_i^t\left(x^{t+1}, y^{t+1}\right) \equiv D_i^{t\ t+1}\right]$ measures the maximum proportional change in inputs required to make $\left[x^{t+1}, y^{t+1}\right]$ feasible in relation to the technology at $[t]$. Similarly the distance function $\left[D_i^t\left(x^t, y^t\right) \equiv D_i^{t,t}\right]$ measures the maximum proportional change in output required to make $\left[x^t, y^t\right]$ feasible in relation to the technology at $[t]$. The technical change index is broken up as.

$$MF = \frac{D_i^{t,t+1}}{D_i^{t+1,t+1}} = \left[\frac{D^{t,t}}{D^{t=1,t}} \right] \bullet \left[\frac{D_i^{t,t+1}}{D_i^{t+1,t+1}} \bigg/ \frac{D_i^{t,t}}{D_i^{t+1,t}} \right] = \Delta T \bullet Bias \qquad (6\ 2\ 24)$$

where the second term measures the bias of technical change. The bias index "measures the change in the relative distance between the two frontiers between the period $t+1$ observation and the period t observation" (Fare et al 1997, p 122). The bias index is decomposed further into an output bias and input bias as shown by equation 6 2 25

$$Bias = \left[\frac{D_i^t(x^{t+1}, y^{t+1})}{D_i^{t+1}(x^{t+1}, y^{t+1})} \Big/ \frac{D_i^t(x^{t+1}, y^t)}{D_i^{t+1}(x^{t+1}, y^t)}\right] \bullet \left[\frac{D_i^t(x^{t+1}, y^t)}{D_i^{t+1}(x^{t+1}, y^t)} \Big/ \frac{D_i^t(x^t, y^t)}{D_i^{t+1}(x^t, y^t)}\right]$$

$$= OB(y^t, x^{t+1}, y^{t+1}) \bullet IB(x^t, y^t, x^{t+1}) \qquad (6\ 2\ 25)$$

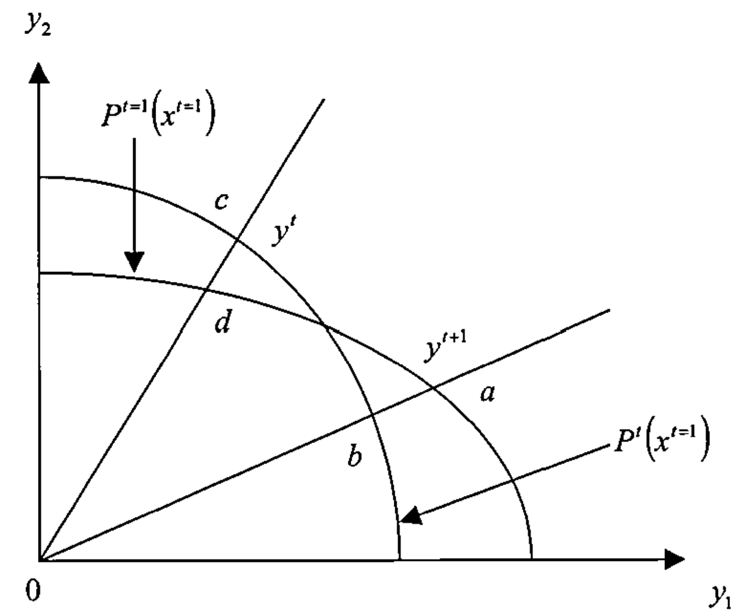

Figure 6.2.5 Output biased technical change

Figure 6 2 5 is based on a one input (x^{t+1}), two outputs (y_1, y_2) model, over two periods (t) and $(t+1)$. Two production frontiers have been drawn to represent the two time periods, $P^t(x^{t+1})$, and $P^{t+1}(x^{t+1})$ Fare et al (1997) express output bias as an index that measures the relative change in distance between the two frontiers as

$$OB = \frac{0b}{0a} \Big/ \frac{0c}{0d} \qquad (6\ 2\ 26)$$

If there is no output bias, then the ratio will equal unity. Fare et al (1997) state two stringent conditions where the output bias index makes no contribution to productivity change

I $\left[y^{t+1} = \lambda y^{t}, \lambda > 0\right]$

II. technology exhibits implicit Hicks output-neutral technical change.

The first ratio measures the shift in technology between period $[t]$ and $[t+1]$ but at the input level observed in period $[t+1]$ The second ratio in the input bias measures the shift in technology between period $[t]$ and $[t+1]$ evaluated as the input-output vector observed in period $[t]$. The conditions for input bias neutrality are

I $\left[x^{t+1} = x^{t}\right]$

II $\left[x^{t+1} = \lambda x^{t}, \lambda > 0\right]$ and technology exhibits constant returns to scale

III Implicit Hicks input-neutral technical change

6.3 Regression Strategies

To investigate the sources of productivity growth, the index of total factor productivity (TFP) for the twelve distribution companies is regressed against variables that may influence the rate of growth in a log-linear functional form. This does not require the use of limited dependent variables in contrast to a linear functional form where the TFP index will have to meet the condition of $TFP \geq 0$.

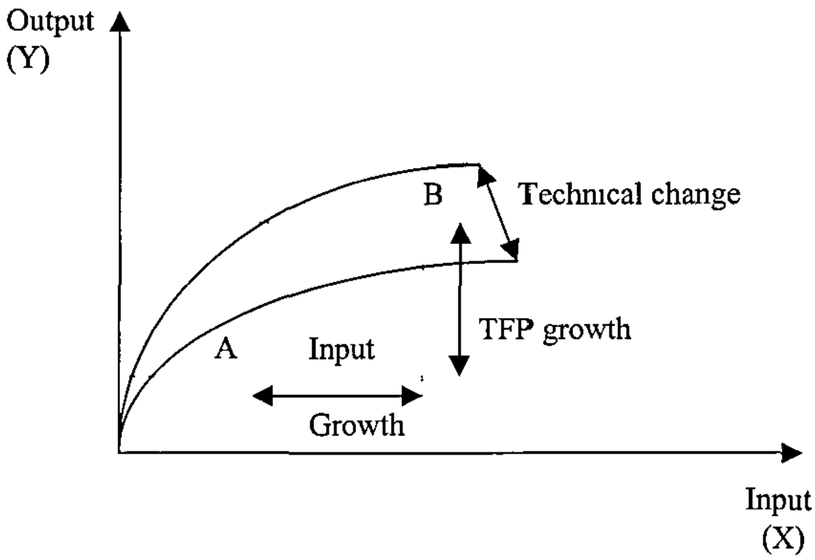

Figure 6.3.1 Endogenous growth model

Endogenous growth theory says that TFP growth depends on the variables in the model and the system In the context of this study they are the economic institutions (timing of the regulatory price control review), input scale and output scale The data set consists of time series $[t]$ and cross-sectional properties $[n]$, so a panel regression is constructed to investigate what factors contribute to TFP growth, and to test for a structural break after the second distribution price control. The number of observations in the panel is $[t \times n = 8 \times 12 = 96]$. Figure 6 3.1 describes the dis-aggregated TFP growth function, where output growth is the summation of input growth and TFP growth

The obvious generalisation of the constant intercept and slope model for panel data is to "introduce dummy variables to account for the effects of those omitted variables that are specific to individual cross-sectional units but stay constant over time, and the effects are specific to each time period but are the same for all cross-sectional units" (Hsiao 1989, p 29).

The model for each distribution company $[i]$ is expressed as:

$$Y_{it} = \alpha_i^* + \beta' x_{it} + u_{it} \qquad (6\ 3\ 1)$$

where $[\beta']$ is a $(1 \times K)$ vector of constants, $[\alpha_i^{*}]$ is a (1×1) scalar constant representing the effects of those variables peculiar to a distribution company, and $[u_{it}]$ explains the effects of omitted variables that are peculiar to individual distribution companies and time periods with the characteristics

$$E(u_i) = 0, E(u_i u_i') = \sigma_u^2, E(u_i u_j') = 0 \text{ if } i \neq j \tag{6 3 2}$$

An advantage of panel data is that if the effects of omitted variables are constant for a distribution company through time, this problem is eliminated by using dummy variables to capture the effects of individual-invariant and time-invariant variables Panel data also has many more degrees of freedom and information, which helps to reduce the problems of multicollinearity.

Tests by Brown and Forsythe (1974) and Levine (1960) are used for identifying cross-sectional heteroscedasticity. Feasible generalised-least squares (FGLS) is applied to the panel regression when the structure of the residuals displays these properties. The variance-covariance matrix of $[u]$ is given by.

$$V(u) = E\begin{bmatrix} u_1u_1' & u_1u_2' & \cdot & \cdot & u_1u_n' \\ u_2u_1' & u_2u_2' & \cdots & \cdot & u_2u_n' \\ \cdot & & \ddots & & \vdots \\ \vdots & & & \ddots & \vdots \\ u_nu_1' & u_nu_2' & \cdots & \cdot\cdot & u_nu_n' \end{bmatrix} \tag{6 3.3}$$

where there are $[n]$ distribution companies in the cross-section, and $[t]$ time periods, and $E(u_i u_j')$ is a $(t \times t)$ matrix If the errors are contemporaneously uncorrelated:

$$E(u_i u_j') = \sigma_{ij} I \quad \text{if } i = j \tag{6 3.4}$$

and is zero otherwise so·

$$V = diag(\sigma_{11}, \sigma_{22}, \quad , \sigma_{nn}) \otimes I_t \tag{6 3.5}$$

where $[\otimes]$ is the Kronecker product The weighted-least squares estimator which yields a consistent estimator of $[V]$ is given by

$$\hat{\beta}_{GLS} = \left(X'\hat{V}^{-1}X\right)^{-1} X'\hat{V}^{-1}Y \tag{6.3.6}$$

where the elements of diagonal matrix, $\hat{V}^{-1} = diag(1/s_{11}, 1/s_{22}, \ldots, 1/s_{nn}) \otimes I_t$, and $[s_{ii}]$ is the residual variance estimator

Cross correlograms are used to identify contemporaneous correlation in the panel regression. If the cross correlations fall within the approximate two standard error bounds computed as $\pm 2/\sqrt{T}$, then cross correlation is not significantly different from zero at approximately the 5% level of significance. If the null hypothesis of no cross correlations is rejected at the 5% level of significance, then seemingly unrelated regressions are used for constructing a feasible generalised least squares estimator. A Wald test is used to examine whether a model is significantly different following the deletion of a variable If the null hypothesis of no significance is not rejected at the 5% level, then the explanatory variable is removed from the regression

6.4 Data employed in the study

Real Operating expenditure is used as a proxy for labour, and is defined as revenue minus operating profit, current cost depreciation, and exceptional items. Data was collected from the regulatory accounts of the RECs associated with the distribution business for constructing operational expenditure This is deflated by a producer price index obtained from the *Office of National Statistics Economic Trends*. The regulatory accounts also include data on tangible fixed assets Costs allocated to the distribution system at the 31st March of each year provide a value of the capital stock This is transformed into real terms by deflating by the gross investment deflator (GID), which is calculated from *Economic Trends* as:

$$GID = \frac{\text{gross fixed capital formation (current prices)}}{\text{gross fixed capital formation (constant prices)}} \tag{6.4.1}$$

The annual Distribution and Transmission System Performance reports from OFFER contain data on area size, customer numbers, overhead circuit, underground circuit, number of transformers in commission, and aggregate capacity of the transformers The Electricity Association provided data on the number of units distributed (GWh), and maximum demand. Condition 9 reports submitted by the distribution business to the regulator contain information on the quality of supply variables· supply interruptions per 100 customers, customer minutes lost per customer, and the number of interruptions per 100 customers not repaired within three hours.

6.5 The Models tested in the study

The first consideration for designing models is to decide what parts of the distribution business can be categorised by inputs and outputs. Weyman-Jones (1996) in a review of yardstick comparisons among distribution companies describes one type of model, represented by table 6.5.1a.

Inputs	Outputs
Manpower	Domestic sales
Network size	Commercial sales
Transformers	Industrial sales
	Maximum demand

Tables 6.5.1a Review of studies in the distribution industry

Inputs and outputs chosen in this model follow the empirical evidence on cost studies in electricity supply The type of load operation will have different impacts on costs, and this is represented by the different categories of sales and maximum demand. The choice of inputs reflects the use of labour and capital in the distribution industry.

Table 6 5 1b below reflects upon the electricity distribution empirical study by Neuberg (1977). Neuberg includes customer numbers as an output because distribution companies provide a service to those customers. Network size and transformer capacity is chosen as environmental variables so relative efficiency could be measured after adjusting for explicit differences in the operating environment of each REC

Inputs	Outputs	Environmental variables
Manpower	Number of customers	Network size Transformers Total sales Maximum demand Density Industrial share

Tables 6.5.1b Review of studies in the distribution industry

A high efficiency score is attained when inputs are minimised and outputs are maximised in these models. In traditional producer theory there are two inputs, labour and capital Following the two broad models in tables 6 5.1a and 6 5.1b, model one incorporates three inputs. This consists of operating expenditure (OPEX), and the physical capital characteristics of the distribution network reflecting the total length of the distribution network in each of the REC's areas (NET), and the transformer capacity of each REC (CAP)

Expansion of the network in one year will lead to relative inefficiency However if this is justified to meet economic expansion, then in the following years this will be judged as an efficient investment This helps to explain in practical terms why the study concentrates on productivity growth over a period of time, rather than a snapshot of efficiency in one period The distribution models have traditionally specified outputs as electricity units distributed across the network (UNITS), the number of customers served by each REC (CUST), and the maximum demand strain placed on each network (MAXD) All the models analysed in this study follows this approach

The second model replaces the two physical capital characteristics with a value for capital stock (KSTOCK). The advantage of comparing models is that when they produce similar conclusions the robustness of the study will improve. Furthermore it makes it easier for the regulator to adopt a yardstick approach, confident that each company has been treated fairly in the review process.

Table 6 5 2 below displays three quality variables to assess their impact on the performance of the distribution businesses using a customer-weighted average for England and Wales. Security of supply (SECUR) defines the number of interruptions per 100 customers; availability of supply (AVAIL) denotes minutes lost per customer, and FAULTS states the number of interruptions not restored after three hours A sub-standard quality of supply is viewed as a welfare loss to customers

Year	SECUR	AVAIL	FAULTS
1991	113	239	20
1992	86	101	9
1993	93	100	10
1994	84	93	9
1995	88	96	9
1996	90	92	9
1997	90	83	8
1998	87	85	8

Table 6.5.2 Quality of supply

The price control after privatisation allowed for higher revenues to be collected from customers to reinforce the network Progress in the quality of supply was greatest during the first year after privatisation, which coincided with very large increases in capital stock. The present price control includes a capital expenditure allowance of £2.30 per customer per annum at today's prices, for quality of supply measures Ofgem (1999d) have stated that one of the objectives is for customers to "receive appropriate levels of quality of supply, with improvement as necessary, at minimum cost" (p.61). If company targets for 1999/2000 are met, reductions in the number of interruptions and customer minutes lost will be in the range of 10-15% from 1994/95 levels. It is the view of Ofgem that most companies will achieve this target. Models three to five introduce quality of supply to the study of performance to judge whether this has a significant impact on productivity growth.

Customer density (CUSDEN) is used as an environmental variable in model six under the assumption of varying returns to scale Figures were not publicly available for industrial kWh distributed by the RECs over the entire sample period, so a model incorporating market structure as a second environmental variable was not tested

Model seven introduces the concepts of technical bias with real OPEX and capital stock chosen as the two input variables Table 6.5.3 identifies the make-up of all the models tested in the study. The notation is I = inputs; EV = environmental variable, CRS = constant returns to scale; VRS = variable returns to scale; Q = outputs

Model	Description
1	I = OPEX, NET, CAP; Q; CRS and VRS
2	I = OPEX, KSTOCK, Q; CRS
3a	I = OPEX, NET, CAP, SECUR; Q, CRS
3b	I = OPEX, KSTOCK, SECUR, Q, CRS
4a	I = OPEX, NET, CAP, AVAIL; Q, CRS
4b	I = OPEX, KSTOCK, AVAIL, Q, CRS
5a	I = OPEX, NET, CAP, FAULT, Q, CRS
5b	I = OPEX, KSTOCK, FAULT; Q, CRS
6	I = OPEX, KSTOCK; EV=CUSDEN, Q, VRS
7	I = OPEX, KSTOCK, Q; CRS (technical bias)

Table 6.5.3 Description of models

6.6 Productivity results

6.6.1 Model one

Figure 6 6.1.1 below illustrates annual average productivity growth between 1990/91 and 1997/98 for the twelve England and Wales RECs. Average productivity growth for the industry was 6 3% per annum, although there were wide variations among the distribution companies. Eastern, Seeboard, and Southern were the leading performing companies over the sample period, with productivity growth of over 8% per annum East Midlands, London, SWEB, and Yorkshire were defined as middle-ranking RECs from this study averaging between 6.1% and 7% per annum. The results further imply that Manweb, Midlands, Northern, Norweb, and SWALEC achieved sub-standard productivity growth of between 3.6% and 5.2% per annum.

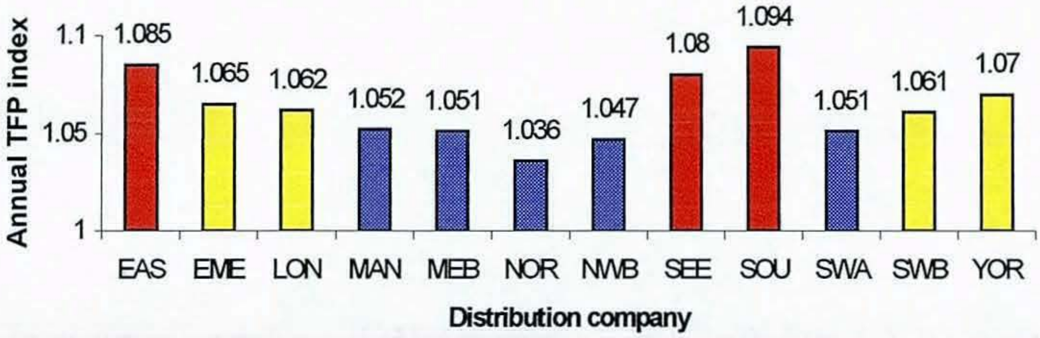

Figure 6.6.1.1 Annual TFP growth between 1990/91 and 1997/98

The pattern of productivity growth is of interest, as it would be useful to understand whether the leading performing RECs achieve their status through similar or contrasting policies. Table 6.6.1.1 describes the evolution of annual total factor productivity, and suggests that performance was achieved through dissimilar policies. Between 1990/91 and 1993/94 Eastern's annual productivity gains were significantly higher than Seeboard and Southern.

REC	1992	1993	1994	1995	1996	1997	1998
Eastern	6.6	2.5	14.4	-0.5	18.8	15.8	3.7
Seeboard	0.8	4.3	1.7	0.1	10.0	42.8	2.1
Southern	1.6	1.7	1.3	21.0	17.7	21.0	3.8

Table 6.6.1.1 Productivity growth for the leading companies

Although Eastern continues to make considerable efficiency gains between 1995/96 and 1997/98, Southern achieves a superior performance over the entire sample range. Low productivity growth is experienced until 1994/95 when a change appears to have taken place. Productivity then increases by over 20% in 1994/95 and 1996/97, and by nearly 18% in 1995/96. Seeboard is in the leading cluster of RECs aided exclusively by an exceptionally high productivity growth rate of 42.8% in 1996/97 compared to the previous year. The explanation for these different productivity paths will be aided by panel regressions, which are discussed later in this section.

Table 6.6.1.2 identifies different patterns of productivity growth over the sample period for the middle-ranking cluster of RECs. East Midlands and London electricity achieve similar productivity growth rates in each of the years assessed in the study. Prior to 1994/95, South Western's productivity regressed in contrast to East Midlands and London. Although Yorkshire also regressed in 1992/93 and 1993/94, the net effect since privatisation was of higher productivity.

REC	1992	1993	1994	1995	1996	1997	1998
EME	9.9	6.8	1.2	0.7	17.8	10.1	0.5
London	7.4	5.5	2.7	2.1	11.1	12.4	2.9
SWEB	-9.4	-4.4	-2.9	1.6	16.2	40.3	8.3
Yorkshire	1.9	-0.4	-1.2	13.8	19.7	5.6	11.3

Table 6.6.1.2 Productivity growth for middle-ranking RECs

The significance of the results in tables 6.6.1.1 and 6.6.1.2 is that there appears to be a structural break in performance after 1994/95. This is why the panel regressions are testing for the hypothesis of higher productivity growth after the second distribution price control, which these results lend support to. Average productivity for South Western is lower than Seeboard, but both attain significant improvements in productivity in 1996/97. Therefore it will be interesting to discover whether there is a common factor that is causing significantly higher growth in this particular year.

REC	1992	1993	1994	1995	1996	1997	1998
Manweb	6.7	2.7	-3.7	17.5	-4.3	20.7	-0.5
Midland	1.3	4.5	8.0	-2.5	20.1	1.1	4.3
Northern	-0.4	1.1	-4.0	21.2	2.0	3.2	3.6
Norweb	-4.0	7.4	-1.6	-1.2	18.4	6.9	8.9
SWALEC	1.0	2.3	0.7	0.8	18.6	9.6	3.7

Table 6.6.1.3 Productivity growth for under-performing RECs

The results in table 6.6.1.3 infer that Midland electricity attains the fourth highest productivity growth rate between 1990/91 and 1993/94. However it is clear that one of the reasons for the change in ranking when performance is assessed between 1990/91 and 1997/98 is that the Midland has the worst performance in the second half of this sample set. The panel regression may be able to identify why this has happened, but clearly something has affected the results in 1996/97 because productivity is only 1.1% higher compared to the previous year.

Manweb and SWALEC have identical annual productivity growth of 5.1%, but whereas SWALEC continue to improve performance year on year, productivity regress is apparent in three years for Manweb. However Northern electricity fail to make productivity gains in the first years after privatisation, since it is not until 1994/95 that productivity growth is recorded. After this large one-off increase, consistently low productivity improvements are made between 1995/96 and 1997/98.

Figure 6.6.1.2 presents annual productivity growth over two sub-sample periods defined as 1990/91 to 1993/94 and 1994/95 to 1997/98. The general trend among distribution companies is for much faster productivity growth after 1994. Pollitt (1997b) suggests that government protection from takeover of utilities after privatisation in the UK most probably reduced the pressure on distribution companies to remove costs, and thus helps to explain this eventuality.

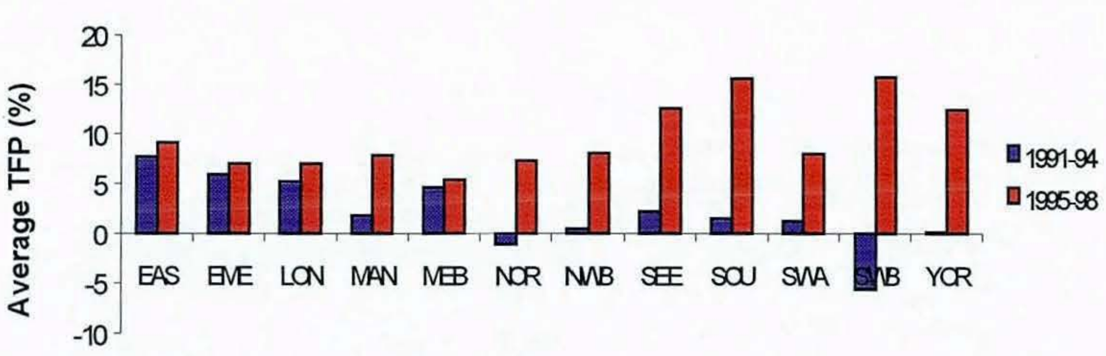

Figure 6.6.1.2 Productivity growth over different time periods for model 1

Pollitt (1997b) uses Manweb as an example of how distribution companies were able to reduce costs considerably after the government sold their golden share in these companies. Prior to privatisation, Manweb had 5,551 registered employees. In 1994/95 this had fallen slightly to 4,582, but after the takeover by Scottish Power there were only 2,975 in 1996/97. A downward trend in real OPEX from 1995/96 would symbolise how distribution companies slim-lined their workforce, and thus improve shareholder value either as an independent company or as an American holding company.

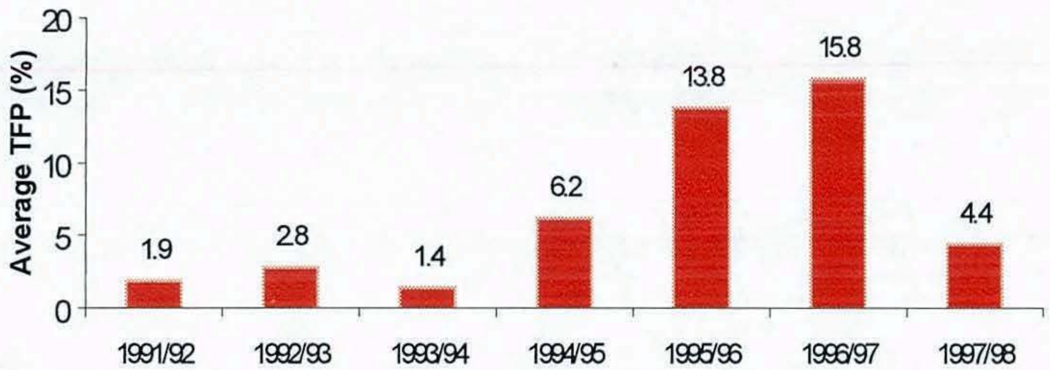

Figure 6.6.1.3 Annual total factor productivity for the industry

Figure 6.6.1.3 confirms that the highest rate of productivity growth occurred after the regulatory price controls, with growth above approaching 16% in 1996/97. Incentives to continue to improve efficiency throughout a price control may be blunted by strategic behaviour as companies attempt to persuade the regulator that the large gains made in the early years during a current price control were a one-off event and could not be repeated. This is explained by the fact that the closer efficiency gains are made to a new price control review, the shorter the period for retaining these gains. In contrast Ofwat (1999) has allowed efficiency gains to be retained for a full five years whenever this takes place during the regulatory contract.

Productivity growth in the privatised electricity distribution industry is distinguished between innovation and diffusion of technology and best practice. It is immediately apparent from figure 6.6.1.4 below that all of the observed productivity growth is associated with the industry moving onto a higher frontier and in contrast, none of the productivity growth is due to improvements in efficiency.

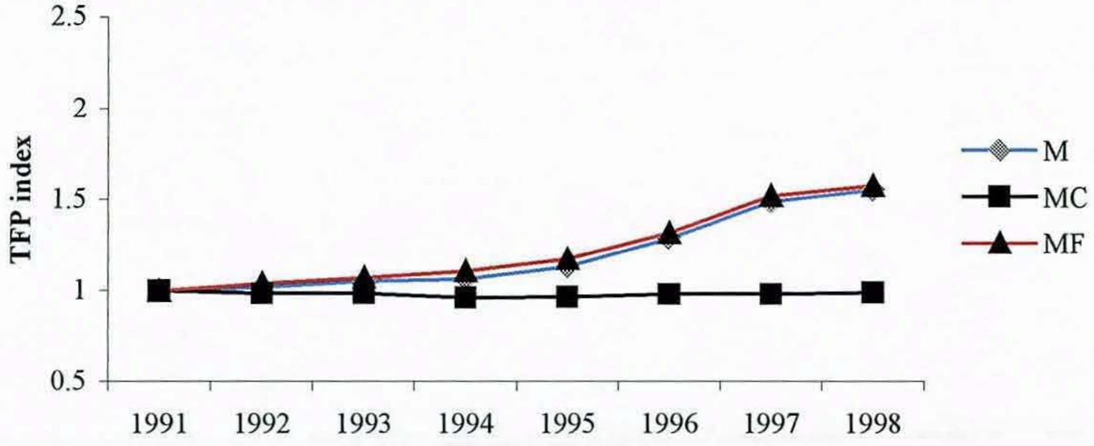

Figure 6.6.1.4 Malmquist indices for the average distribution company

Table 6.6.1.4 shows that the distribution of efficiency in the distribution business is dominated by technical change. Furthermore scale efficiency has no role for most of the distribution businesses. This implies that distribution companies are operating at the long-run competitive isoquant.

REC	M	MF	MC (CRS)	MC (VRS)	Scale efficiency change
EAS	1.085	1.085	1.000	1.000	1.000
EME	1.065	1.069	0.996	0.996	1.000
LON	1.062	1.062	1.000	1.000	1.000
MAN	1.052	1.052	1.000	1.000	1.000
MEB	1.051	1.051	1.000	1.000	1.000
NOR	1.036	1.036	1.000	1.000	1.000
NWB	1.047	1.065	0.983	0.983	1.001
SEE	1.080	1.080	1.000	1.000	1.000
SOU	1.094	1.094	1.000	1.000	1.000
SWA	1.051	1.048	1.002	1.000	1.002
SWB	1.061	1.076	0.985	1.002	0.983
YOR	1.070	1.070	1.000	1.000	1.000

Table 6.6.1.4 Decomposition of Malmquist index with scale effects

Scale efficiency is derived in the following way:

$$\text{Scale efficiency} = \frac{\theta_c^B / \theta_v^B}{\theta_c^A / \theta_v^A} = \frac{MC(crs)}{MC(vrs)} \qquad (6.6.1.1)$$

The relative importance of the frontier shift effect suggests that managers are placing more emphasis on maximising profits due to a clearer incentive based regulatory system, leading to considerable improvements in technical efficiency since deregulation. However the different regional distribution companies are not experiencing the rivalry pressures that exist from *yardstick* competition.

6.6.2 Results of the other models used in the analysis

REC	2	3a	3b	4a	4b	5a	5b	6
EAS	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
EME	5.9	6.5	5.9	6.8	6.2	6.8	6.2	6.4
LON	8.3	6.7	4.9	6.8	4.1	6.6	8.3	9.1
MAN	5.2	5.3	5.3	5.7	5.7	5.6	5.6	5.4
MEB	6.1	5.1	6.1	5.1	6.1	5.1	6.1	6.2
NOR	2.1	3.6	2.1	3.7	2.0	3.7	2.1	2.6
NWB	5.4	4.5	5.2	4.7	5.4	4.7	5.4	5.0
SEE	8.0	8.0	8.0	8.0	8.0	8.0	8.0	9.0
SOU	9.4	9.4	9.4	9.5	9.5	9.6	9.6	9.7
SWA	6.2	5.1	6.2	5.1	6.2	5.1	6.2	7.1
SWB	5.7	6.1	5.7	6.1	5.7	6.1	5.7	7.4
YOR	7.5	7.0	7.5	7.6	7.9	7.6	8.0	7.9
Frontier Effect	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Catch-up effect	No	No	No	No	No	No	No	No
Average	6.5	6.3	6.2	6.5	6.3	6.5	6.7	7.0

Table 6.6.2.1 Malmquist productivity growth rates for models 2-6

Table 6.6.2.1 highlights the variation in productivity growth caused by using different input and output variables in each model. Taking an average of all the models, a conclusion that can be drawn is that the industry has produced productivity growth at an annual rate of 6.5% since privatisation. Each of the models will now be examined in more detail.

Model two has broadly similar results to model 1, although there are some notable exceptions. Figure 6.6.2.1 compares the TFP index for model one and two to ascertain which years were responsible for London electricity's productivity increasing from 6.2% to 8.3% per annum. London electricity lies on a similar path of productivity growth between 1990/91 and 1994/95. However there appears to be a break thereafter, with model two exhibiting faster TFP growth between 1995-97. 1996/97.

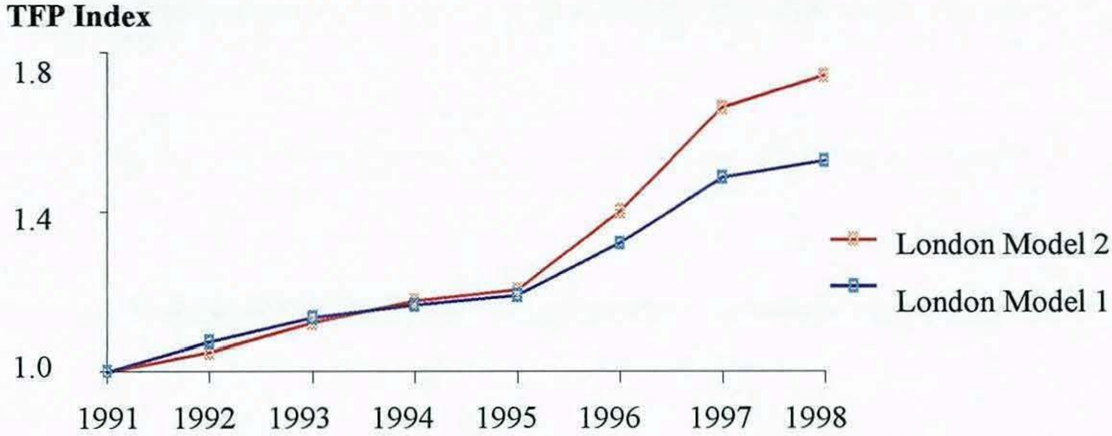

Figure 6.6.2.1 TFP index for London electricity

Midland and SWALEC now occupy middle-ranking status compared to model one when capital stock replaces physical capital in the derivation of efficiency. SWALEC's performance in particular is affected by this change with significant fluctuations from model one's TFP index. Figure 6.6.2.2 below shows that productivity actually regressed in the first year after privatisation, and the TFP index path was below that of model two until 1995/96, when productivity soared by 34% in one year. SWALEC maintained similar productivity growth compared to model one in the remaining years of the study. Regression analysis will test the hypothesis that capital stock is a significant determinant of total factor productivity, as this result implies for SWALEC.

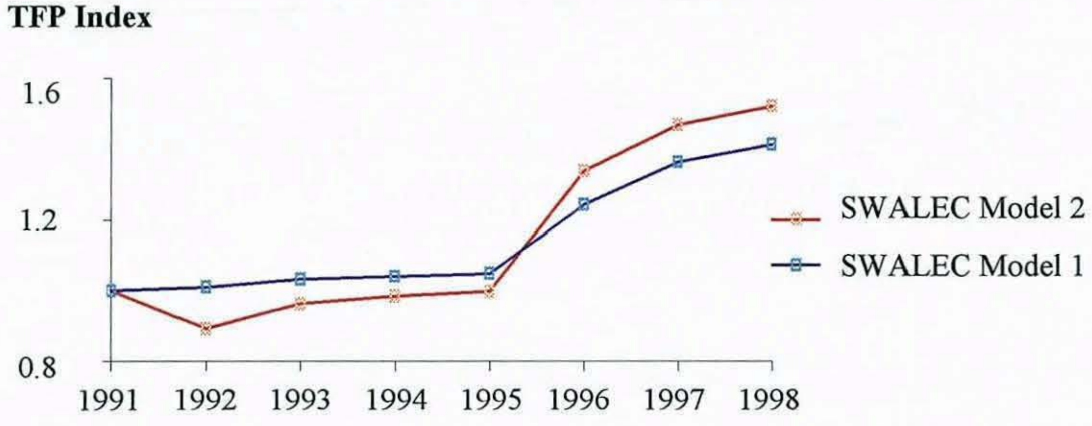

Figure 6.6.2.2 TFP index for SWALEC

London electricity is the only distribution company where the annual TFP index is higher in model 3a compared to model one. However when capital stock replaces physical capital, her productivity slumps to 4.9% per annum. Figure 6.6.2.3 shows that the last two years of the study were responsible for the deterioration in performance. Productivity falls by 2.1% in 1996/97, and then only improves by 2.2% in the following year. Model two in contrast continues with uninterrupted productivity gains during the final two years, with 19% growth in 1996/97 and 4.8% in the following year. Regression analysis will determine whether there are important policy implications associated with targeting resources.

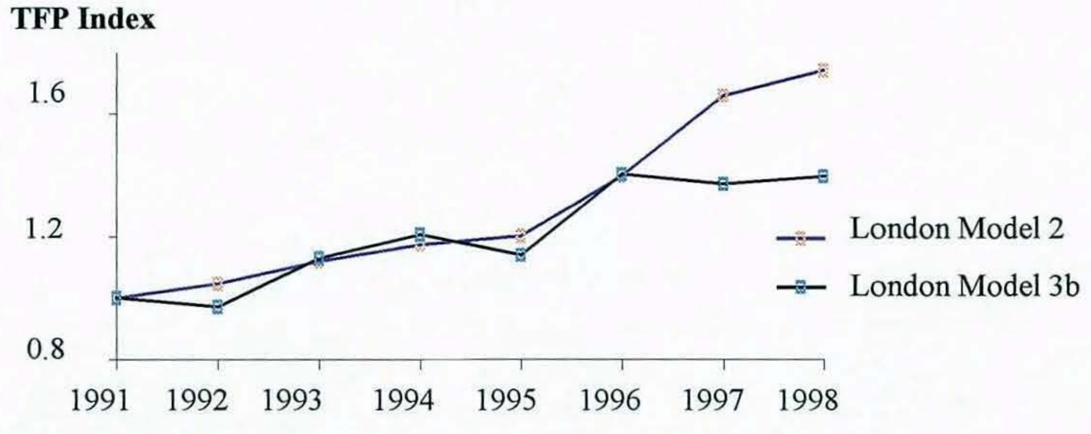

Figure 6.6.2.3 TFP index for model 2 and model 3b

When customer minutes lost are used as the quality variable in model 4b, London's average annual productivity slowed further to 4.1%. The effects for other distribution companies are relatively benign. However Yorkshire and Manweb both attained marginally higher productivity growth in models 4a and 4b

Table 6 6 2.2 below explains that Yorkshire electricity have made considerable effort to reduce the length of time customers are disconnected from their electricity supply In 1990/91 they had the fifth highest incidence of interruptions not restored within three hours. This had been turned around in the following year, resulting in the smallest number of interruptions not restored within three hours. Yorkshire maintained this high quality of service throughout the remaining sample period and consequently increased productivity growth to 8% in model 5b This result pushes the company into the leading cluster of RECs, alongside Eastern, London, Seeboard, and Southern. A number of other distribution companies notably East Midlands and Manweb have also produced higher rates of productivity as a result of reducing the number of interruptions not restored after three hours. Although Midlands and Northern have made great strides in increasing the speed at which faults are repaired, they have not improved their overall productivity.

REC	1991	1992	1993	1994	1995	1996	1997	1998
EAS	7	5	10	6	7	6	6	5
EME	59	7	9	10	12	9	7	7
LON	9	10	8	6	8	7	7	7
MAN	19	10	11	13	9	9	8	9
MEB	30	9	13	15	13	16	11	11
NOR	26	9	10	12	10	10	10	8
NWB	11	8	7	5	5	6	6	10
SEE	8	8	12	7	8	7	9	9
SOU	9	9	8	7	8	8	7	5
SWA	32	25	18	22	22	28	22	22
SWB	18	16	19	18	15	12	9	13
YOR	20	4	5	5	6	4	4	5

Table 6.6.2.2 Number of interruptions not restored within 3 hours

SWALEC and SWEB both operate in predominantly rural areas. When customer density is applied as an environmental control variable they both increase average productivity growth to 7.1% and 7.4% respectfully as shown by table 6 6.2.3. The objective of the control variable is to take account for the fact that customer density is not a variable that can be influenced by the company, and as such productivity linked to a non-controllable variable would not be a fair reflection on the true outcome Moreover it is easier to deliver the outputs in the London licence because of the urban nature of the location Productivity growth is explained by a frontier shift and there is no evidence of scale efficiency, implying that distribution companies are operating at the long-run competitive equilibrium isoquant as implied by model one If customer density is a significant variable in the panel regression, managers of SWALEC and SWEB could not argue that their performance is affected by topography factors

REC	M	MC (CRS)	MC (VRS)	MF	scale efficiency
EAS	1 085	1.000	1 000	1.085	1.000
EME	1.064	1.006	1 000	1 054	1 006
LON	1.091	1 000	1.000	1 091	1 000
MAN	1.054	0 981	0.993	1.073	0.987
MEB	1 062	0 977	0 977	1.086	1.000
NOR	1 026	0 981	0 993	1.040	0.988
NWB	1 050	0.968	0 969	1.088	0.999
SEE	1 090	1.000	1.000	1.084	1 000
SOU	1.097	1 000	1 000	1 094	1 000
SWA	1 071	0 990	1 000	1.072	0.990
SWB	1.074	1 006	1.000	1.051	1.006
YOR	1.079	0.995	0.997	1.080	0 998

Table 6.6.2.3 Scale efficiency under model 6

Following the procedures by Fare et al (1997), input bias is close to unitary according to table 6 6 2 4 below for all of the RECs, so technology exhibits constant returns to scale Therefore deregulation and regulatory reforms have not induced significant change in the input mix.

REC	ΔT	Input bias	Output bias
EAS	1.003	1 001	1.081
EME	0 997	1 001	1.061
LON	1.000	1 004	1 089
MAN	0.999	1 000	1 074
MEB	0 999	1.003	1 084
NOR	0 997	1.000	1 044
NWB	1 007	1.000	1 083
SEE	0.989	1.006	1 085
SOU	0 994	1.010	1 089
SWA	1 004	1.002	1 079
SWB	0 999	0.997	1 072
YOR	0 999	1.000	1 081

Table 6.6.2.4 Technical Bias in model 7

The model nevertheless displays an output bias of technical change, so technical improvement is accompanied by a change in the output mix Since the number of customers supplied by distribution companies has remained largely unchanged between 1990/91 and 1997/98, changes in the output mix are related to the composition of electricity units distributed and maximum demand. Growth in electricity units distributed is greater than for maximum demand. This is quite significant because it suggests that the companies are using tariff signals to improve load factors

6.7 Panel Regression results

Three panel regressions were constructed based on the TFP index for model two The first panel regresses log(TFP) against operating expenditure (OPEX), capital stock (KSTOCK), units distributed (GWH), maximum demand (MAXD), regulatory timing dummy (REG), customer density (CUSDEN), customer minutes lost (AVAIL), number of supply interruptions (SECUR), and the number of interruptions not restored after three hours (FAULT). After using generalised least squares to remove the effects of heteroscedasticity, the best model is reported in table 6.7.1 below.

Variable	Coefficient	t-Statistic
OPEX	-0 003	-23.4
KSTOCK	-0 00002	-3.4
GWH	0 00001	2.7
MAXD	0 00001	0.96
REG	0 015	2 4
CUSDEN	-0 00003	-0 18
AVAIL	-0 00001	-0.29
SECUR	-0 0002	-2 0
FAULT	0 0007	0.95

Table 6.7.1 Generalised least squares fixed-effects panel regression

Real operating expenditure, capital stock, and the number of supply interruptions are negatively correlated with $\log(\mathrm{TFP})$ whereas the number of electricity units distributed (GWh) is positively correlated with $\log(\mathrm{TFP})$ at the 5% level of significance. Furthermore the results support the view that there is a structural break in the TFP index after the second distribution price control, because the TFP index is 3.2% higher *ceteri paribus*. This also provides statistical support to comments made by Pollitt (1997b) which suggested that the government's holding of golden shares until 1995 in the newly privatised electricity companies acted as a constraint on productivity, because the threat of takeover was not prominent

Variable	Coefficient	t-Statistic
OPEX	-0.003	-32.1
KSTOCK	-0.00002	-5.1
GDP	0.00003	8.0
REG	0 013	4.4
SECUR	-0 0001	-2 7

Table 6.7.2 Generalised least squares fixed-effects panel regression

The result of the second panel regression in table 6.7.2 shows that a high level of regional economic performance will contribute positively to productivity growth

Electricity units distributed are positively correlated to regional economic growth, so this result was expected

The Office for National Statistics (ONS) publishes GDP for ten regions The North-West region is used as a proxy for GDP in the Manweb and Norweb distribution areas. Likewise the South-East region is assumed to cover the Seeboard and Southern distribution areas. Although there is not a close correlation between the standard ONS regions and the REC regions, there will be a close correlation between business activity within a region and the neighbouring areas The output cycle for each region is defined as·

$$\text{output cycle} = \frac{Y^{*}_{RT}}{Y_{RT}} \tag{6.7.1}$$

where Y^{*}_{RT} is the fitted time trend of real GDP for region $[R]$. This will measure above and below trend GDP at factor cost. When a region has above trend GDP, the panel regression indicates that the TFP index will be higher compared to below trend GDP according to table 6.7.3 below. Maximum demand is also positively correlated with TFP

Variable	Coefficient	t-Statistic
OPEX	-0 003	-40 1
Output Cycle	-0 33	-5.1
Maximum Demand	0 00002	2 4
REG	0.018	5.7
SECUR	-0.0001	-2 0

Table 6.7.3 Generalised least squares fixed-effects panel regression

What is noticeable about all three panel regressions is that from a policy perspective, the best way for an under-performing distribution company to raise their level of productivity growth is to cut operational expenditure. A one-percent reduction in real OPEX will increase productivity by 0.69%. A second option available to managers is to redirect resources towards reducing the number of supply interruptions experienced by customers. Where supply quality is included as an output, improvements in supply quality are one of the most immediate ways of raising overall productivity growth. From the analysis a one-percent reduction in this variable will increase productivity by between 0 029% and 0.053%

REC	1992	1993	1994	1995	1996	1997	1998
EAS	-4.3	-2.5	-11.7	1.7	-14.7	-11.9	-3.0
EME	-7.1	-6.4	0.0	0 0	-11 6	-7.8	0 8
LON	-7 6	-9.3	-3.0	-3.1	-9 0	-12 0	-6 4
MAN	-6 9	-1 9	6 6	-13.3	5.1	-17.5	1 2
MEB	-2 8	-8 6	-8 8	4 1	-13.9	0.0	-3 1
NOR	1.8	-3.5	10 9	3 3	-6.3	-9.3	-6 5
NWB	8.7	-12.1	4 6	3 8	-16 9	-5.1	-8.4
SEE	0 0	-1 4	-2 7	0 7	-14 7	-29.5	0 0
SOU	-2 5	-8 2	1 7	-17 6	-12.7	-13 7	-4 4
SWA	-2 0	-7.3	1.1	0 0	-23 3	-8 7	0.0
SWB	0 0	4 3	11 7	-1 5	-19.7	-27.4	-9 1
YOR	0 0	0 0	3 7	-17 4	-15.2	-4.3	-7.1

Table 6.7.4 % change in real OPEX

Managers of Southern electricity executed the largest reduction in real operating expenditure (OPEX) between 1990/91 and 1997/98 of 46% from table 6 7 4, although most of the curtailment was achieved between 1994/95 and 1996/97. Table 6 7 5 below shows that annual productivity growth during this period was between 18% and 22%, which were the highest levels recorded by Southern over the entire sample set. Therefore the regression analysis implies that Southern is a leading performer because the incentives provided under price cap regulation encouraged management to increase profit by cutting employee, since operational expenditure acts as a proxy for this Low productivity during the early years may be accounted for by restructuring the business so future cuts were operationally feasible

Changes in real OPEX also help to explain why South Western followed a different TFP index path to East Midlands, London, and Yorkshire in the middle ranking cluster of RECs. They increased real OPEX by 4.3% in 1992/93 and 11.7% in the following year. Consequently productivity regressed by 20% between 1990/91 and 1994/95 However large cuts in real OPEX were made in 1995/96 and 1996/97, which resulted in South Western increasing productivity by 24% and 40 3% in those two years Further cuts made in 1997/98 helped further improve productivity by over 8%. In contrast Northern's poor performance is partly explained by their modest decrease in real OPEX of 11% between 1990/91 and 1997/98.

REC	1992	1993	1994	1995	1996	1997	1998
EAS	6.6	2.5	14 4	-0 5	18 8	15.8	3.7
EME	5.7	6 8	1 2	0 7	17.8	10.1	0 5
LON	4.9	6 8	5 0	2.4	16.4	18 5	4 9
MAN	6 7	2.7	-3 7	17.5	-4.3	20 7	-0 5
MEB	0 6	8 4	12 4	-3.1	20.9	1.1	4 3
NOR	-3 6	3 4	-8.7	-3.4	8 8	11 3	8 4
NWB	-7.1	13.8	-2 8	-2.5	23.6	6.9	8 9
SEE	-4 6	0 4	2.5	-0 6	16 5	47 8	2.1
SOU	-1.4	4 6	0 6	22 0	17.7	21.0	3 8
SWA	-10.6	7.9	2.2	1 3	34 1	9 6	3.7
SWB	-11.7	-5.7	-5 5	-0 5	24 2	40 3	8.3
YOR	-1.5	0 2	-2 3	21 9	20 3	5.6	11.3

Table 6.7.5 Annual productivity improvements in model two

If tables 6.7.4 and 6.7 5 are compared, there is a strong correlation between reductions in operational expenditure and improvements in productivity Very few observations differ from this hypothesis, and since reductions in real OPEX appears to be the main driver of productivity from the panel regressions, these results support this conclusion.

Table 6.7 6 below diagnoses that the distribution industry has followed a downward path in the number of supply interruptions per one hundred customers. London electricity whilst having a consistently good quality record over the sample period has not made further inroads into improving quality. A similar pattern emerges for Eastern, Seeboard, and Southern, although they offer an inferior quality of service Yorkshire electricity on the other hand has made great strides in improving quality of service for their customers. In 1991/92, the number of interruptions fell by over 50%, which would increase the TFP index between 2 6% and 4.8%.

REC	1992	1993	1994	1995	1996	1997	1998
Eastern	-10 5	41.2	-38 5	10 2	30 8	4.7	-16.9
East Midlands	-51 5	-8 5	22.7	4.3	1 0	-2 1	-2.1
London	14.6	-19.1	-5 3	11 1	-17.5	18 2	0 0
Manweb	-9.8	16.2	3.5	-21.3	-11.4	-8 1	0 0
Midlands	-35 3	17.3	-3 1	-3.2	14 9	6 5	-10.8
Northern	-16 7	-3 3	-8 0	11.3	1.1	-1 1	1.1
Norweb	6.9	-8.1	-1.8	25 0	-12.9	-1 6	40.0
Seeboard	-8 2	54 4	-37.4	4.6	-8 8	-3 6	13.8
Southern	1 3	1.2	-4.9	-3.8	5.3	0 0	-7.6
SWALEC	-19 4	-14 5	9 7	2.8	1 4	-13 9	-3.1
SWEB	-11.6	-8 5	0 8	4 2	-6.5	-8 6	0 0
Yorkshire	-56 3	4 3	-1 4	19.7	1.2	8 1	-14.0

Table 6.7.6 % change in interruptions per 100 customers

The panel regression also helps to explain why London electricity achieves higher productivity in model two. In table 6 7 7 London were able to achieve one of the smallest increases in the value of capital stock from 1990/91 to 1994/95, and then sustained reductions in this variable between 1995/96 and 1997/98.

REC	1992	1993	1994	1995	1996	1997	1998
Eastern	17 6	7.2	1 6	4.3	0 0	-0.9	5.3
East Midlands	21 4	6 8	2 2	3.5	-9.3	-0 3	2.5
London	20.1	4.8	1 7	3 3	-3.3	-4.0	-1.9
Manweb	20 0	5.5	2 2	3 5	-2.0	-2.6	1.7
Midlands	20 3	7.6	2 8	3 4	-2.1	1.5	2.7
Northern	22.0	4.0	-0.9	3.1	-3 2	-1 0	5.3
Norweb	25.2	5.4	1 6	4 0	3 2	2 0	7 1
Seeboard	30 0	6 1	3 0	0 8	-1.1	1.7	5 9
Southern	23.1	5 3	2 6	5 1	0.7	-0.6	4 5
SWALEC	47.5	20.5	1 5	-1.7	-2 8	-0 2	1.3
SWEB	20 6	3 4	2 4	4 9	-2.0	-0 6	2 2
Yorkshire	20.7	5 1	1 9	3 9	-1 2	-1 4	1 4

Table 6.7.7 % change in real Capital Stock

SWALEC's performance in 1991/92 is adversely affected by a large increase in capital stock of 47.5%, which reduces productivity by between 2.6% and 3.1% assuming other factors remain constant. However by 1995/96 the rate of increase in productivity is 34%, coinciding with a strategy of reducing real capital stock. As the next review approaches in 2000, the distribution companies are starting to increase capital stock again This may be related to meeting their overall and guaranteed standards of performance. Companies who are able to supply this guaranteed level of quality at a lower capital stock than anticipated in the regulatory control will benefit from a higher productivity growth rate, which is substantiated by the panel regressions

6.8 Price controls

The annual average price control between 1990-2000 is $RPI-3$. This means that for an average distribution company to be left with the residual claimant, it would have to produce an annual TFP growth rate in excess of 3% Table 6.8.1 below illustrates annual price changes since privatisation for all twelve distribution businesses Suppose that by the end of the ten-year period, the regulator observes annual productivity growth of $[Y]$ per annum. The second distribution price control (1995) and NGC's price control in 1996 indicate that the regulator will demand a one-off reduction in price that is related to the difference between $[Y]$ and the regulated $[X]$ factor.

Productivity growth has varied over the post-privatisation period Therefore the regulator will have to balance the effects of slow growth in the early years with faster growth towards the end, when making predictions for future total factor productivity growth The regulator will also have to decide whether to keep the variation in price controls between the RECs as at present, or narrow this range. At present London with an annual average price reduction of 3.5% has the toughest price control, while SWEB has the most relaxed regime of 2 4% per annum

Chapter two discussed the options available to a regulator for passing the efficiency gains achieved by companies, and for removing the cost inefficiency of an average company towards the frontier line. A smooth glidepath could be adopted over the price control, or a large proportion of the inefficiency could be removed over the first couple of years of the new control

	Real % price change 1990/1 –1994/5	Real % price change 1995/6	Real % price change 1996/7	X factor	average % real price change
EAS	0.25	-11	-10	-3	-3 0
EME	1.25	-11	-13	-3	-2.8
LON	0 00	-14	-11	-3	-3 5
MAN	2 50	-17	-11	-3	-2.7
MEB	1 15	-14	-11	-3	-3.0
NOR	1 55	-17	-13	-3	-3.3
NWB	1 40	-14	-11	-3	-2 9
SEE	0.75	-14	-13	-3	-3 4
SOU	0 65	-11	-10	-3	-2 8
SWA	2 50	-17	-11	-3	-2 7
SWB	2 25	-14	-11	-3	-2.4
YOR	1.30	-14	-13	-3	-3.1
Avg	1.00	-14	-11.5	-3	-3.0

Table 6.8.1 Distribution price control (Offer 1995a)

TFP growth per annum for the industry based on an average of all the models is 6 5% Contrast this figure with an average X factor of 3%, and a measure of out performance can be made based on equation 6.8.1.

$$P_0 = \left([1-(0.065-0.03)]^{10} - 1\right) \times 100 = -29\ 97\% \qquad (6\ 8\ 1)$$

If this is the average measure of out-performance, it is important that those companies who have exceeded the average do not have the extra cost savings confiscated by the regulator Inefficient firms will not have achieved cost savings to pass on to customers, but it must reduce prices by P_0 in the first year of the new control followed by X Frontier firms should be required to reduce prices each year of the control by the average annual rate of cost reduction needed to reduce the average level of inefficiency to zero by the end of the new price control Frontier firms should also avoid having to make P_0 adjustments that are larger than the least efficient firms

Table 6.8.2 takes an average TFP for all the models and calculates a measure of out performance over the last ten years.

REC	Average TFP (%)	Average price reduction (%)	Outperformance (%)
Eastern	8.5	3.0	-43
East Midlands	6.3	2.8	-30
London	6.9	3.5	-29
Manweb	5.5	2.7	-25
Midlands	5.7	3.0	-24
Northern	2.7	3.3	6
Norweb	5.0	2.9	-19
Seeboard	8.1	3.4	-38
Southern	9.5	2.8	-50
SWALEC	5.9	2.7	-28
SWEB	6.1	2.4	-31
Yorkshire	7.6	3.1	-37

Table 6.8.2 Measure of out performance

Ofgem (1999a) in its draft conclusions required the two frontier firms to make larger price cuts in 2000/01 (34% and 28%) compared to the least two efficient firms (28% and 24%). This would have sent the wrong signals to companies if Ofgem had maintained these proposals, because highly productive companies who applied innovative cost reducing ideas were penalised.

Ofgem have maintained annual price reductions for each REC of 3% for all companies between 2001/02 and 2004/05. I believe however that this is a missed chance given that the analysis produced in this chapter has indicated that there has not been a movement of inefficient RECs moving closer towards the frontier. Yardstick regulation would have given a tighter price control for the inefficient firms than is currently planned for 2000/01 to 2004/05.

6.9 Conclusions

Several measures of productivity growth have been carried out. For example O'Mahony (1999) estimates that labour productivity in UK electricity supply rose at an annual rate of 7% from 1990-96, while in comparison labour productivity in manufacturing rose by 3 5% per year in the same period The standard analysis of productivity growth in economics starts from the growth accounting approach used by O'Mahony Several earlier studies (e g Burns and Weyman-Jones (1994, 1996b, 1998b) have used DEA or stochastic frontier model analysis to evaluate this efficiency change in the regulated electricity distribution industry, with conflicting results. In the immediate aftermath of privatisation productivity growth seemed not to differ markedly from pre-privatisation experience, but considerable improvement has been achieved in later years One of the drawbacks of the results analysed in this chapter is that the productivity improvements are largely due to the frontier shift (the best firms getting better) and is offset by a worsening catch-up effect (the worst firms getting relatively worse). In other words the dispersion of efficiency remains just as large towards the end of the 1994/95 – 1999/00 price control as at the beginning of the control

This is a disappointing result particularly since the strong incentive principles in yardstick price cap regulation were designed to bring about a convergence in performance. A possible explanation for this result is that the price cap of $RPI - 3$ retrospective from 1990-2000 is not a binding constraint. Therefore companies were able to provide satisfactory rewards to shareholders in the principal-agent game involving shareholders and managers, while not having to exert effort to produce strong technical efficiency improvements.

Broad conclusions that can be made about the results are that there are three major clusters of performance. Eastern, Seeboard, and Southern have regularly represented the leading performing companies between 1990/91 and 1997/98, with annual productivity growth in excess of 8%. Midland, Manweb, Norweb, and Northern have consistently under-performed the industry average of about 6.5% for all the models tested

Measuring the total factor productivity index since privatisation only explains half of the picture Of more relevance to this study are the causes of productivity growth which includes measurement for the effects of the regional business cycle that can make organisations look more efficient in an economic expansion if inputs are slow to adjust. Effective management will seek to control real operating expenditure, and will be rewarded with a higher residual claimant The level of capital stock is negatively correlated to productivity growth, so regions that have spent more on transformer capacity and strengthening the low voltage network will experience an inferior outcome, compared to those regions that have a high level of industrial customers who use the high voltage network The final variable that managers can directly influence is the number of customer interruptions occurring each year. Managers who switch resources towards improving this quality of supply indicator will contribute positively to productivity growth. This might explain why Midland's performance is constrained by the high number of supply interruptions experienced by its customers.

The panel regression also shows that Gross Domestic Product (GDP) and electricity distributed in each region are positively correlated with total factor productivity. Regions who have above trend GDP experience higher productivity compared to below trend GDP. When cyclical effects are corrected for, productivity due to technological progress and structural shifts will be smaller in above-trend GDP regions The principles of yardstick competition should remain in any future regulatory decision because they provide the necessary incentives for companies to behave in a quasi-competitive market However the evidence also suggests that the new price control needs to be binding so managers exert strong technical efficiency effort in the principal-agent game

More generally this chapter has identified three important conclusions. Productivity growth is still relatively dispersed which suggests more scope for yardstick regulation The business cycle impacts on measured productivity growth, which makes forward looking regulation problematic. Finally the calculation of relevant incentive-based X factors will remain a difficult problem for the foreseeable future in the regulated network distribution industries

Chapter 7 Retail Supply Competition

7.1 Introduction

When the electricity industry was being privatised in 1990, the supply market was to be opened up to competition in several stages. In 1990, those customers that incurred a maximum demand in excess of 1MW would have their market liberalised to encourage new entrants into the market, who were predominantly the major generating companies Since 1994, customers with a maximum demand in excess of 100kW have been able to benefit from competition from suppliers apart from the regional electricity company (first tier supplier). Over 20% of customers who have a maximum demand between 100kW and 300kW have chosen 2nd - tier suppliers (new entrants), securing significantly lower prices, and a greater choice of contract terms including billing and payment methods.

There are a number of themes that this chapter explores, which are important in the liberalisation of the retail supply market New entrants require access to the local distribution network before it can act as a supplier to the customer An efficient component pricing rule is shown to demonstrate the necessary properties for efficient competition, and it also supports historical subsidies that have been used as part of a "universal service" guarantee.

The next two sections focus on the contestability of the market, and the bargaining power of retailers using a model by Dobson and Waterson (1997). This section is designed to highlight some of the potential dangers of a more concentrated retail sector that is likely to evolve over time, and refutes the ideas of countervailing power

A number of non-price competition issues are summarised, covering vertical integration, product quality, and the design of contracts. The final section examines issues related to load profiling because this has been adopted to estimate a customer's profile because of the high cost of installing half-hour metering technology.

7.2 Scope for Competition

In the 100kW market, the Supply business margin is 2% of the total customer's bill. Contrast this with the cost of purchasing electricity from generators which is around 60% of the bill. Hence an efficient purchasing strategy from generators would be required to enter the retail market since this is one area where efficient strategies would reduce costs to the end user.

A change in supplier is dependent upon a number of factors including the relative price and terms of supply, metering and settlement costs; information and confidence that customers have in the new arrangements. Initially the incumbent supplier will have a degree of market power. Competition in the under 100kW market will be less active for the smaller commercial and domestic customers The regulator therefore put forward proposals, which focus protection on smaller customers during the transition to competition The proposals are based on maximum price restraints, to "reassure customers and increase incentives to efficiency" (Offer 1997a, p.3).

Regulation can never replace the benefits of competition Therefore the regulator has correctly allowed scope for new entrants to operate more efficiently and provide new products while at the same time reduce prices for customers who may not benefit initially from competition Therefore the price restraints, which have been agreed, will last for two years initially, and cover the domestic and small non-domestic customer (consume less than 12,000kWh)

The regulator has assumed that with the ending of the *coal contracts*, a REC franchise market purchase cost will fall by 4.5% in real terms in 1998/99 Furthermore the regulator argues that Independent Power Producing contracts should be spread over the whole market, and not just to the small customers. This implies that purchase costs in 1998/99 will fall by a further 3.5% in real terms Therefore purchase costs are expected to fall by at least 8% in real terms However this has been weighted by 1996/97 yardstick differentials among the Recs, so that companies with higher purchase costs will need to make greater reductions, while still leaving scope for new entrants to enter the market For if those very efficient Recs had to reduce purchasing costs by the same rate as inefficient Recs, it would be harder to penetrate the former

Recs market. Taken together, the regulator has set tariffs implying an average real reduction of 9% compared to tariffs in August 1997, with 6% taking place in April 1998 and a further 3% in April 1999.

7.3 Access Pricing

One of the problems that have to be resolved to provide for effective competition, is the question of access to the distribution network. Suppose a high access distribution charge is set for non-domestic customers, providing additional revenue for the PES in the domestic supply business Cross-subsidisation provides a mechanism for the PES to compete effectively with new entrants, even if it is less efficient This policy will distort competition, and lead to inefficient suppliers serving a large proportion of customers Welfare will be reduced, and so facilitating competition in the electricity industry requires non-discriminatory open access to the transmission and distribution network, for all generators and suppliers

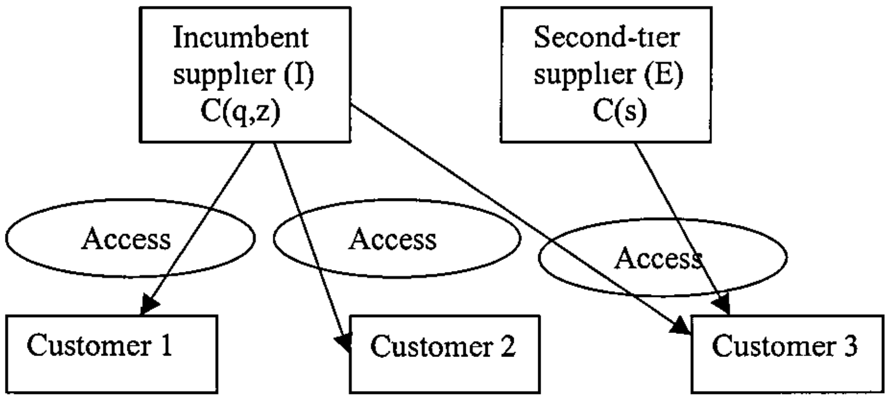

Figure 7.3.1 Access to the local distribution network post 1998

Armstrong, Doyle and Vickers (1996) discuss the question of network access pricing. A general model was presented to demonstrate the potential problems of access in the telecommunications industry in New Zealand. The findings in the paper can be applied to the electricity industry, particularly in the light of full retail supply competition.

Figure 7.3.1 illustrates the following model. The incumbent supplier (first party) has two products to market and they are electricity supply to the customer (q), and access to its distribution network (z). What level of access charge should the incumbent make to the new entrant (third party) that covers the cost of providing the access, and provides a reasonable remuneration to the incumbent for the opportunity cost foregone in providing access to a second-tier supplier? Ramsey pricing as a framework is adopted to examine the issue, and is presented as follows.

Consider a vertically integrated company that provides access to the upstream distribution business to supply electricity to retail customers. Let $[mce_1]$ define the marginal cost of the final output (energy), and $[mca]$ denote the marginal cost of access to the incumbent's upstream distribution network Supply of access made available by the incumbent is z, and the new entrant's demand for access is s In equilibrium, the incumbent's output, $q = X - s = X - z$ where X defines the demand for electricity supply. The entrant pays an access charge (P_a) for the right to sell electricity supply at price (P_1), the price of the incumbent. In this model, the new entrant is assumed to be a price taker, while the incumbent is already established in the market. The entrant's profit maximisation level is given by

$$\pi(P_1 - P_a)s - c_2(s) \qquad (7\ 3\ 1)$$

where $c_2(s)$ denotes the entrant's energy costs. The objective for the regulator is to maximise welfare subject to the constraint that the distribution company supplying access is financially viable Given that consumer surplus is given by $v(P_1)$ and the incumbent's producer surplus is

$$\Pi = P_1(X(P_1) - z) - (P_1 - P_a)s - C(q,s) \qquad (7\ 3\ 2)$$

The second best welfare function to be optimised is:

$$L = v + \pi + (1 + \lambda)\Pi \qquad (7.3\ 3)$$

The shadow price of the incumbent's financial viability constraint is λ. Differentiating with respect to price P_1, and re-arranging

$$\frac{P_1 - mce_1}{P} = \left(\frac{\lambda}{1+\lambda}\right)\frac{1}{\eta_x} \qquad (7\ 3\ 4)$$

where η_x is the price elasticity of demand for good X, and $\frac{\lambda}{1+\lambda}$ demonstrates the mark-up of price over the marginal cost of energy for the incumbent The more protection required for the incumbent to provide for adequate profits, the greater is the mark-up of price over marginal cost. Similarly differentiating with respect to m, where $m = P_1 - P_a$, and rearranging yields

$$\frac{P_1 - P_a - (mce_1 - mca)}{P_1 - P_a} = -\left(\frac{\lambda}{1+\lambda}\right)\frac{1}{\eta_S} \qquad (7\ 3\ 5)$$

where η_s is the new entrant's elasticity of supply. The margin (m) says that the difference between the retail and access price should equal the incremental cost of supply. If the incumbent is able to set a price (P_1) without incurring a loss, this is evidence of a first-best access pricing policy. Therefore the break-even constraint does not bind, so $\lambda = 0$. However if the firm makes a loss when pricing at marginal cost due to increasing returns, the incumbent's break-even constraint binds at the social optimum. Hence $\lambda > 0$, and the Lerner index for each product, $\frac{P_1 - mce_1}{P_1} > 0$

When there are no fixed cost recovery problems, marginal cost pricing is the optimal pricing policy such that the price for final downstream supply is represented by

$$P_1 = mce_1 + P_a = mce_1 + mca \qquad (7\ 3.6)$$

However this is not the case for a network distribution business, so to ensure financial viability as a stand-alone business, the efficient component pricing rule (ECPR) also includes a component equivalent to the opportunity cost of supplying access to a competitor. The opportunity cost is the difference between the retail price and the marginal energy and access cost of displacing a unit of its own supply with a competitor's supply, so the price of access is re-written as.

$$P_a = mca + \left(P_1 - \left(mce_1 + mca\right)\right) \qquad (7.3.7)$$

A simplified illustration of these ideas is illustrated in figure 7.3.2 below In the right hand panel of figure 7.3.2 the incumbent monopolist's profit maximising decision is shown. Marginal cost is the sum of marginal cost of network access or use (mca) and marginal cost of energy purchased (mce_1). The profit maximising price is P_1 and π is the profit per unit of electricity supplied: $\pi = P_1 - (mca + mce_1)$ ECPR ensures that by permitting an access price $P_a = (P_1 - mce_1)$, an entrant is only viable if its marginal cost of energy, mce_2, is competitive with the incumbent's. $mce_2 \leq mce_1$ This is true for mce_2^*, but not for mce_2' in figure 7.3.2. The price of access P_a then equates to $(mce_2 + \pi)$, i.e. includes the lost profit to the incumbent on the third party sales. The Bertrand equilibrium analogy of the analysis is suggested by the fact that at $mce_2 < mce_1$ the entrant efficiently captures all of the supply and the incumbent provides only the access

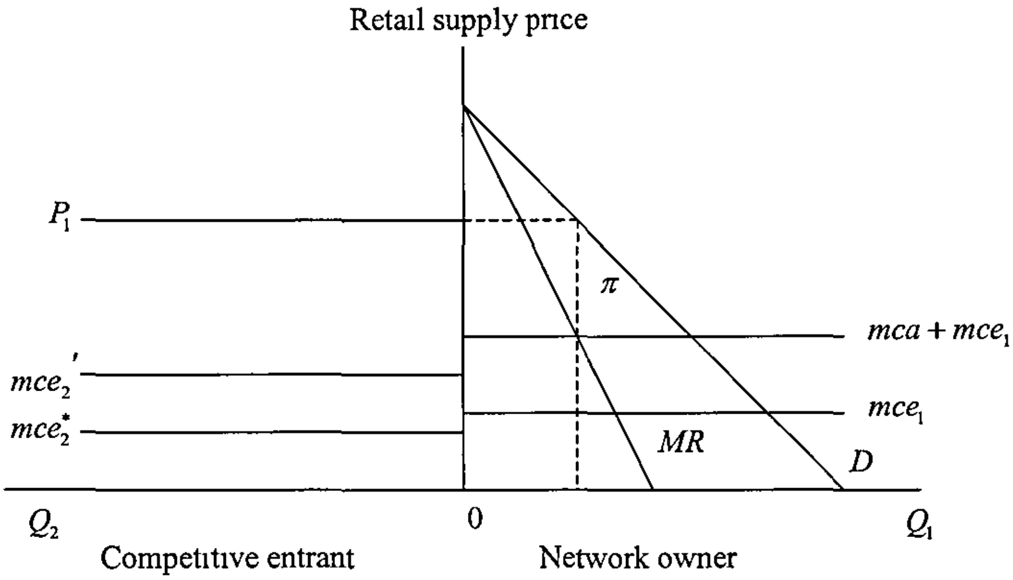

Figure 7.3.2 Unbundling products for access pricing

Product differentiation can exist in the supply market, as in any other competitive market. Vickers (1997) extends equation 7 3.7 to write.

$$P_a = mca + \sigma\left(P_1 - \left(mce_1 + mca\right)\right) \tag{7 3 8}$$

where σ is the *displacement ratio,* defined as the ratio of (a change in output sales for the incumbent with respect to the access price) to (a change in supply of access to new entrants with respect to the access price)

One can now turn to the multi-product case. Assume there are (N) final products supplied by the incumbent, and (R) final products by the new entrants (fringe). There are (M) types of access supplied by the incumbent. The idea behind this model is that electricity can be supplied to different types of customers In a competitive supply market, this is increasingly likely to happen. These new assumptions can be incorporated in the model as:

$$P_{am} = mca_m + \sum_{n=1}^{N} \sigma_{mn}\left(P_n - \left(mce_n + mca_n\right)\right) + \sum_{i \neq m} \rho_{mi}\left(P_{ai} - mca_i\right) \tag{7.3 9}$$

Equation 7.3 9 shows the price of supplying access type (m). The second term explains the opportunity cost to the incumbent as a result of supplying the fringe with the marginal unit of access service (m) The final term defines the total loss of profit to the incumbent in other access markets caused by an increased supply of access service (m) that it provides In addition, ρ_{mi} denotes the increase in demand for other access services when access service m is reduced by one unit.

Three assumptions have to be made about the displacement ratio σ to ensure a value of unity in equation 7 3 8· homogeneous products; fixed coefficients technology (one unit of output requires one unit of access), no bypass (incumbent supplies all access via it's distribution network) The first of these assumptions may be relaxed. Consequently when the demand for access by a new entrant increases by one unit, the incumbent will not see a one unit reduction in demand for it's product, because of customer inertia, brand loyalty, and the like, inducing $\sigma < 1$. Product differentiation will lower the access price relative to homogeneous products.

The regulatory issue of the network owner's profitability remains. In figure 7.3 2 the incumbent is an unregulated monopolist. Laffont and Tirole (1996) have suggested a global price cap in which the intermediate good (access) is treated as a final good and included in the computation of the price cap. This treats access and supply symmetrically in a Ramsey pricing framework The general view (as in the UK) is to have separate access and retail prices as part of an asymmetric model.

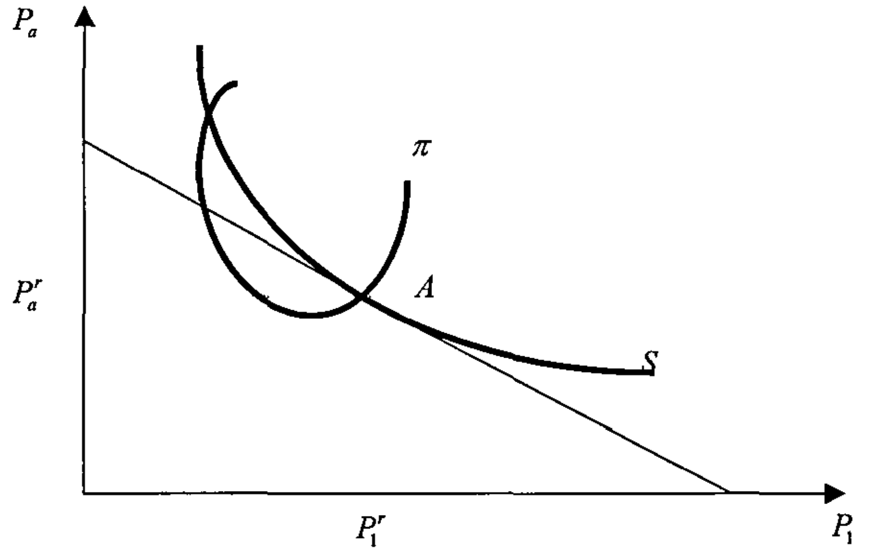

Figure 7.3.3 Global Price Cap

The efficiency gain of using the global price cap suggested by Laffont and Tirole can be neatly illustrated in figure 7.3.3, which is derived from Vickers (1997) The final price and the access price are displayed on the horizontal and vertical axes Separately regulated price caps are shown at point A as P_a^r and P_1^r. This pair of prices will generally lie on an iso-profit contour labelled π, and an indifference curve of consumer surplus labelled S Consumer surplus improvements are represented by S contours closer to the origin, while profit gains to the firm are represented by π contours further from the origin All of the area above the profit contour and below the consumer surplus contour represents price pairs which are more efficient than the pair at A. We can construct a global price cap $wP_a + (1-w)P_1 = \overline{P}$ through point A such that points between the locus and the π contour are more efficient than A without the consumer paying more in aggregate than at A If the weights are proportional to the actual quantities consumed at A, the locus will be tangential to the S contour at A

Any chosen combination in the area between the locus and the profit contour will approximate to a more efficient entry-access allocation than the one implied by the separate price caps, and will yield a Ramsey pricing outcome. The incumbent will concentrate where it has a comparative advantage, reflecting Bertrand entry in ECPR.

The regulator has opted for maximum price limits for 1998-99, and 1999-2000, to protect customers who will initially not benefit from competition For access pricing this has the following effect, reflecting what Laffont and Tirole describe as the general asymmetric approach:

$$P_1 \leq \overline{P_1} \quad \text{and} \quad P_a \leq \overline{P_a} \tag{7.3.10}$$

where the access price cap is determined by the distribution and transmission price controls The RECs and NGC are expected to publish indicative Use of System charges well in advance of implementation, and efficiency requires that these are the same for each entrant to a particular supply market.

Access pricing may need floors and ceilings to prevent inefficient suppliers entering the market or to prohibit barriers to entry Without use of a global price cap, Vickers worries about the distortion arising from partial regulation, a special case of equation 7.3.10. If the access price is regulated $P_1 - P_a$ will widen, increasing productive inefficiency, as less efficient rivals enter the sub 100 KW market To prevent predatory pricing, on the other hand, as a result of some competitive energy costs being allocated to the regulated business, Vickers (1997) suggests a constraint such as:

$$P_1 - P_a \geq mce_1 \tag{7.3.11}$$

De Fraja and Waddams Price (1999) outline a model to demonstrate that welfare can be enhanced by allowing the incumbent to choose from a menu of retail prices that are dependent upon the extent of new entry. This model is particularly useful when a market is opened up for a limited number of customers initially, such as for industrial customers with annual consumption of 100 ML and above in the water industry In this model the regulator does not set the access price, but publishes two sets of prices combining of a unit price (p) and a fixed standing charge (t) for the domestic market. The incumbent chooses how much to produce and the access charge, and then new entrants will decide whether to enter.

An important lesson that can be drawn from the model is that the incumbent can lower its outputs and access price in the industrial market to encourage new entry in exchange for higher profit in the residential market through a higher fixed charge (assuming $p_e = p_n = \text{marginal cost}$). If this happens the incumbent will choose the residential contract (p_e, t_e), else it will choose (p_n, t_n)

The present integration of distribution and supply activities benefits the dominant supplier. Four principle areas stated by Ofgem (1999e) in favour of seperation are.

1. Incumbent will "seek to operate the supply and distribution businesses to maximise the benefits to the company in a way which disadvantages competing suppliers" i e. in setting the structure of the distribution use of system charges
2. Incumbent "may have access to information about the position of competitors and about the intentions of the distribution businesses which are not available to other suppliers", such as through the operation of customer services shared with the distribution business
3. Incumbent "may have an opportunity to provide a cross-subsidy for the supply business by allocating costs to the distribution business which more properly should be met by supply".
4. Perception particularly in the domestic market where customers may feel that switching supplier will "result in a less effective response by the distribution business".

The seperation of the two businesses is likely to lead to a reduction in the number of national suppliers as they merge to reduce costs and pursue a national strategy Furthermore it allows generators to purchase supply companies to reduce their risk in a more competitive operating environment e g National Power and Midland Electricity's supply business

7.4 Contestable Markets

Differences in electricity prices between the incumbent supplier and new entrants are less than £30 for the whole year Customer inertia may be a more likely outcome in the electricity market compared to the gas market because British Gas was contracted for uneconomic supplies of gas initially, enabling new entrants to undercut them as they were able to purchase gas at the market rate. Table 7 4.1 below illustrates a comparison of high price, low price, and average price retail contracts with the incumbent (Eastern electricity) for standard tariff customers

	Annual electricity consumption MW									
Suppliers	**0.5**	**1**	**1.5**	**2**	**2.5**	**3**	**3.5**	**4**	**4.5**	**5**
Eastern	100	100	100	100	100	100	100	100	100	100
Highest price retailer	141	123	114	109	106	103	103	102	102	101
Lowest price retailer	85	93	91	90	90	90	90	90	89	89
Average price retailer	111	104	99	97	96	95	95	95	95	95

Table 7.4.1 Index of standard tariff electricity prices (April 1999)

Average annual domestic consumption for a customer on a standard tariff is close to 3500kW. A customer who lived in the Eastern region could have saved a maximum of 10% off the incumbent's bill, or £27 over the year. This is because the electricity supply component in England and Wales only makes up around 5% of the total bill. A supplier would have to ensure that it purchases efficiently from generators, but because the supply margin is low, the annual savings that can be achieved are modest

According to the guidelines of the US Department of Justice, key tests for effective competition include the strength of switching barriers; availability of substitutes, and market characteristics such as geographic area The *structure-conduct-performance (SCP)* paradigm suggests a highly concentrated market is correlated with monopolistic pricing although causality has been a contentious issue, the firm neglects quality of service, and incentives to improve productive efficiency are immune to the market

Bain (1956) suggested that there were three main barriers to entry, namely economies of scale, product differentiation, and absolute cost advantages of incumbent firms. The economies of scale that would take place in the electricity industry include:

1. Increased bargaining power with generators for negotiating contract terms
2. Benefit from larger advertising expenditure
3. IT network costs for larger suppliers can be spread among many customers

Customers may have strong preferences for established brands, partly due to the risk-averse nature of customers willingness to change. This is partly a result of the uncertainty of change Therefore entrants would have to spend more on advertising and marketing to put the message across to the public of the benefits of choosing their brand against the incumbents. The case of the Virgin group headed by Richard Branson is a typical case in point.

The higher the risk of bankruptcy for a new entrant, the higher the returns expected by investors. Capital markets that hold this view of new entrants will lead the incumbent to have a cost advantage because it will face a lower cost of capital Hence a bias in favour of large new entrants into the electricity market is likely to materialise i e British Gas and Virgin.

Stigler (1968) would argue that if product differentiation depends only on current expenditure on design, advertising, and sales efforts, and not on past expenditure, and large entrants can purchase these activities on the same terms as the incumbent, then product differentiation would not constitute a barrier to entry. This point made by Stigler (1968) appears to fit the characteristics of the electricity supply market However Sutton (1991) identifies the endogenous sunk costs of establishing a brand image as a principal reason for the empirical observation of higher concentration levels in many retail industries than would be predicted by minimum efficient scale data Product differentiation could be measured in terms of the range of services available such as seasonal and interruptible tariffs, and value-added products such as electrical installation services

Contestable market theory implies that in a market with one supplier, the threat of potential entry will safeguard productive efficiency and welfare gains. In that event market concentration is a poor measure of contestability Much of the literature dealing with contestable markets has concentrated on the circumstances under which it is rational for incumbents to expect entrants to engage in rapid and reversible hit and run entry, in a Bertrand equilibrium framework, which is costless If a potential new supplier can undercut the incumbent and earn a sufficient rate of return, then hit and run entry will occur. These type of Bertrand strategies persist until one of the suppliers is unable to undercut the other player without incurring a loss, and will subsequently exit the market without any sunk assets. Hit and run entry must be credible for potential entry to constrain the actions of the incumbent.

The characteristics of sustainable equilibria in perfectly contestable markets are:

1. Each firm must earn zero profit by operating efficiently.
2. Avoid cross-subsidisation
3. $\begin{cases} 2 \text{ suppliers} \rightarrow P > MC \\ > 2 \text{ suppliers} \rightarrow P = MC \end{cases}$

The second point can be expanded further. The revenues from selling a product must at least meet the incremental cost of the product. Otherwise revenue from the other services, which in this case are other supply markets, metering operations, settlement, or the distribution business must exceed their total stand-alone production costs This form of pricing may invite entry into the market for products, where the market does not exhibit natural monopolistic characteristics, and is potentially competitive.

The appropriate indicators for contestability are therefore (Bailey and Baumol 1984):

1. Productivity improvements in delivery systems
2. Innovation and diversity in the price-service option

3 Adjustment of prices to incremental costs and end to cross-subsidy

4 Transitions in market structure and profitability

In the absence of sunk costs, entry deterrence requires the industry to operate in a sustainable configuration at all times This can be demonstrated using a simple model. Let the capital outlay per unit supplied equal β and the per unit salvage costs by selling capital when exiting the market be α. Then as

$$(\beta - \alpha) \rightarrow 0 \tag{7.4 1}$$

the upper bound on monopoly profits tend to zero.

Is the theory behind perfectly contestable markets applicable to the real world? The lack of sunk costs is a very important condition for applicability. These costs are largely absent when suppliers employ non-specific assets, which can easily be re-sold or used for other purposes. Data base systems are a pre-requisite for entry into the supply market. Therefore potential entrants who already have a large data base network will not incur significant sunk costs. Investment in information may be negligible because information about customers may already be known. I am thinking in particular about the supermarkets and banks that will be able to infer considerable information about the characteristics of their customers

The cost of set-up of a new operation will be largely sunk, as will advertising and sales, to highlight product differentiation. Nevertheless these sunk costs will be small, in comparison to the financial capability of the new entrants, who are likely to be energy companies, supermarkets and other large retailers, and financial services Therefore the electricity supply market appears to convey many of the characteristics of a contestable market.

Of course this does not mean that every supply market for electricity will be contestable to the same degree It is known in the industry that pre-payment meter (PPM) customers are subsidised by other customers because the true costs of installing and operating PPMs is not reflected in the final charge The nature of competition will increase the pressure on tariff re-balancing, which would lead to a welfare loss to the most vulnerable customers OFGEM have taken the view that regulation rather than competition should be used to protect these customers The downside of this private social policy is that it will be harder for potential new entrants to penetrate this market. Otero and Waddams Price (1999) show that on average entrants charge more than the incumbent for a PPM tariff and in five of the twelve RECs this is significant at the 5% level They also prove in contrast that in eight out of the twelve RECs entrants charge a lower bill for direct debit customers which is also significant at the 5% level.

In a competitive market, suppliers will not charge any group of customers a price that lies below the avoidable cost of supplying electricity to them, because otherwise it would be in breach of the 1998 Competition Act under Chapter II prohibitions which come into operation on 1st March 2000 A monopolist will want to raise non-allocable costs from customers who are least price sensitive. Cherry picking will prevent Ramsey Pricing because competitors will target low cost customers first (direct-debit), which will lead to the poorest customers least benefiting from competition as shown by Otero and Waddams Price (1999)

7.5 Bargaining power in a competitive electricity supply market

The opening up of the England and Wales electricity supply market to competition is expected to herald a new era for the industry New trading arrangements to be implemented in the year 2000 enshrine the principles of trading outside a central pool. Bilateral trading between suppliers and generators is therefore likely to be the most common way of pricing the cost of electricity to the supplier.

There has been some debate recently about the margins and bargaining power being exerted by retailers, including supermarkets A new dawn for the electricity supply industry necessitates asking questions related to this. How will bilateral contract prices react to many or few symmetric retailers participating in the supply market? If there are a few dominant retailers of electricity as some predict in ten years time, will the customer retain many of the benefits of competition? Or will retailers be able to negotiate from a position of strength with the generators, but keep most of these benefits for themselves, leaving the customer worse off?

Access pricing theory based on the efficient component pricing rule discourages inefficient entry in a liberalised electricity retail market. As was shown in the access pricing section, a new retailer would only enter the market if it could undercut the incumbent, by having a lower marginal energy cost. Since generation costs account for over 50% of the bill, efficient bargaining strategies lie at the heart of new entry. Dobson and Waterson (1997) examined the implications of bargaining power between upstream and downstream companies

Countervailing power as proposed by Galbraith (1952, p 54) argues that a concentrated retail sector will not only offer cost savings in overheads and staff, but more contentiously increases the retailer's bargaining power for extracting discounts from manufacturers as a result of intense competition. The implications for this argument are significant. In order to reduce the cost of supply further, mergers and takeovers of supply businesses are likely as demonstrated by EDF purchasing London Electricity, and SWEB's supply business.

Dobson and Waterson (1997) make a critical evaluation of countervailing power A simplified version of the model is illustrated here. Assume there is contestable entry and there are presently two symmetric retailers (R_1, R_2) who purchase electricity from a monopoly generator (G). As chapter three shows National Power and Powergen, who represented two of the major price-setting generators under the existing pool trading arrangements, have previously behaved in a way which has resembled collusive games in spot and contract for difference (CfD) markets. Powell (1993) examined the issue of cooperating and non-cooperating games within the context of CfD markets, and assumed that the two generators in effect behaved as a quasi-monopolist

The first retailer (R_1) purchases electricity from the generator at an agreed contract price (c_1). After making an adjustment for a profit mark-up, the end-user will pay a retail price (p_1) for a kWh of supply. The cost of paying for access to the high and low voltage networks have not been included in the end-user price, so broad generalities can be made. This is because the model is only concerned with the negotiations between upstream generation and downstream supply businesses.

A basic inverse demand function for retailer R_1 is given by equation 7 5.1.

$$p_1 = 1 - q_1 - \sigma q_2 \; ; \;\; \sigma \in [0,1] \qquad (7\,5\,1)$$

It assumes that retailer R_1 competes against other retailers. However the extent of this form of rivalry is conditional upon the degree of substitutability or intra-brand rivalry, defined as σ. The theory of access pricing referred to brand loyalty as the displacement ratio. This ratio is able to mitigate the degree of rivalry among competing retailers if there is significant loyalty towards a particular retailer It may be deduced from this that the displacement ratio will play a crucial role in determining contract and retail prices in any bargaining environment, in so far as the higher the displacement ratio, the greater the downward cost pressures faced by the two retailers.

Demand for electricity products sold by two retailers can be solved from 7.5.1 as

$$\begin{bmatrix} q_1 \\ q_2 \end{bmatrix} = \frac{1}{(1-\sigma^2)} \begin{bmatrix} 1-\sigma-p_1+\sigma p_2 \\ 1-\sigma-p_2+\sigma p_1 \end{bmatrix} \qquad (7.5\,2)$$

The first order partial derivative of demand in 7.5 2 with respect to the price of the substitute product is $\frac{\partial q_1}{\partial p_2} > 0$. This means that if retailer two reduces price, demand for retailer one's electricity product will decline, though the rate of decline is constrained by the displacement ratio (σ).

Once a retailer (i) has agreed a contract price with the monopoly generator, its aim is to maximise profit:

$$\pi_{R1} = (p_1 - c_1)q_1 \qquad (7\,4.3)$$

where $p_1 - c_1$ reflects the margin made by retailers. Access pricing showed that undercutting an existing supplier's marginal cost of energy was the only feasible strategy for entry. Since investors would require a certain rate of return, the cost of the contract is highly significant. Profits are maximised by differentiating equation 7.5.3 with respect to price:

$$\frac{\partial \pi_{R1}}{\partial p_1} = \frac{1}{1-\sigma^2}\begin{bmatrix} 1-\sigma-(2p_1-c_1)+\sigma p_2 \\ 1-\sigma-(2p_2-c_2)+\sigma p_1 \end{bmatrix} \tag{7.5.4}$$

Once contracts have been signed between the retailers and generator, the profit stream flowing to the generator, assuming unit costs have been normalised to zero, is expressed as.

$$\pi_s(c) = \sum_{i=1}^{2} c_i q_i(c) \tag{7.5 5}$$

Under symmetric bargaining if the quasi-monopolist generator is unable to strike a deal with retailer(R_1), the generator's profit stream is defined as the opportunity cost to the generator of a breakdown in contractual negotiations·

$$\pi_s(c^*) = c_2^* q_2 \tag{7.5.6}$$

Retailer (R_1) will receive a zero payoff if it is unable to negotiate a contract with the monopolist generator The contract price is characterised by bargaining between the generator and two retailers, so that for retailer 1 the contract price is.

$$c_1^* = \arg\max\left(\sum_{i=1}^{2} c_i q_i(c_i) - c_2^* q_2\right)(p_1 - c_1)q_1 \tag{7.5 7}$$

The first-order condition of equation 7 5 7 derives the perfect Nash bargaining equilibrium set of contract prices for the two retailers:

$$\frac{\partial\left[\sum_{i=1}^{2} c_i q_i(c_i)\right]}{\partial c_i}\left[(p_i - c_i)q_i\right] + \left[\left(\sum_{i=1}^{2} c_i q_i(c_i)\right) - c_2^* q_2\right]\frac{\partial\left[(p_i - c_i)q_i\right]}{\partial c_i} = 0 \qquad (7.5.8)$$

Symmetry is assumed between the bargains of the two retailers and the generator to derive an equilibrium contract price c^* from equation 7.5.8. Dobson and Waterson then construct retail prices and margins, for a variety of displacement ratios. Except for when there is intense competition and services are almost perfectly substitutable $(\sigma = 0.99)$, lower prices are attained by having more than two retailers. This refutes the idea of countervailing power, whereby the market has two symmetric independent price setting retailers, and the bargaining position of each prevent concessions being made to the generator thus reduces the contract price down to marginal cost and passing the benefits onto the customer. Table 7.5.1 incorporates a range of displacement ratios and retail suppliers to evaluate the sensitivity of profit margins due to changes in the degree of brand loyalty (σ) and concentration in the market

	Displacement ratio								
Retailers	**0.9**	**0.8**	**0.7**	**0.6**	**0.5**	**0.4**	**0.3**	**0.2**	**0.1**
2	35	61	81	97	111	123	134	144	153
3	17	34	50	67	82	98	114	130	145
4	12	24	37	51	66	82	99	118	138
5	9	18	29	41	55	70	88	108	132
6	7	15	24	34	47	61	79	100	126
7	6	12	21	30	41	54	71	92	121
8	5	11	18	26	36	49	65	86	116
9	4	9	16	23	33	44	60	81	112
10	4	9	14	21	30	40	55	76	108
11	3	8	13	19	27	37	52	72	104
12	3	7	12	18	25	35	48	68	100

Table 7.5.1 Retail Margin (base index 100)

When the existing barriers to switching are addressed the displacement ratio would be expected to rise, and this may lead to a consolidation in the retail supply market as retail margins fall in response to the higher probability of switching Interestingly the model suggests that most of the benefits will remain when there are six major players in the market, as many commentators have predicted will be the case in the long term.

The model is important in the light of the decision by the Secretary of State for Trade and Industry to launch a probe into why 80% of domestic energy customers are not switching supplier despite the savings on offer compared to the incumbent supplier According to Ofgem (2000b), in the first year of domestic electricity competition, four million homes have changed supplier, saving an average of £20 per year. A conclusion that could be drawn is of a displacement ratio that remains fairly low after the first year of competition. New entrants have come into the market such as British Gas. Nevertheless it may be the case that a lack of simple price comparisons and reported sharp practices by salespeople have created a barrier to switching

7.6 Non-price competition issues

Vertical Integration

When the electricity industry was decentralised in 1990, generation, which was assumed potentially competitive, was vertically seperated from the high voltage network (National Grid Company) Regional electricity companies (RECs) had a single licence for distribution and supply. Developments however have pushed the industry closer towards a vertical integrated structure again, albeit in a different form to 1990. Recs were allowed by the regulator to own an equity stake in new CCGT power stations with an objective of stimulating competition in the electricity pool Further attempts by the regulator to stimulate the generation market in 1996 culminated in Powergen and National Power selling 6GW of coal fired price setting plant to Eastern electricity, a distribution and supply business.

The election of a new government in 1997 inherited another coal crisis as a result of the ending of coal-backed contracts in 1998 Ministers saw the lack of competition in generation as an important factor in creating a bias in favour of gas fired power stations Powergen were therefore allowed to purchase East Midlands supply and distribution business in 1998, in exchange for disposing of further generating plant. A reason for Powergen to follow this policy was that generation and supply businesses act as a natural hedge against volume uncertainties in a liberalised supply market and a short-term balancing market. National Power for the same reason was purchased Midlands Electricity supply business in exchange for further divestment of plant.

The electricity industry is characterised by long-lived assets whose costs are effectively sunk because there are no other marketable use for them. Long-term contracts have typically been used to prevent the hold-up problem of opportunistic behaviour. Investments in generating plant are characterised by considerable uncertainty about construction, operating costs, and reliability. Contracts have been used to allow generators to amortise investments without a high degree of risk, while at the same time providing certainty for suppliers purchasing costs (Williamson 1986). However these contracts are incomplete because of bounded rationality.

In a competitive trading environment (retail supply), long-term contracts are no longer applicable to finance investments One option, which has been chosen by the major players so far, is to internalise the risk discussed above through vertical integrating the supply and generation businesses. This raises concerns about the double marginalisation problem Provided either downstream or upstream markets are truly competitive this problem will not arise.

However a more appropriate solution would be to establish a liquid market for forward and futures contracts, which would provide appropriate price signals, and allow entrants to forward sell and purchase output when investment decisions are taken without the need for long-term contracts. This will also increase the likelihood of brokers entering the market and tailoring energy packages to meet the needs of customers

Product quality

Another non-price competition issue that arises is the quality of the supply package offered to customers, who will take this into account when deciding whether to continue with an existing supplier or to switch. A new entrant will be able to make a profit if it is able to provide a higher level of consumer surplus (U) for the customer as defined by equation 7.6.1.

$$U^{incumbent} < U^{entrant} < U^{\max} \qquad (7.6\ 1)$$

If a regulator imposes large price reductions prior to liberalising the retail market, the trading environment will be harder for a new entrant because customers will benefit from a higher consumer surplus. Nevertheless opportunities will remain for a new supplier to enter the market if it is able to credibly commit to producing a high quality of service.

Farell (1986) uses a two period model $(t = 1,2)$ to ascertain whether moral hazard is an entry barrier. In the first period entry is assumed possible and the entrant is able to choose between a high (H) and low (L) quality of service. Asymmetric information is a problem in period 1 because in contrast to the incumbent, the entrant's quality is unknown. At the end of the first period (after one year) the customer will have knowledge about the entrant's quality from either a personal level or via the media.

A conclusion that is drawn from the model is that the new entrant will only choose a high quality of service if.

$$\begin{bmatrix}\text{Discounted profits}\\ \text{in period 2}\end{bmatrix} \geq \begin{bmatrix}\text{Cost difference between a}\\ \text{high and low quality service}\end{bmatrix} \tag{7.6.2}$$

$$\begin{bmatrix}\text{marginal cost of the}\\ \text{high quality of service}\end{bmatrix} < \begin{bmatrix}\text{marginal cost of}\\ \text{the incumbent}\end{bmatrix} \tag{7.6.3}$$

If the incumbent supplier reacts to the competition by reducing price sufficiently so the new entrant is unable to collect the benefits of supplying a high quality product while incurring the associated costs, dishonest entry is a possibility if entry takes place Farell defines this as moral hazard in hit and run entry

Contract design

Liberalising the electricity supply market offers opportunities for retailers to tailor products that meet the demands of customers. Retailers who provide these packages are more likely to succeed in the market Chao and Wilson (1987) proved an important theorem that when transaction costs are recognised "few priority classes suffice to realise most of the efficiency gains from priority service" (p.912). Second degree price discrimination is used to offer a limited number of optional tariffs which increases customers utility because only those customers who increase their service from the tariff will choose to opt.

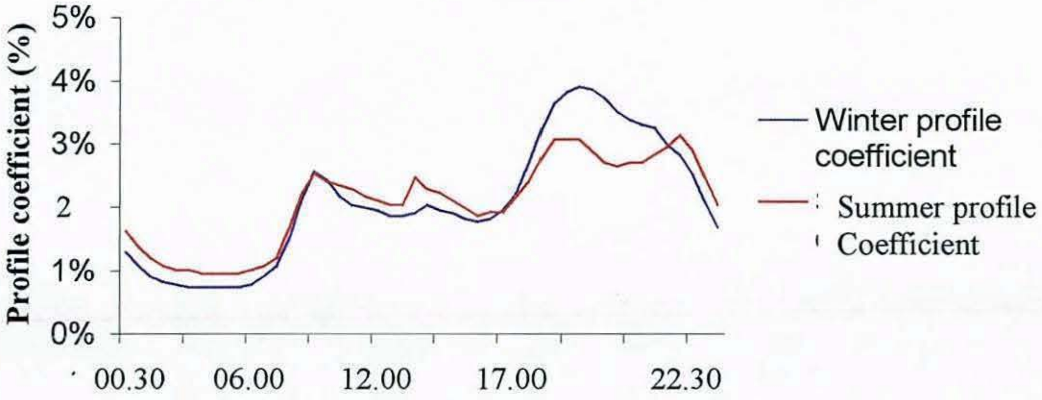

Figure 7.6.1 Domestic Load profile for standard tariff

Figure 7.6.1 illustrates a domestic standard load profile over an average winter and summer day. The design of the contract could be used to offer a discount to customers who do not contribute towards the system peaks. The opportunity cost of peak demand is the cost saving from reducing the demand for higher cost contracts with generators, since the unit cost of electricity is higher in peak periods. This will also affect investment decisions for meeting peak demand, because if the peaks are smoothed there will be savings from requiring the use of a smaller number of high cost peaking plants, and lower transmission constraints will mitigate network reinforcements. A seasonal based tariff is therefore an example of a tariff option that will increase consumer surplus for customers, and provide new markets for suppliers.

Sibley and Srinagesh (1997) describe optional two-part tariffs (E_{ij}, P_{ij}), where E_{ij} is the fixed charge, and P_{ij} is customer i usage charge for the *jth* good. If $Q_{i+1,j}(P) > Q_{ij}(P)$ for all i, j, P, then the demand curves are uniformly ordered. Define V_{ij} as the consumer surplus obtained by customer $[i]$ from market $[j]$. For a two consumer two good model, the bundled approach is to maximise profit subject to the incentive compatibility (ICC) and individual rationality (IR) constraints. The goods in question may be day-time and night-time tariffs for example. The two ICC constraints are defined as:

$$V_1(P_1, E_1) \geq V_1(P_2, E_2) \text{ ; } \quad \lambda_{12} \text{ is the lagrange multiplier} \tag{7 6 4}$$

$$V_2(P_2, E_2) \geq V_2(P_1, E_1) \text{ ; } \quad \lambda_{21} \text{ is the lagrange multiplier} \tag{7 6 5}$$

i e. conditions that ensure that each consumer attains higher utility from the contract designed for him or her rather than one designed for the other consumer.

The two IR constraints are·

$$V_1(P_1, E_1) \geq 0 \text{ ; } \mu_1 \tag{7.6.6}$$

$$V_2(P_2, E_2) \geq 0 ; \mu_2 \tag{7 6.7}$$

i e. both consumers will participate in the market because utility is positive.

Define $P_i \equiv (P_{i1}, P_{i2})$ for $i = 1,2$, and $P_j \equiv (P_{j1}, P_{j2})$ for $j = 1,2$ In this simple model the Lagrangian is constructed as:

$$\begin{aligned} L = \sum_{i=1}^{2}\left(\sum_{j=1}^{2}\left[(P_{ij} - c_j)Q_{ij}(P_{ij})\right]\right) + \lambda_{12}\left[V_1(P_1, E_1) - V_1(P_2, E_2)\right] \\ + \lambda_{21}\left[V_2(P_2, E_2) - V_2(P_1, E_1)\right] + \mu_1 V_1(P_1, E_1) + \mu_2 V_2(P_2, E_2) \end{aligned} \tag{7.6 8}$$

The Kuhn-Tucker conditions are:

$$\frac{\partial L}{\partial P_{1j}} = (P_{1j} - c_j)Q'_{1j}(P_{1j}) + Q_{1j}(P_{1j})[1 - \lambda_{12} - \mu_1] + \lambda_{21} Q_{2j}(P_{1j}) = 0 \tag{7 6 9}$$

$$\frac{\partial L}{\partial P_{2j}} = (P_{2j} - c_j)Q'_{2j}(P_{2j}) + Q_{2j}(P_{2j})[1 - \lambda_{21} - \mu_2] + \lambda_{12} Q_{1j}(P_{2j}) = 0 \tag{7 6 10}$$

$$\frac{\partial L}{\partial E_1} = 1 - \lambda_{12} + \lambda_{21} - \mu_1 = 0 \tag{7 6.11}$$

$$\frac{\partial L}{\partial E_2} = 1 - \lambda_{21} + \lambda_{12} - \mu_2 = 0 \tag{7.6.12}$$

$$\lambda_{12}\left[V_1(P_1, E_1) - V_1(P_2, E_2)\right] = 0 \tag{7 6 13}$$

$$\lambda_{21}\left[V_2(P_2, E_2) - V_2(P_1, E_1)\right] = 0 \tag{7 6 14}$$

$$\mu_1 V_1(P_1, E_1) = 0 \tag{7.6.15}$$

$$\mu_2 V_2(P_2, E_2) = 0 \tag{7 6.16}$$

Substituting equation 7 6 11 into 7.6.9, the optimal bundled usage charges in market j must satisfy.

$$\left(P_{ij} - c_j\right)Q'_{ij}\left(P_{ij}\right) + \lambda_{ji}\left(Q_{ji}\left(P_{ij}\right) - Q_{ij}\left(P_{ij}\right)\right) = 0 \tag{7.6.17}$$

In each market customers are ordered by their demands Assume that customer two has a higher demand compared to customer one in both markets. Customer two will receive the highest consumer surplus possible because the price it pays for both goods is equivalent to marginal cost. To comply with uniform ordering and hence satisfy equation 7 6 11

$$\lambda_{12} = 0, \mu_1 > 0, \lambda_{21} > 0, \mu_2 = 0 \tag{7 6 18}$$

where μ_1 is the participation basis for customer 1 and λ_{21} is the incentive compatibility basis for customer 2. Sibley and Srinagesh (1997) show that when uniform ordering of demand curves is weakly violated $\left[Q_{12}(P) > Q_{22}(P)\right]$, bundling the two products together is "strictly superior" to unbundling in a two good two consumer market. When the goods are unbundled, customer two will pay the marginal cost for product one but will pay a different price when equation 7 6.17 is solved, for product two. Customer one will pay the marginal cost in product two When the two products are bundled together, customer two will always pay the marginal cost in both markets Customer one will be charged a price, which lies above marginal cost for product two and below marginal cost for product one Distortion of the market is necessary to prevent customer two from selecting customer 1's tariff. Customer one will be charged a higher entry fee (E_{11}) to ensure that it chooses $[E_{11}, P_{11}, P_{12}]$ contract while customer two adopts $[E_{22}, c_1, c_2]$

Economy 7 customers who consume more electricity at night than standard customers, face a higher daily standing charge and day-time unit charge, but a significantly smaller unit charge for night-time This partly reflects the lower cost baseload characteristics of generation during the night. For example London Electricity offer a standard and economy 7 tariff.

Rate	Day-time (p/kWh)	Night-time (p/kWh)	Daily standing charge (p/day)
Standard	6 28	6.28	9.77
Economy 7	6.85	2 81	10 68

Table 7.6.1 London Electricity tariff options (1999)

The basic framework outlined will be used by retailers to attract customer type (i) without attracting other customer types for a contract designed with type (i) in mind, for (M) type of services.

7.7 Load Profiling

In the proposed trading arrangements for 1998, customers who exhibit maximum demand below 100KW will have a choice of installing half-hourly metering, or continuing with conventional meters and adopting load profiling for estimating electricity usage Installation costs of a half-hourly meter for 1996-97 are around £500-£800.

Domestic customers are included in the opening up of the electricity supply industry. The benefits they accrue through lower costs of supply are outweighed by the costs of installation, particularly since supply accounts for only 5-7% of the final bill Furthermore, such a policy would create significant barriers to entry, because new entrants are unlikely to be in a financial position to subsidise a proportion of the installation costs, to entice customers to switch supplier.

Load profiles are a low cost alternative to half-hourly meters. They are defined as the pattern of electricity demand for a customer or group of customers over a period of time. In England and Wales, a load profile is measured at half-hourly intervals for a specific or representative day Generic profiles have been applied to domestic customer because they offer a cost-effective method for estimating the average demand for large populations of customers with similar characteristics. These large populations are represented by profile classes. The criteria laid out by the Load Research Group included the need to minimise the variation within each profile class, and subsequently to maximise the variation between each profile class Such a provision would assist in unambiguously allocating each customer to a particular profile class.

Too few profiles would substantially reduce the robustness of them. On the other hand, the benefits of increased accuracy from having many profiles have to be weighed against the extra cost of achieving this. To improve upon accuracy, profiles are derived from monitoring half-hourly demands of a representative sample, which is updated annually. The profiles will be applied to a REC's boundary (*Grid Supply Point Group*)

For 1998, it has been decided that 8 profile classes would suffice for the first wave of competition The eight profile classes include two domestic profile classes covering the unrestricted market (DUR) and economy 7 (DE7). The remaining six are allocated to non-domestic customers Two profile classes will cover the smaller, quarterly billed non-domestic unrestricted and economy 7 tariffs Additionally, four profile classes are allocated to the larger monthly-billed non-domestic customers, where maximum demand (MD) is recorded.

Maximum demand represents the largest half-hourly demand (KW) throughout a 12 month period From this, four measurements of load factor, LF are derived. A high LF indicates a flat demand profile and conversely a low LF indicates a peaky demand profile

$$LF = \frac{\text{Total Annual Consumption}\,(\text{kWh})}{\text{Maximum Demand}\,(\text{kW}) \times 17520\,(\text{h})} \tag{7.7 1}$$

where the total number of half-hours in the year is 17520. The four MD profile classes are

1 $LF < 20\%$
2 $20\% \leq LF \leq 30\%$
3. $30\% \leq LF \leq 40\%$
4 $LF > 40\%$

Each of the eight profiles will have four seasonal profiles representing winter, spring and autumn, summer, and high summer, and a special profile for bank holidays Data recorded two years before will be used for the current settlement year However the profiles are dynamic. The profile coefficients computed for each half-hour will be adjusted for temperature and weather variations Furthermore adjustments can be made to the general profile as will be discussed later.

A calculation of each supplier's energy purchase costs by profile class is now derived in a simplified format. Each January, the Electricity Association (EA) submits regression coefficients and Group Average Annual Consumptions (GAACs) to the Pool. The Initial Settlement and Reconciliation Agent (IRA) is one of the bodies who receive this information. They input each Grid Supply Point's (GSP) temperature and sunset values into equation 7 7 2 to derive a set of profiles for each GSP Group.

$$\overline{y}_{dt} = \beta_{1t} + \beta_{2t} T_d + \beta_{3t} S_d + \beta_{4t} S_d^t \tag{7.7.2}$$

where $\overline{y}_{dt}$ is the sample average demand (kW) in half-hour (t) on day (d), T_d is the noon effective temperature (NET) based on one reading per REC, and S_d is the sunset value for day (d).

An initial estimate of a supplier's profiled half-hourly consumption is.

$$D_{phs} = \frac{\left(PC_{ph} \times EAC_{ps}\right)}{1-\left(L_{ph}/100\right)} \qquad (7\ 7.3)$$

where $p = 1,\ldots,8$ profile classes, $h = 1,\ \ ,17{,}520$ half-hours, and $s = 1,\ldots,n$ suppliers. The generic profile coefficient for profile class $\left(PC_{ph}\right)$, is multiplied by an estimate of the supplier's estimated annual consumption for that profile class $\left(EAC_{ps}\right)$ This is adjusted to take account of line losses for that profile class $\left(L_{ph}\right)$. The profiled consumption for the GSP Group by profile class is then derived as:

$$C_{ph} = \sum_{s} D_{phs} \qquad (7.7.4)$$

Total profiled consumption added across suppliers and profile classes within each GSP Group, $\widetilde{M}_h = \sum_{p} C_{ph}$, is compared with the total metered "take" at the GSP in question. The total metered "take is:

$$M_h = M - M_{hh} \qquad (7.7\ 5)$$

where M is the total metered "take", and M_{hh} is the half-hourly metered take including associated line losses The difference between total profile consumption and metered "take" is known as the GSP Group Correction Factor $\left(F_h = M_h / \widetilde{M}_h\right)$. This is applied to each supplier's profiled consumption by profile class, so each supplier's deemed consumption is derived as:

$$\widetilde{D}_{phs} = D_{phs} \times F_h \tag{7.7.6}$$

Subsequently each supplier's deemed purchase cost is given by

$$X_{hs} = \sum_p \left(\widetilde{D}_{phs} \times PSP_h\right) \tag{7.7.7}$$

where PSP_h defines the pool selling price in each half-hour. There are risks involved in load profiling An underestimate of consumption for a customer, in a particular half-hour will create an error, which will be averaged out between suppliers in the REC's area. Reconciliation payments are settled 14 months of the consumption date, but only take into account volume differences and not shape differences. Economic inefficiency therefore prevails and is magnified in peak periods, with the customer's supplier effectively being cross-subsidised by others. A supplier calculates its demand-weighted price for a profile class in each year by using equation 7.7.8:

$$DWP_{ps} = \frac{\sum_{h=1}^{17520} X_{phs}}{\sum_{h=1}^{17520} \widetilde{D}_{phs}} \tag{7.7 8}$$

The welfare economics of load profiles suggests that they can be treated as if we were designing optimal predetermined tariffs, Wenders (1976) In figure 7 7 1, we draw the utility's load duration curve, $h(q)$, which shows the duration in hours of a given level of kW load. The load duration curve indicates use of two capacity types, baseload (q^b), and peaking (q^p), and these have annual capacity and running costs of c^j and r^j for plant type j

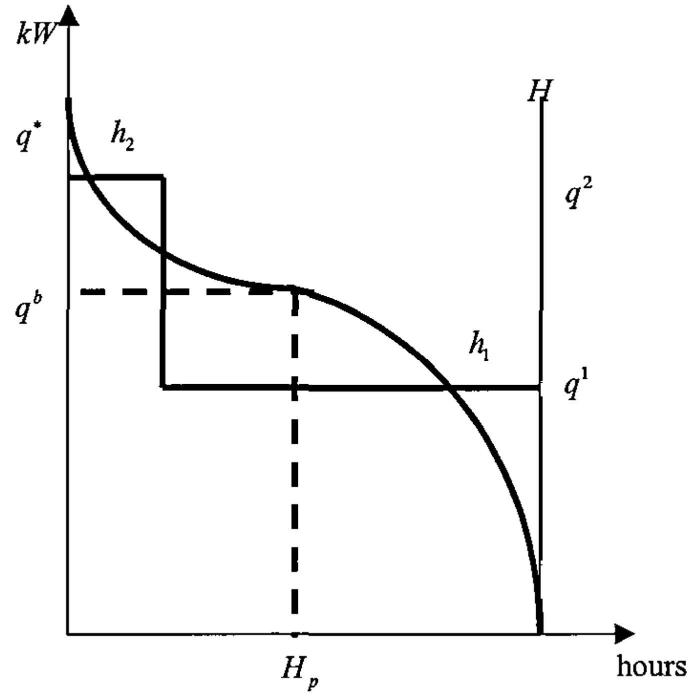

Figure 7.7.1 Profiling

It is cost efficient to use peaking capacity to supplement baseload for a period of

$$H_p = \frac{c^b - c^p}{r^p - r^b} \text{ hours} \tag{7 7.9}$$

The stepped load profile identifies an off-peak period with average demand of $h_1 q^1$ kWh, and a peak period with average demand of $h_2 q^2$ kWh. The welfare analysis must be formulated in terms of the periods identified in the profile, so that the sum of consumer and producer surplus is

$$W = h_1 \int_0^{q^1} p(q)dq + h_2 \int_0^{q^2} p(q)dq - q^1[c^b + r^b H - (c^p + r^p h_2)] - q^2[c^p + r^p h_2] \tag{7 7.10}$$

Welfare is maximised by differentiating equation 7.7.10 with respect to q:

$$\frac{\partial W}{\partial q^1} = h_1 p_1 - \left(c^b - c^p\right) - r^b H + r^p h_2 = 0 \tag{7.7.11}$$

$$\frac{\partial W}{\partial q^2} = c^p + r^p h^2 = 0 \qquad (7.7.12)$$

Substituting $c^b - c^p = H_p\left(r^p - r^b\right)$ into equation 7 7.11, efficient tariffs are:

$$h_1 p_1 = r^b\left(H - H_p\right) + r^p\left(H_p - h_2\right) \qquad (7.7\ 13)$$

$$h_2 p_2 = c^p + r^p h_2 \qquad (7.7.14)$$

Therefore the peak period contributes towards the capital cost of generating plant Efficient load profile durations are given by:

$$\frac{\partial W}{\partial h_1} = \int_0^{q^1} p(q)dq = \frac{\partial W}{\partial h_2} = \int_0^{q^2} p(q)dq - r^p[q^2 - q^1] \qquad (7.7.15)$$

In any given period, the company's measurement error from figure 7.7.1 is:

$$\Delta Q_h = \int_h^{h+\Delta h} Q(h)dh - \sum_{j \in \Delta h} Q_j h_j \qquad (7.7.16)$$

where $h \in (H)$. Therefore the distortion in social welfare for a whole year is

$$\Delta W = \sum_{h=1}^{17520} (P_h - MC_h)\Delta Q_h \qquad (7.7.17)$$

Private profit distortions are similarly derived as

$$\Delta \pi = \sum_{h=1}^{17520} (MR_h - MC_h)\Delta Q_h \qquad (7.7.18)$$

Given the assumption of a downward sloping demand schedule, the effect on private profit will be at least as great as social welfare. Suppliers will therefore have an incentive to mitigate these errors An algorithm is used to adjust for the fact that some customers will use proportionately more electricity in the same period than others such as customers on multi-rate tariffs. Nevertheless errors will persist until remote metering technology that can store data 24 hours a day for a specific period of time is cost effective to be installed nationally This is the crucial factor which to date has stifled tariff innovation as the previous section discussed.

7.8 Conclusion

Retail supply does not exhibit natural monopolistic characteristics, so the attempt to liberalise this market is warmly welcomed because a monopoly cannot possibly hope to satisfy the needs of all of its customers Before this is possible, charging for access to the distribution network has to be implemented in a way that does not prevent efficient suppliers from entering the market. This is why the underlying principles of efficient component pricing rules (ECPR) are supported by the author, because they discourage the inefficient supplier from entering the market, while providing sufficient revenues for the distribution company to continue to operate and invest in the network

A liberalised market however will lead to supply companies merging to take advantage of economies of scale and scope. If there are fewer than six national supply companies, many of the benefits of liberalisation may be extracted by the retail companies. These issues have been raised in the supermarket industry where concerns have arisen over their bargaining power when dealing with producers and customers alike Moves towards vertical integration of generating and supply businesses is also a concern because they may raise barriers to entry for new entrants in either sector which will ultimately harm the customer I believe that the customer would be best served under vertical seperation of generation and supply assets The threat of potential entry is an important incentive for managers to continue to innovate and provide new services to customers at reasonable prices.

Ofgem (2000b) has carried out regular surveys monitoring customer opinion. The survey found that cheaper prices (87%) was one of the most significant factors in a customer's decision about whether or not to change supplier. The survey reports that of those customers who have information on price and payment terms, they have found it easier to compare prices compared to previous surveys. However there still remains a problem in comparing prices, because the information is unclear or confusing Of concern, there is evidence that a lack of knowledge about price differences may be impacting upon the degree of switching taking place About 37% of non-switchers thought that there were no savings from switching supplier. A conclusion that can be drawn from this survey is that to increase the degree of switching better and clearer information on tariffs is required from companies.

8 Conclusions

The electricity industry was once considered to exhibit the characteristics of a natural monopoly Attitudes have changed since the 1980s, so the thesis has focussed attention on some of the major issues that have arisen in the deregulated industry. In this final chapter, a summary of conclusions and lessons that can be drawn is provided under the headings of developments in industry structure, performance of regulated companies, current regulatory issues, efficient pricing, and liberalisation of the retail supply market.

Developments in industry structure

Deregulation of the industry leading up to privatisation challenged many assumptions about how upstream and downstream businesses should be structured. Experience has proved that the vertical seperation of generation and transmission is both feasible and desirable from a competition perspective British Telecom is useful example for demonstrating that effective competition is harder to achieve when the dominant firm remains vertically integrated Vertical seperation of the potentially competitive businesses from the monopolistic assets is conducive for introducing competition, because there is no real threat of the regulated business cross-subsidising competitive services

In attempting to rush through the privatisation of the industry, the then government limited the nature of the horizontal seperation of the generation industry, which has consistently inhibited effective competition for the upstream business. Wholesale costs of electricity account for over half of the final bill The event study on pool prices supports the argument that the major price-setting generators have been able to use strategic behaviour for keeping pool prices higher than underlying input costs would suggest Attempts by the regulator to take remedial action have taken a decade to reduce the market share of the two major coal fired generators, National Power and Powergen, through forced divestment of plant. A clear lesson from this is that it is easier to achieve reform leading up to privatisation, but much harder to take corrective action afterwards

Vertical seperation of the electricity supply industry did not go far enough in 1990 It is possible for a regional electricity company (REC) to cross-subsidise a portion of the competitive supply business via its monopolistic distribution business. Ring fencing the two businesses through separate licences is a possible solution Market forces however are slowly changing the structure with some Recs choosing to exit the supply business and concentrate efforts in the regulated distribution business.

Vertically integrated generators will have a guaranteed market for proportion of its output. Liquidity of the wholesale market may be reduced especially since the compulsory pool is being abolished in exchange for bilateral trading and a very short-term balancing market. If the balancing market accounts for small volumes, the market will be thin, and it will be difficult for a potentially new generator who is not vertically integrated to finance entry into the market.

A lesson that can be drawn from other commodity markets such as oil is that competition is promoted if there are liquid derivatives markets. This should be the main priority for the regulator. Removing the prospect of tacit collusion is an essential ingredient for creating confidence in the derivatives market for speculators A possible solution could involve the size of infra marginal capacity through additional divestment of plant. Reforming the auction design is another option, which has been taken up by the regulator and is discussed under the heading of efficient prices.

Performance of regulated businesses

Regulation of the utility industry has moved on considerably since the privatisation of British Telecom in 1984 Price cap regulation envisaged by Littlechild (1983) of light regulatory burden, appropriate incentives, and promoting competition wherever feasible has been a partial success, but the differences between price cap and rate of return regulation are only apparent during the first *regulatory contract.* Thereafter the regulator will calculate a rate of return that is applied to the regulatory asset base.

Newbery and Pollitt (1997) would although significant productivity gains have been delivered since privatisation customers had not benefited until after 1997.argue that these benefits have only started after 1997 Analysis undertaken has shown however that wide disparities in productivity remain between the distribution business *Frontier* companies averaged over 8% per year since 1990, but the industry average was only 6.5%. Regional distribution companies allow the regulator to use comparative analysis at price reviews. Inefficient firms could be incentivised to move closer towards the efficient frontier if a pure form of yardstick regulation was applied Empirical work however suggests that inefficient firms have not been *catching up* with frontier distribution businesses

Current regulatory issues

The information and incentives project (IPP) attempts to extend benchmarking to cover quality of service. Quality of service incentives is limited to the guaranteed standards of service in the regulatory contract. IIP is being developed because the current operation of the price control allows firms to "beat" the price cap by reducing costs, but this may not be an efficient option if it leads to a decline or no improvement in the quality of service provided to customers. There is therefore potential for incentives to be distorted. Measuring performance by interruptions may also lead to the perverse result of cutting back on planned maintenance.

Future work will have to select outputs, develop an output-based incentive regime, improve monitoring of performance between reviews, and review existing efficiency incentives Improving comparability across companies could be achieved by measuring performance at a disaggregated level, but this will have to be balanced against the additional costs of reporting more detailed information. Rewarding performance on a relative basis provides strong incentives for companies to become the best, but this will mean that performance measurement will rely on standardised measurements.

The precedence for a comparison of different levels of service indicators is in water. In 1999 a service performance index was created and companies were ranked according to their levels of service A quality of service adjustment amounting to ± 0 5% of regulated revenue was made to the price determination Those companies who outperformed the average were given a more lenient price cap of

$RPI-(X-0.5)$ while companies that underperformed the average were forced to make even deeper price cuts of $RPI-(X+0.5)$ CAPEX efficiencies were dealt with through a rolling regulatory asset base (RAB) adjustment. A rolling mechanism allows each firm to keep some of the efficiency benefits for a full five-year period. Incentives are independent of time, but more frequent scrutiny of data is required under this regulatory environment. High quality data is required so the costs of collecting this must be balanced against the benefits of convergence to a competitive outcome.

Relative price regulation could be employed, where the RAB is adjusted for differences in the average rate of return in the industry and the cost of capital for the industry. This process corrects for errors in forecasts of costs Furthermore it mimics the competitive market, so best performing firms achieve above average returns and worst performers earn less than average, so there is always an incentive to outperform competitors A potential danger with this approach is that some companies may not earn a sufficient rate of return to continue to perform its duties as contained in the licence. As a result there would have to be a price floor to ensure an adequate revenue stream.

Incentive contracts could be developed along the lines of Laffont and Tirole (1986). If the regulator does not know the cost function, it could offer a menu of tariffs. This would range from a contract designed for firms providing a high quality of service to a contract for low quality of service indicators A firm who chose the high quality or service contract would retain most of the efficiency gains, where targets set would be tight. In contrast a firm that chose the low quality option would pass most of the efficiency gains back to the customer

Yorkshire Water is the first utility company to announce a not-for-profit asset mutual plan. Distribution companies in the electricity industry may consider this model especially if the stock market values their shares at less than the value of their assets. Raising new equity capital will actually reduce the value of their shares, so it must raise debt to finance investment. The mutual model is a structure in which all the finance can be provided by debt There will be regulatory concerns over efficiency and incentives because the operation of assets will be offered in the form of a franchising contract. Some of the key issues will involve the length of the contract, and the incentives for efficiency built into them

Efficient pricing

The structure of transmission prices in England and Wales is inefficient because network losses and constraints are averaged across all customers rather than being attributed to customers who directly impose these network problems. A possible remedy suggested involve the introduction of transmission property rights, which are allocated according to a set of pre-defined trading rules. Property rights are traded in a decentralised market place to achieve an efficient allocation whilst raising sufficient revenue for the system operator to perform its regulated functions. Appropriate pricing signals are sent which incentivise generators to locate in the South of England and thus alleviate some of the network losses and constraints

Efficient access of the local distribution network is achieved through an access charge, which is related to an efficient component pricing rule (ECPR) Entry is encouraged if a new entrant is able to undercut the incumbent by having lower avoidable costs, which in this case are the costs of purchasing electricity from generators

Under the new electricity trading arrangements (NETA), auction theory has been used to justify abolishing the uniform system marginal price, because it is easier for tacit collusion to take place compared to a pay-as-bid auction. One of the drawbacks of a pay-as-bid auction is that it does not necessarily ensure an efficient allocation compared to an ascending auction whereby the lowest cost generators are dispatched first It remains to be seen whether these changes will increase welfare but the fact that a market abuse condition is being actively proposed by OFGEM suggests that collusion is still a real possibility Simplifying the existing Pool rules, and encouraging the development of an active demand side combined with further improvements in the competitive generating market would be a sensible incremental approach to take at the moment. An analysis of these changes could then be monitored before deciding whether more fundamental change in the design of the auction is required

Liberalisation of the retail supply market

Retail supply competition for domestic customers is here, although not all customers have benefited to date. Direct-debit and standard quarterly billed customers have the ability to switch to cheaper supplies, but the historical cross-subsidy of pre-payment meters has prevented significant rivalry in this market Tariff innovation has been slow with British Gas's announcement that they have abolished all standing charges as the only real significant development. This has happened in response to public opinion, which has suggested that they dislike paying a charge that is not related to consumption Virgin has followed suit when they recently introduced an internet website selling electricity and gas. Customers who remain with their service for more than one year have an environmental incentive to reduce consumption, in the form of a £1 reduction in their bill for each 1% reduction in energy consumption. In addition they offer to sell energy efficient appliances at a discount from the high street price to encourage this behaviour.

Opportunities to offer seasonal and time of day tariffs are dependent upon metering and meter reading technology. Over time the costs will fall as meter reading companies consolidate and achieve the critical mass to make this a feasible development. Creation on liquid derivatives markets combined with new technology could encourage financial players to construct energy contracts that are tailored to match the characteristics of customers. Only then will liberalisation have delivered many of the benefits to customers it was intended to achieve from the outset.

Appendix A

Model 1

Dependent variable = LP		524 observations
Regressor	Coefficient	t-statistic
C	-1.647	-1.809
LP(-1)	0.616	14.043
LP(-2)	0.102	2.342
LDF	1.482	5.661
LDF(-1)	0.529	1.158
LDF(-2)	-1.014	-2.236
LDF(-3)	-0.752	-2.817
R-Squared	0.612	
F-statistic	135.757	
	LM version	
Serial Correlation	0.163 [0.686]	
Functional Form	2.874 [0.090]	
Normality	218.311 [0.000]	
Heteroscedasticity	0.901 [0.342]	
Predictive Failure	252.917 [0.000]	

Model 2

Dependent variable = LP		524 observations
Regressor	Coefficient	t-statistic
C	-0 580	-1.219
LP(-1)	0.713	19.007
LP(-2)	0.066	1.499
LP(-3)	0 048	1 351
LDF	1.817	14 035
LDF(-1)	-0.229	-1.243
LDF(-2)	-0 868	-4.806
LDF(-3)	-0 608	-4 011
R-Squared	0 825	
F-statistic	160 039	
	LM version	
Serial Correlation	0 177 [0 673]	
Functional Form	2.848 [0.091]	
Normality	80.027 [0.000]	
Heteroscedasticity	0.037 [0.847]	
Predictive Failure	2157.6 [0.000]	

Model 3

Dependent variable = LP		524 observations
Regressor	Coefficient	t-statistic
C	-4 064	-4 986
LP(-1)	0.546	13.712
LP(-2)	0.1454	3 783
LDF	1 886	10.030
LDF(-1)	0 553	1.794
LDF(-2)	-1.958	-9.242
R-Squared	0 727	
F-statistic	195 938	
	LM version	
Serial Correlation	0.349 [0.554]	
Functional Form	1.104 [0 293]	
Normality	84.390 [0.000]	
Heteroscedasticity	1.759 [0 185]	
Predictive Failure	782.845 [0 000]	

Model 4

Dependent variable = LP		476 observations
Regressor	Coefficient	t-statistic
C	-5 600	-1.827
LP(-1)	0.798	17.602
LP(-2)	0 113	2.520
LDF	10 240	21.144
LDF(-1)	-5.769	-6.749
LDF(-2)	-1.989	-2.351
LDF(-3)	-1.927	-3.581
R-Squared	0 853	
F-statistic	452.946	
	LM version	
Serial Correlation	1 432 [0.232]	
Functional Form	0.625 [0.429]	
Normality	111.047 [0 000]	
Heteroscedasticity	0 148 [0 700]	
Predictive Failure	1206 7 [0 000]	

Model 5

Dependent variable = LP	500 observations	
Regressor	Coefficient	t-statistic
C	-9.726	-5 051
LP(-1)	0 619	17.488
LDF	3 957	15 967
LDF(-1)	-2.041	-5.733
LDF(-2)	-1.533	-4.900
LDF(-3)	0 663	2 695
R-Squared	0 659	
F-statistic	67.115	
	LM version	
Serial Correlation	0 0002 [0.996]	
Functional Form	1.675 [0 196]	
Normality	134.202 [0.000]	
Heteroscedasticity	4.054 [0 044]	
Predictive Failure	645 893 [0 000]	

Model 6

Dependent variable = LP		500 observations
Regressor	Coefficient	t-statistic
C	-13.699	-7 084
LP(-1)	0 700	16.745
LP(-2)	-0.176	-4 519
LDF	2 139	7.647
LDF(-1)	-0 685	-2.229
R-Squared	0 796	
F-statistic	385.115	
	LM version	
Serial Correlation	0 433 [0.511]	
Functional Form	0 649 [0.420]	
Normality	121.375 [0 000]	
Heteroscedasticity	1.714 [0 190]	
Predictive Failure	311 473 [0 000]	

Model 7

Dependent variable = LP		524 observations
Regressor	Coefficient	t-statistic
C	-26 874	-8.368
LP(-1)	0.632	0 031
LDF	6 198	9.009
LDF(-1)	0 766	0 680
LDF(-2)	-6 089	-5.511
LDF(-3)	1.799	2 588
R-Squared	0.734	
F-statistic	203.739	
	LM version	
Serial Correlation	0 2003 [0 654]	
Functional Form	2 851 [0 091]	
Normality	185 855 [0 000]	
Heteroscedasticity	2.231 [0 135]	
Predictive Failure	738 694 [0 000]	

Appendix B

Table 6 7 1

Dependent variable = Log(M)		96 panel observations
Generalised Least Squares		12 cross-sections
Regressor	Coefficient	t-statistic
Log(OPEX)	-0 00301	-23 400
Log(KSTOCK)	-0 0000218	-3.431
Log(GWh)	0.0000123	2 727
Log(MAXD)	0.0000111	0 961
Log(REG)	0 01366	2 441
Log(CUSDEN)	-0 0000317	-0 182
Log(AVAIL)	-0 0000104	-0.292
Log(SECUR)	-0.000231	-2 022
Log(FAULT)	0 000699	0 945
Fixed Effects		
Eastern	0.310	
East Midlands	0 241	
London	0.469	
Manweb	0 191	
Midlands	0 299	
Northern	0 181	
Norweb	0.288	
Seeboard	0.251	
Southern	0 277	
Swalec	0 219	
Sweb	0 189	
Yorkshire	0.259	
R-Squared	0 989	
F-statistic	902 902	

Table 6 7 2

Dependent variable = Log(M) Generalised Least Squares	96 panel observations 12 cross-sections	
Regressor	Coefficient	t-statistic
Log(OPEX)	-0 003002	-32.129
Log(KSTOCK)	-0.0000186	-5 095
Log(GDP)	0 0000264	8 023
Log(REG)	0 013445	4.435
Log(SECUR)	-0.000125	-2.699
Fixed Effects		
Eastern	0.436	
East Midlands	0.304	
London	0.288	
Manweb	0.176	
Midlands	0.362	
Northern	0.148	
Norweb	0 328	
Seeboard	0 164	
Southern	0 319	
Swalec	0 126	
Sweb	0 097	
Yorkshire	0.311	
R-Squared	0.997	
F-statistic	5767.351	

Table 6 7.3

Dependent variable = Log(M)	96 panel observations	
Generalised Least Squares	12 cross-sections	
Regressor	Coefficient	t-statistic
Log(OPEX)	-0.003062	-40.063
Log(Output Cycle)	-0 333277	-5.126
Log(MAXD)	0.0000175	2 384
Log(REG)	0 018360	5 653
Log(SECUR)	-0.000126	-1.997
Fixed Effects		
Eastern	0.867	
East Midlands	0.775	
London	0.840	
Manweb	0 666	
Midlands	0 806	
Northern	0 632	
Norweb	0 768	
Seeboard	0.722	
Southern	0 827	
Swalec	0.623	
Sweb	0 621	
Yorkshire	0 766	
R-Squared	0 994	
F-statistic	3103.496	

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